Trinidad & Tobago Gas Master Plan

Final Report

prepared for:

MINISTRY OF ENERGY AND ENERGY AFFAIRS

September 2015

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POTEN & PARTNERS

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Contents

Glossary

1. Executive Summary 1-1

1.1 Introduction 1-1

1.2 E&P Activity in T&T 1.3

1.3 Gas Transportation 1.9

1.4 Contracting & Gas Supply Arrangements 1.10

1.5 Fiscal Competitiveness 1.15

1.6 Reserves & Production Outlook 1.17

1.7 Mobilising Production 1.24

1.8 The Downstream Portfolio 1.31

1.9 Gas Pricing in T&T 1.38

1.10 Downstream Commercial Arrangements & Value Generation 1.40

1.11 Gas Supply & Demand Situation 1.45

1.12 Future Mid & Downstream Sector 1.49

1.13 Conclusions 1.60

1.14 Recommendations 1.67

2. Introduction 2-1

2.1 Background 2-1

2.2 The Energy Sector's place in the T&T economy 2-4

2.3 T&T Gas Sector Structure 2-10

2.4 Gas Sector Policy in T&T 2-13

2.5 The Gas Master Plan 2-14

3. Upstream E&P Activity Status 3-1

3.1 Exploration Activity 3-1

3.2 Acreage Award 3-2

3.3 Exploration & Development Technology 3-5

3.4 Historical Production 3-7

4. Upstream - Gas Transportation 4-1

4.1 T&T Gas Transportation System 4-1

5. Upstream – Contracting & Gas Supply Arrangements 5-1

5.1 Upstream Contractual Arrangements 5-1

5.2 Review of Current Gas Supply Arrangements 5-4

5.3 Security of Supply ... 5-12

6. Upstream – Fiscal Competitiveness of T&T ... 6-1

6.1 Introduction ... 6-1

6.2 T&T Fiscal Regime ... 6-2

6.3 Selection of Benchmark Countries ... 6-5

6.4 Gas Reserves Competitive Position ... 6-12

6.5 Gas Market Accessibility ... 6-13

6.6 Fiscal Regime Attractiveness ... 6-15

6.7 Ease of Doing Business ... 6-19

6.8 Conclusions ... 6-23

7. Upstream – Reserves & Production Outlook ... 7-1

7.1 Reserves Terminology ... 7-1

7.2 T&T Reserves Base Evolution ... 7-2

7.3 Operator Development Plans ... 7-12

7.4 Medium-Term Gas Supply ... 7-20

7.5 Conclusions ... 7-25

8. Upstream – Mobilising Production ... 8-1

8.1 Review of Shallow-Water Unsanctioned Projects ... 8-1

8.2 Mobilising Shallow-Water Unsanctioned Projects ... 8-11

8.3 Mobilising Deepwater Gas ... 8-23

8.4 Mobilising Cross-Border Gas ... 8-25

9. Downstream – Portfolio, Pricing & Markets ... 9-1

9.1 Downstream Portfolio ... 9-1

9.2 Downstream Markets & Product Pricing ... 9-12

9.3 Gas Pricing ... 9-27

10. Downstream – Commercial Arrangements & Value ... 10-1

10.1 Introduction ... 10-1

10.2 LNG ... 10-1

10.3 NGC-Supplied Industries ... 10-21

10.4 Netback Price & GORTT Take Comparison ... 10-34

10.5 Netback Price Projections ... 10-40

11. Downstream – Gas Supply & Demand Situation ... 11-1

11.1 Current Supply / Demand Situation ... 11-1

11.2 Future Supply / Demand Situation ... 11-10

12. Future Mid & Downstream Sector ... **12-1**
12.1 Introduction ... 12-1
12.2 Prioritisation / Allocation of Gas ... 12-2
12.3 Sectoral Structural Issues & The Role of NGC ... 12-9
12.4 Options for LNG ... 12-18
12.5 Recommendations & Implementation ... 12-21
13. Future Project Development ... **13-1**
13.1 New Gas-Based Projects Evaluation Framework ... 13-1
13.2 Development of Downstream Derivatives ... 13-5
13.3 The Role of National Energy in Facilitating Development ... 13-6
13.4 Competitiveness of T&T – Industry Perceptions ... 13-9
14. Institutional – Policy & Legislation ... **14-1**
14.1 Institutional & Regulatory Arrangements ... 14-1
14.2 Fiscal Regime ... 14-12
14.3 Gas Sector Policy ... 14-16
14.4 Regulatory Implementation ... 14-23
14.5 HSE Policies & Practices ... 14-28
14.6 Location of Gas-Based Industries – Land Use Planning ... 14-37
14.7 Institutional Capacity ... 14-49
15. Institutional – Local Content & Services ... **15-1**
15.1 Introduction ... 15-1
15.2 T&T Policy on Local Content & Services ... 15-2
15.3 Economic Rationale for a Local Content Policy ... 15-5
15.4 Measuring Local Content ... 15-9
15.5 T&T Achievements in Local Content ... 15-10
15.6 Recommended Policy for Enhancing Local Content & Costs ... 15-17
16. Institutional – Sustainable Development ... **16-1**
16.1 Introduction ... 16-1
16.2 Policy Framework ... 16-1
16.3 Energy and the Environment ... 16-4
16.4 Economic Development ... 16-13
16.5 Conclusions & Recommendations ... 16-16
17. Institutional – Integration with Non-Energy Sector ... **17-1**

17.1 Overview 17-1

17.2 Natural Resources Funds 17-1

17.3 The Heritage & Stabilisation Fund 17-4

17.4 Investment in the Non-Energy Sector 17-7

18. Conclusions & Recommendations 18-1

18.1 Conclusions 18-1

18.2 Recommendations 18-8

Appendices

Appendix A: Scope of Work A-1

Appendix B: New Developments in Upstream Exploration B-1

Appendix C: Analysis of T&T Incumbents C-1

Appendix D: Reserves Terminology D-1

Appendix E: Benchmarking of Country Competitiveness Indices E-1

Appendix F: Gas Utilisation Options F-1

Appendix G: Global Economic Outlook & Energy Trends G-1

Appendix H: Market Analysis H-1

Appendix I: Financial Analysis I-1

Appendix J: Global Gas Value Chain Experience J-1

Appendix K: Legislation & Regulation K-1

Appendix L: Gas Pipeline Infrastructure Schematic L-1

Appendix M: Case Studies on Local Content M-1

Appendix N: Lessons from Other Gas-Short Countries M-1

Abbreviations

ACQ	Annual Contract Quantity	ECMA	East Coast Marine Area
ALNG	Atlantic LNG	EITI	Extractive Industries Transparency Initiative
ARSF	Interim Revenue Stabilisation Fund	EMA	Environmental Management Authority
AUM	Ammonia Urea Melamine	EOG	EOG Resources Trinidad Ltd
bbl	barrel	E&P	Exploration and Production
Bcf	Billion cubic feet	EU	European Union
Bcm	Billion cubic metres	FERC	Federal Energy Regulatory Commission
BGTT	British Gas Trinidad &Tobago	FID	Financial Investment Decision
boe	Barrel of oil equivalent	FLNG	Floating Liquefied Natural Gas
bbl/d	Barrels per day	FO	Farm Out
bpTT	British Petroleum Trinidad &Tobago	GDP	Gross Domestic Product
Bcf/d	Billion Standard Feet per Day	GORTT	Government of Republic of T&T
CAGR	Compound Average Growth Rate	GSA	Gas Sales Agreement
CBTT	Central Bank of T&T	HBI	Hot briquetted iron
CCGT	Combined Cycle Gas Turbine	HH	Henry Hub
CEC	Certificate of Environmental Clearance	HSF	Heritage & Stabilisation Fund
CNC	Caribbean Nitrogen Company	IEA	International Energy Agency
CNG	Compressed Natural Gas	IMF	International Monetary Fund
CT	Corporation Tax	IRD	Inland Revenue Division
CTO	Coal to Olefins	JCC	Japan Custom Cleared
DES	Delivered Ex Ship	JKT	Japan, Korea, Taiwan
DRI	Direct Reduced Iron	LICS	Light Industrial & Commercial Sectors
E&P	Exploration & Production	LNG	Liquefied Natural Gas
ECA	Emissions Control Area	LO	Lease Operator

Abbreviations (contd)

LOFO	Lease Operatorship & Farm Out	PLNL	Port Lisas Nitrogen Limited
LPG	Liquid Petroleum Gas	PPGPL	Phoenix Park Gas Processors Ltd
Mcf	Thousand Standard Cubic Feet	PPT	Petroleum Profits Tax
MEEA	Ministry of Energy and Energy Affairs	PSC	Production Sharing Contract
MHTL	Methanol Holdings Trinidad Ltd	psig	Pounds per Square inch (Gauge)
MMBtu	Million British Thermal Units	SPA	Supply & Purchase Agreement
MMt	Million Metric Tonnes	SPT	Supplemental Profits Tax
MMt/y	Million Metric Tonnes per Year	Tcf	Trillion Cubic Feet
MMcf/d	Million Standard Cubic Feet per Day	TD	Total Depth
MoFE	Ministry of Finance	TGU	Trinidad Generation Unlimited
MOU	Memorandum of Understanding	Trinling	Trinling Ltd (LNG Marketing)
NBP	National Balancing Point (UK)	TPES	Total Primary Energy Supply
NCMA	North Coast Marine Area	TT$	Trinidad and Tobago Dollar
NEC	National Energy Corporation	TTDAA	T&T Deepwater
NGC	National Gas Company	T&TEC	T&T Electricity Commission
NGL	Natural Gas Liquids	TTEIT	T&T Extractive Industries Transparency Initiative
NGV	Natural Gas Vehicles	TWh	Terawatt Hour
OAG	Office of the Auditor General	UAN	Urea Ammonia Nitrate
OCGT	Open Cycle Gas Turbine	UFQ	Upward Flexibility Quantity
PCS	PotashCorp	US$	United States Dollar
PdVSA	Petroleos de Venezuela SA	VAT	Value Added Tax
PEMEX	Petroleos Mexicanos	WHT	Withholding Tax
PFLE	Point Fortin LNG Exports	WO	Work Over

1.1 INTRODUCTION

1.1.1 The Gas Sector in Trinidad & Tobago

The gas industry in Trinidad & Tobago (T&T) is well established. The country has been a producer of oil and gas for over a century and natural gas has been commercially utilised since 1953. The major development of the gas sector started in the 1970s prompted by the discovery of large gas reserves off the east coast of Trinidad. Today the energy sector is now dominated by gas production, which accounts for almost 90 percent of the energy sector production on a barrel of oil equivalent (boe) basis.

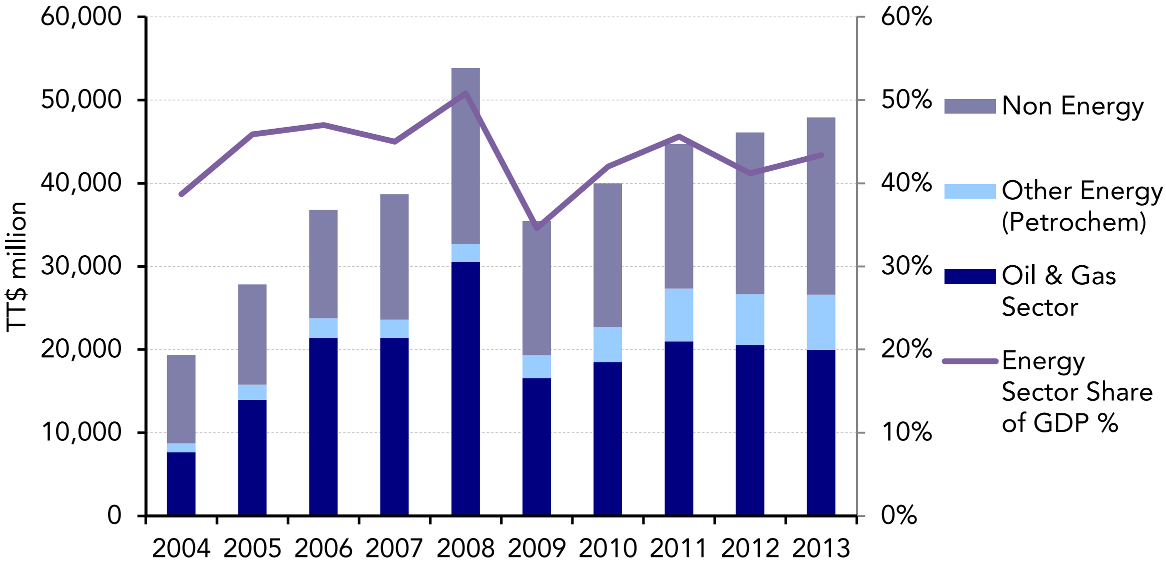
The Government of T&T (GORTT) initiated the development of gas based industries and industries producing ammonia and methanol and also an iron and steel complex at Point Lisas on the west coast of Trinidad. This development continued through the 1990s with the addition of LNG plants at Point Fortin. Today T&T has a world-scale natural gas sector consuming over 4 Bcf/d. Most of this gas is exported either in the form of LNG (which represents ~55% of total gas consumption) or gas-based petrochemicals (which represent ~31% of total consumption). The country is a major exporter of all of these products, and in the case of ammonia and methanol it is presently the world's largest exporter. The domestic gas market is relatively small and consists primarily of supply to the power sector, the refinery, the iron & steel industry and other small users.

1.1.2 Importance of the Gas Sector to T&T Economy

T&T's economy is highly dependent on the energy sector, which over the last decade has accounted over 40% of national GDP and around 54% of GORTT tax revenues. The sector is responsible for around 85% of the country's exports, of which the majority is from natural gas. The tax revenues from the energy sector have grown with the development of gas utilisation over the last decade and in 2013 represented around TT$ 20 billion. The IMF expects the energy sector to continue to contribute around 50% of GORTT revenue through the next 5 years.

Figure 1-1 Tax Revenues from Energy Sector & Share of GDP 2004-2013

(Source: Ministry of Finance & the Economy)



Most of the GORTT revenue is generated in the upstream sector through Petroleum Profit taxes, Royalty, PSC profit shares and Supplemental Petroleum Tax, which account for 87% of all GORTT revenue from the sector.

1.1.3 T&T Gas Sector Structure

At the present time the T&T natural gas market structure could be characterised as a single buyer structure although it retains many features of a vertically-integrated model. The key features of the current structure are as follows:

- There is limited competition in the upstream supply of gas with 4 major players and several small producers. The major producer is bpTT, which holds ~60% of the total gas production and presently holds ~ 55% of the proven reserves.
- Transmission and distribution are undertaken in a single system by a transmission system operator, in this case the parastatal National Gas Company of T&T (NGC). NGC also acts as the sole wholesaler of gas, purchasing from suppliers to market to the downstream industries, the power sector and small customers. Transportation is provided as a bundled service with gas supply. There is a bypass of NGC as two suppliers, bpTT and BG, supply gas directly to Atlantic LNG (ALNG). This bypass represents ~55% of total gas consumption.
- The downstream sector of the market is sector comprised mostly of large consumers requiring baseload gas supply whose products are for export. The domestic market is very small representing around 10% of total gas consumption into power, cement and small consumers.

There is a significant degree of vertical integration in the sector:

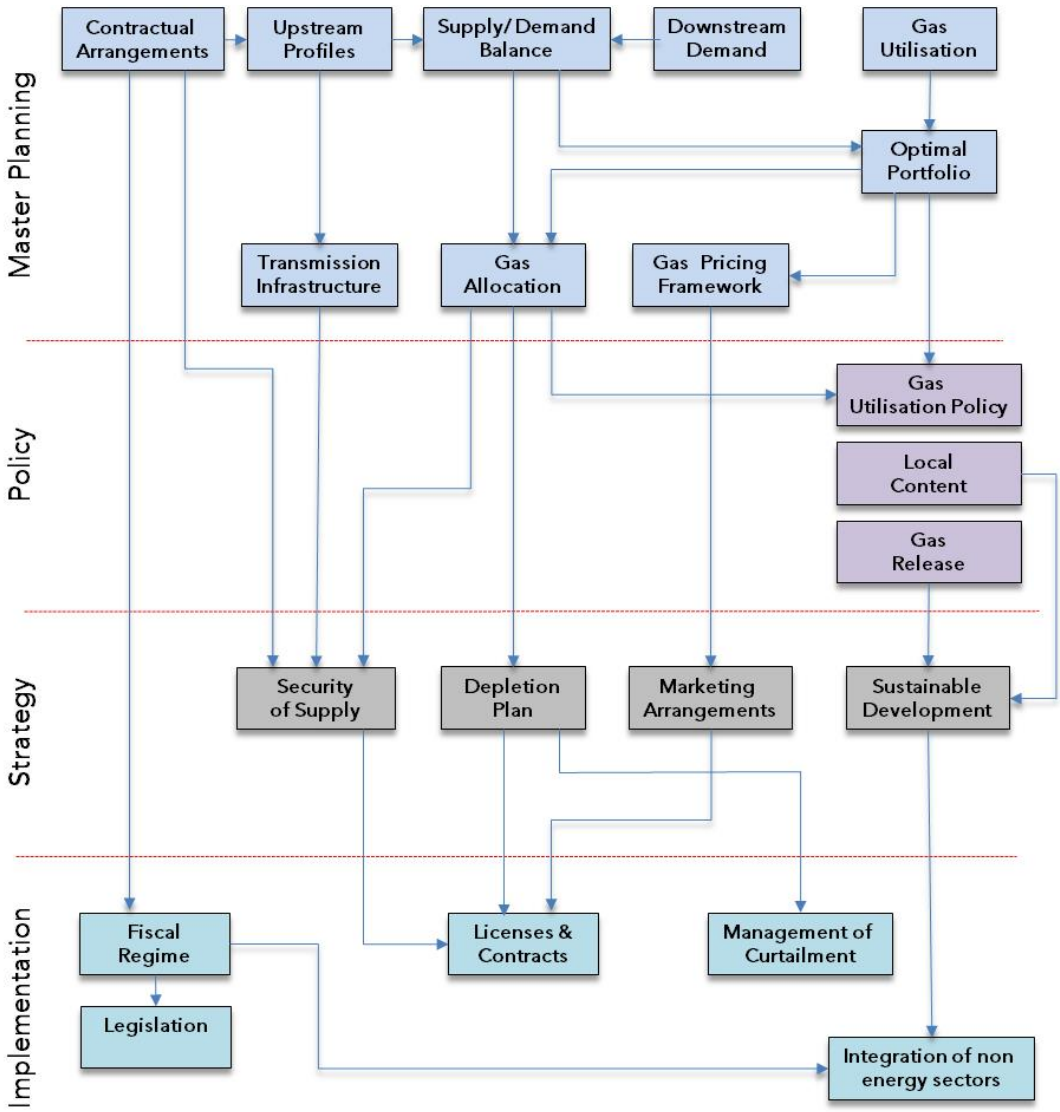
- bpTT is a major player throughout the gas chain. As well as being the dominant upstream player it has downstream interests in the Atlas methanol plant and is a major shareholder in ALNG.
- BG, the second largest upstream player is a shareholder in ALNG and a major LNG offtaker through Trains 2, 3 & 4.
- NGC is integrated throughout the chain. It is a supplier of gas, the single buyer and transporter in the midstream sector and has shareholdings in ALNG (Train 1 and Train 4) and Phoenix Park Gas Processors Limited (PPGPL). It is also an offtaker from ALNG through its TTLNG subsidiary.

There has been significant GORTT involvement in establishing the sector both as an investor and facilitator and this remains a feature to the present day.

1.1.4 The Gas Master Plan

Recent developments in both the local and global gas markets are threatening the viability of the local natural gas sub sector. The gas reserves base has been falling steadily since 2002 and the proven reserves to production (R/P) ratio was 8.3 years at the end of 2013, significantly lower than most hydrocarbon exporting economies. Upstream producers have indicated that new gas sales contract and fiscal terms will need to reflect the higher exploration, development and operating costs encountered in the upstream sector. This has significant implications for the downstream gas consuming sector.

Figure 1-2 T&T Gas Master Plan Route Map



In recognition of the threat posed by these risks and challenges to T&T's model of development of gas-based industries, the Ministry of Energy & Energy Affairs (MEEA) decided that an in-depth review into the sector must be conducted. The Gas Master Plan will act as a route map for the development of policy and strategy. The various elements of the Master Plan and their linkages are shown in Figure 1-2 above.

The Master Plan is to act as a blueprint to inform the policies that can be instituted to ensure the domestic gas sector is at the forefront of technological change and is supported by an appropriate institutional and regulatory framework for its efficient and effective management.

The guiding principles of the Master Plan are to provide a basis for:

- Maximising the value accrued by GORTT from the exploitation of T&T's gas resources, on behalf of the people of T&T.

- This means maximisation of value across the whole sector, i.e. ensuring optimum supply of gas to the existing downstream gas portfolio whilst also seeking to maximise GORTT benefit across the various value chains from the gas resources that are produced.

The key objectives of the study are to:

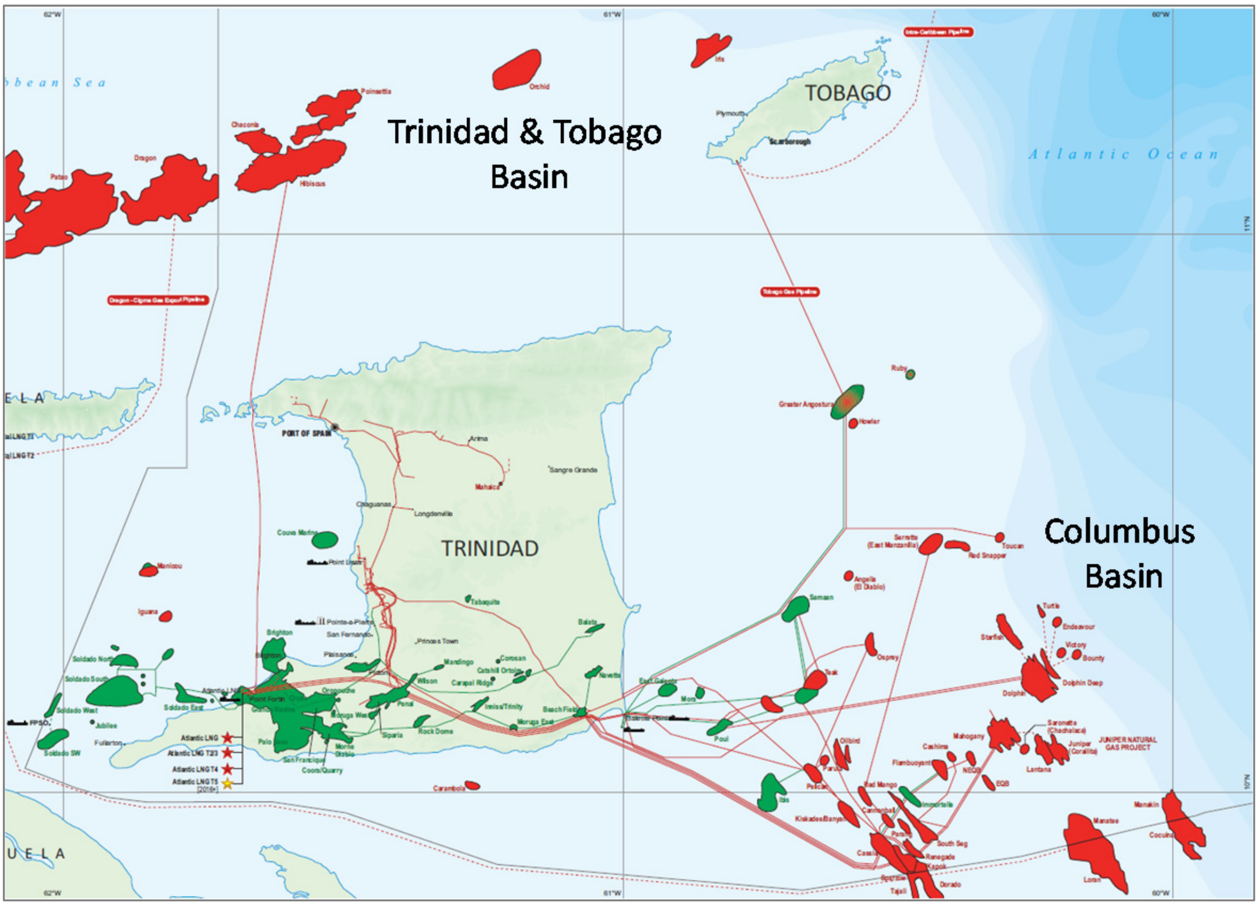
- Ensure that new exploration effort is undertaken to the maximum extent possible consistent with economic realities of the upstream sector and T&T end markets.
- Ensure all suppliers develop and supply their gas resources to the market in an optimal manner.
- Maximise rent extraction for GORTT from the gas sector subject to ensuring that all players along the chain are sufficiently incentivised to perform optimally for the country.
- Ensure sufficient gas supply to strategic downstream sectors based on national importance (e.g. the power sector and large employers).
- Ensure that if gas supply curtailment is required, it is applied on a transparent, consistent and fair basis.

1.2 E&P ACTIVITY IN T&T

1.2.1 Historical Gas Production

Gas production in T&T is from two primary producing areas, the Columbus basin to the South East of Trinidad and the Tobago Basin which runs from east to west to the north of Trinidad as shown in the Figure 1-3 figure below.

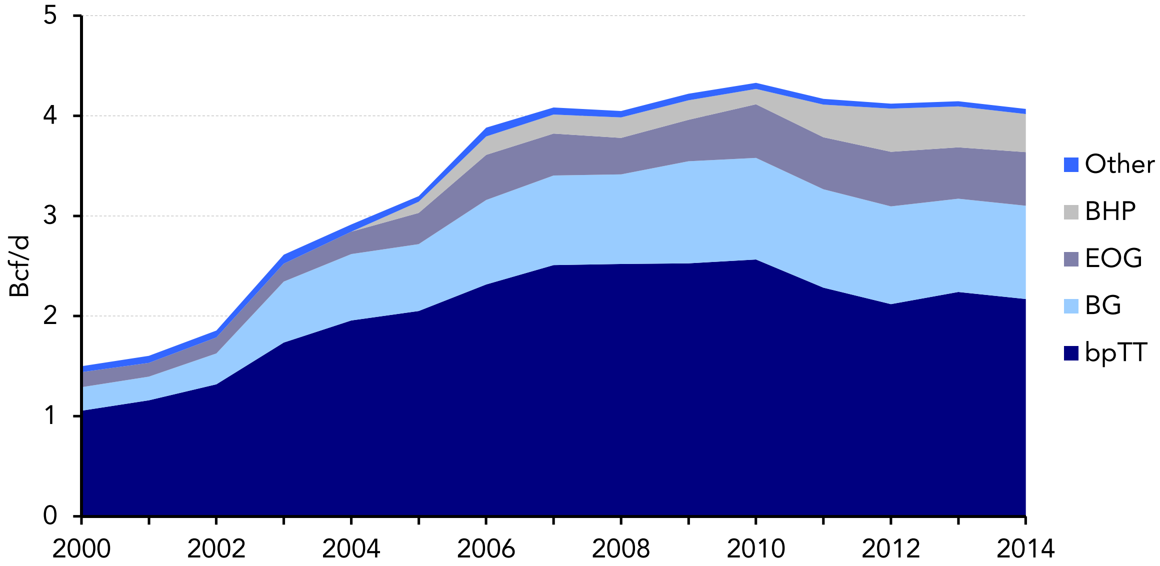
Figure 1-3 Map of Major Gas Fields in T&T
(source: Petroleum Economist)



The Columbus Basin is one of the larger gas provinces in the western hemisphere to be developed over the last few decades. Major gas fields include Immortelle, Cassia, Mahogany, Flamboyant, Amherstia, Corallita, Kapok and Mango. The Tobago Basin contains the Hibiscus, Poinsettia and Chalconia fields. These fields were discovered in the early 1980's but it was not until the 1990s that they were further developed to supply the ALNG project. These fields are grouped in the North Coast Marine Area (NCMA).

The major gas producers in T&T are bpTT (formerly Amoco), BG, EOG and BHP. Repsol, Centrica, Niko, Trinmar, NGC and Petrotrin also hold shallow water acreage at various stages of development. Licensed deepwater acreage is held by BHP, bpTT, BG and Repsol.

Figure 1-4 Historical Gas Production 2000-2013
(source: MEEA)



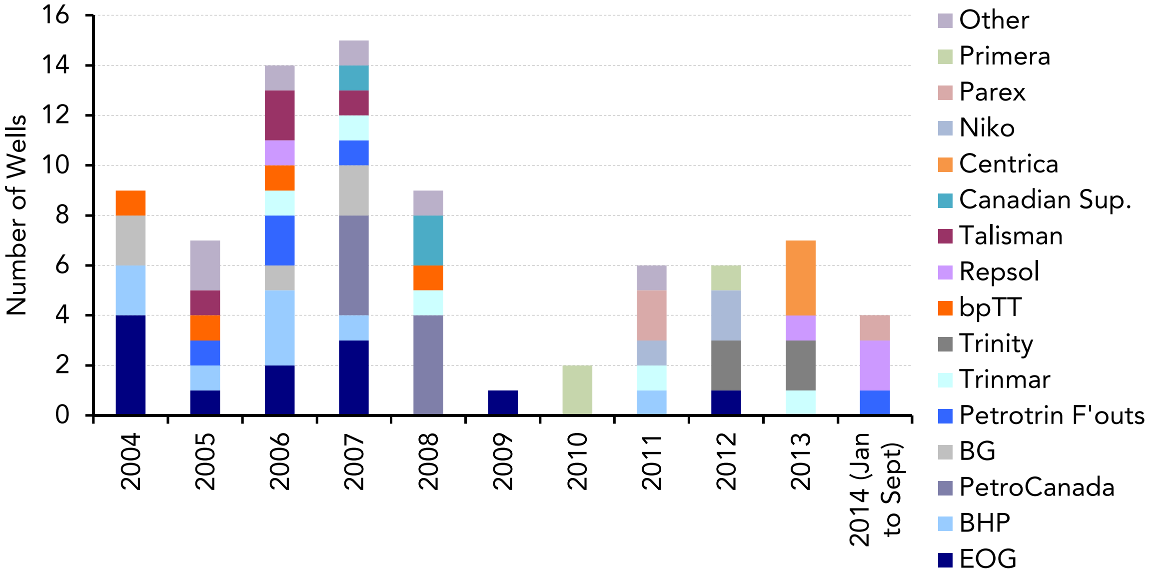
In 2014 T&T gas production was an average of 4.07 Bcf/d, with bpTT, BGTT, EOG accounting for nearly 90% of gas production in the country. bpTT is the largest gas producer in T&T, with 10 gas fields in production, mostly in the East Coast Marine Area (ECMA) of the Columbus Basin, and in 2014 produced an average of 2.17 Bcf/d, which accounted for 53% of the total production. BG produced an average of 0.93 Bcf/d (23% of the total) from seven fields in the ECMA, NCMA, and Central Block.

1.2.2 Exploration Activity

Although T&T has had a long history of onshore oil production the significant development of gas began in the late 1960's and early 1970's with the discovery and development of oil fields off the East coast of Trinidad, with which came significant volumes of gas. This initial success was followed by a twenty year period with limited exploration finds, not least because at this time there was no market in T&T to monetise gas discoveries. However, by 1993 opportunities for increased usage of gas by the domestic gas market and in the export of LNG were being developed which spurred interest in gas and a revival in exploration.

In the period from 1994 through 1998 the application of new technology and new play concepts resulted in the discovery of over 14 Tcf of gas and 300 million barrels of oil and condensate (>2.5 BBOE). These exceptional results over this short time period caused a dramatic resurgence of interest by the industry in the exploration potential in the Columbus Basin.

Figure 1-5 Exploration Drilling since 2004
(source: MEEA)



Exploration activity over the last decade dropped abruptly in 2009, and has resumed at a lower level from 2011 onwards. The exploration activity is, unsurprisingly, strongly correlated with the success of the various bid rounds and upstream blocks taken up as a result of the licensing rounds. For 2010/11 bidding rounds the PSC terms on offer from MEEA were improved and this appears to have led to more interest, awarded blocks and subsequent exploration activity. That said exploration drilling is still some way below the highs seen in 2006 and 2007 when 14 and 16 wells were drilled respectively.

1.2.3 Acreage Award

The offshore areas of T&T comprise 42,500 km^2 of which approximately half of the shallow water and one quarter of the deepwater acreage is currently leased to independent operators. Approximately 70% of the offshore contract area is continental shelf where water depths are 200 m or less. The remaining area contains the deeper water blocks where the water becomes progressively deeper towards the east, reaching over 1,000 m in some areas. T&T has a well-established licensing framework which has evolved over time from royalty type arrangements to Production Sharing Contracts (PSCs).

Exploration and Production Licences operate under a royalty structure. Twenty-two licences were awarded between 1994 and 2009. Thirty-nine PSCs have been awarded primarily between 1996 and 2013, although Block 6 PSC was awarded in 1974 and Block E in 1993. The terms of the PSCs have been adjusted over the years in response to oil and gas market conditions and the level of interest in acreage from international E&P companies.

T&T has launched regular competitive bidding rounds for acreage over the last few years, with the emphasis for most recent rounds being on deepwater blocks.

1.2.4 E&P Technology Development

The upstream oil & gas industry has become more technology-intensive over the years. The world's remaining unexploited hydrocarbons are to be found in increasingly more difficult locations or challenging geological formations. The migration to deeper water offshore prospects (deep water being considered to be depths greater than 1000 m) is probably the most significant current trend in this regard. Technical innovation has been paramount in the finding, assessing and economic exploitation of these resources.

Technological development has played a significant role in the development of T&T resources. The increased success rate in the mid 1990's was in large part due to the introduction of new technology used for prospect development. For prospects in the Columbus Basin, trap definition and fault seal are the highest risk factors. Prior to 1994, the use of 3D seismic data in Trinidad was limited to development drilling and all exploration wells were drilled based on 2D seismic data only. Since 1994 all Trinidad exploration wells have been drilled using 3D seismic data. The 3D seismic significantly helps to reduce risk for trap definition by better imaging the complex faulted structures in the Columbus Basin

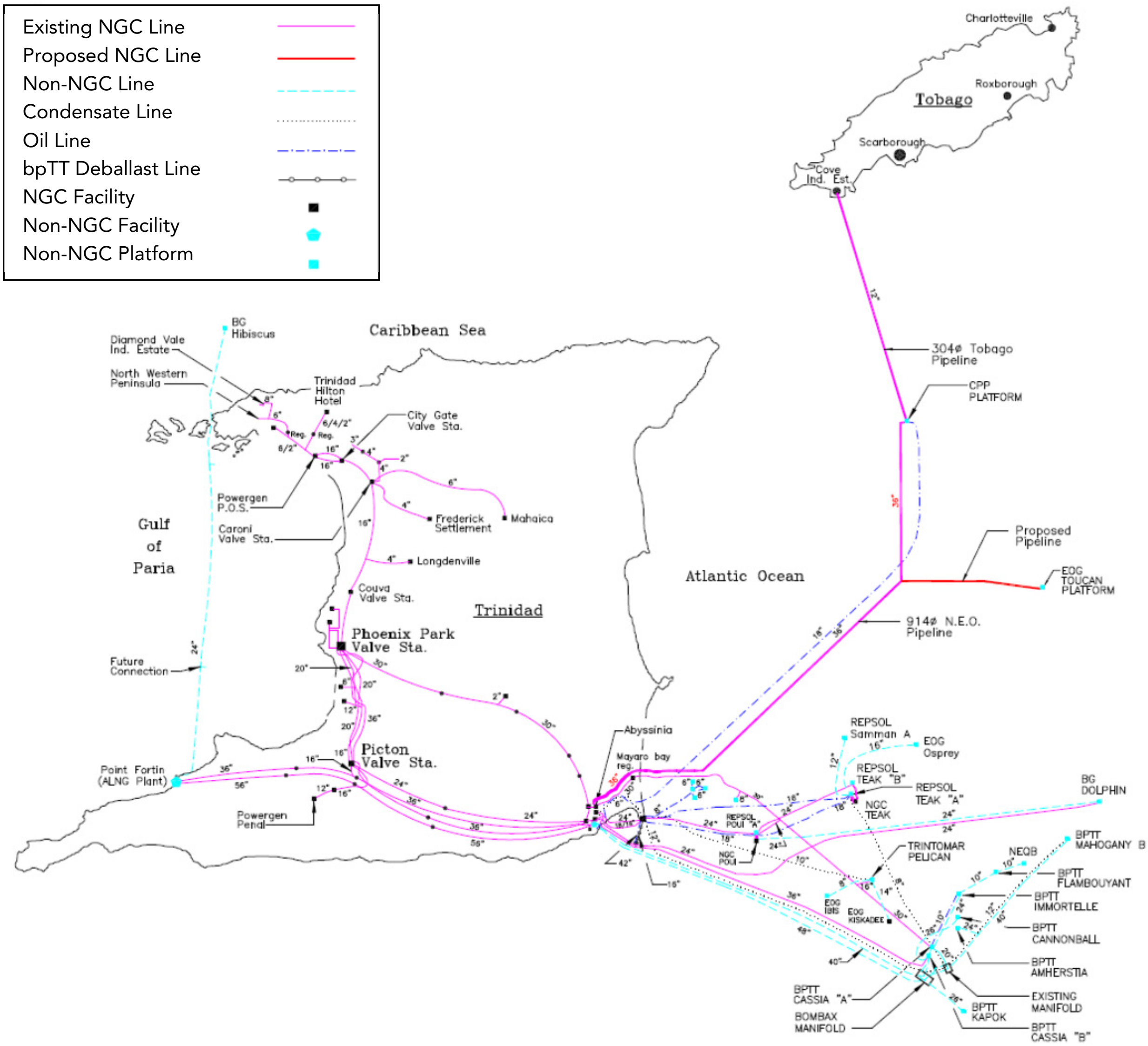
In the move to deeper water technology will be critical in reducing the finding and development costs associated with a large gas resource base, allowing a greater proportion of the reserves to be developed economically. There has been significant technological development in the Gulf of Mexico deepwater areas and elsewhere and T&T will need to utilise these technologies in the exploitation of deeper-water gas.

1.3 GAS TRANSPORTATION

There is an integrated network of offshore and onshore pipelines and processing facilities developed in T&T to ensure that gas can be transported effectively to the consumers. The gas transmission infrastructure installed in T&T is illustrated in the figure below:

Figure 1-6 T&T Gas Transmission Infrastructure

(source: NGC Data)



The gas pipeline system in Trinidad has evolved since the 1970's to be a major transmission and distribution system which consists of 6 major offshore pipelines 24", 30", 36", 56", 24" supplying Trinidad and a 12" to Tobago. Overall the gas transmission infrastructure has been sized with sufficient capacity to allow flexibility of supply across producing fields, with the exception of the NCMA Hibiscus pipeline which is running at design capacity.

1.4 CONTRACTING & GAS SUPPLY ARRANGEMENTS

1.4.1 Upstream License and PSC Arrangements

Given the commercial sensitivity of contractual arrangements, it was not possible to review the specific terms of all licenses and PSCs, however it was possible to review the provisions of the model PSCs for 2010, 2012 and 2013 2013 and a summary of terms for most shallow-water PSCs.

An unusual feature of the PSC terms is the relationship between the PSC and the petroleum regulations. The upstream portion of T&T's petroleum industry is regulated under a framework composed of the 1962 Petroleum Act and the Petroleum Regulations. The Act and Regulations are further supplemented by licences for exploration and production (EPL) and PSCs. The Act was revised by the addition of Section 6(4) when PSCs replaced EPLs as the method for granting exploration rights. This section allows the Minister to enter into PSCs that over-rule the application of the Act and Regulations. Rather than modify the Act, this structure allows the government to revise a broad range the terms and conditions through the model PSCs that are used for each bidding round.

GORTT receives a share of profit production under each PSC based on a 'matrix' that takes into consideration product prices as well as production levels. The increase in State participation under the PSC was offset by a provision that committed the Minister to pay royalties and other taxes assessed on PSC operations from his share of the profit petroleum. The ability for the Minister to influence upstream contractual arrangements for the sale and delivery of natural gas largely depends on the election made under Annex D of the PSC regarding the sale of GORTT's share of natural gas.

There are two noticeable issues with the procedure contained in Annex D. Firstly, the marketing plan presented to the Minister is prepared by the Contractor. Thus far the Minister has agreed to joint marketing as proposed by the marketing plans. Secondly, the commitment of GORTT's share of natural gas has not been subject to conditions that allow GORTT to influence how production is allocated between NGC and ALNG when there is insufficient gas available to fully satisfy both customers.

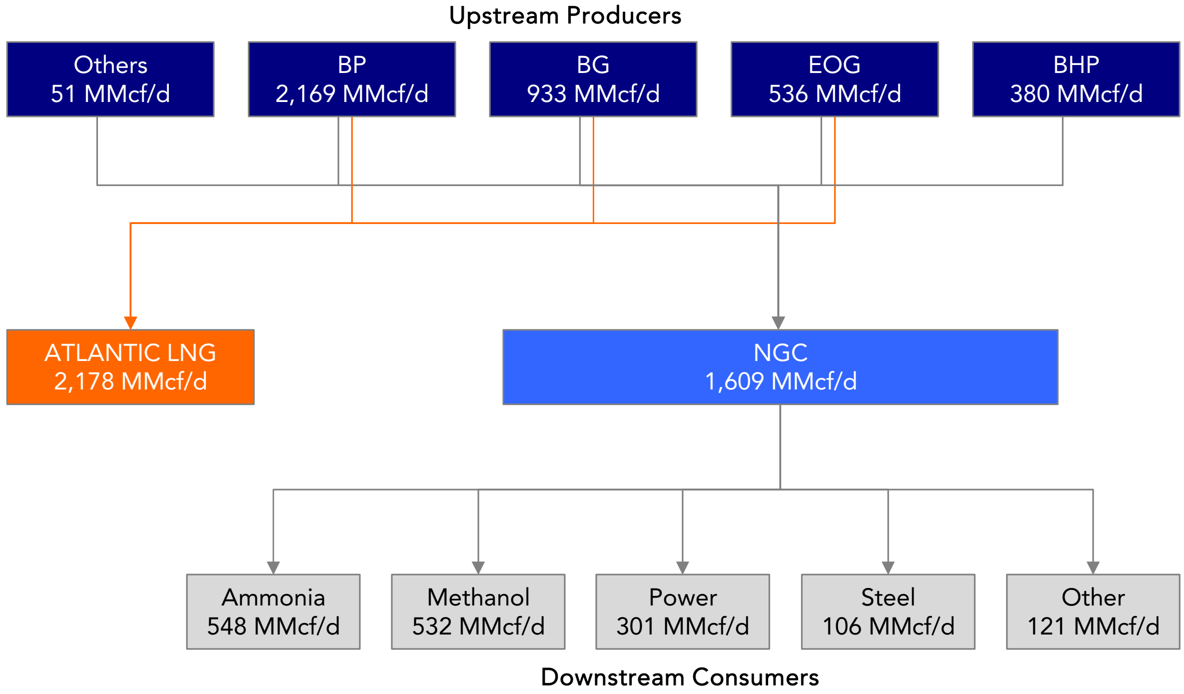
1.4.2 Gas Supply Contracting

Gas produced in T&T is supplied to either NGC or ALNG as illustrated in Figure 1-7 overleaf.

NGC currently contracts for around 2.1 Bcf/d of gas to supply the downstream sector in T&T through 11 contracts.

It should be noted that Poten only received very limited information about the contracts and was not provided with copies of the contracts themselves. Hence, we are not in a position to comment on specific contractual parameters or commitments. The contractual structures for gas supply to NGC were developed during a time of gas surfeit when flexibility in volume offtake was required to stimulate downstream industry. Since then the situation has changed to one of shortfall. We understand that while there are obligations in NGC's upstream contracts on the producers to meet supply commitments, in many cases there are no specific penalties for failing to do so. In most contracts we understand that there is the ability to bank gas that is not delivered (i.e. recover it at a later date), with a 5 year expiry term for banked gas.

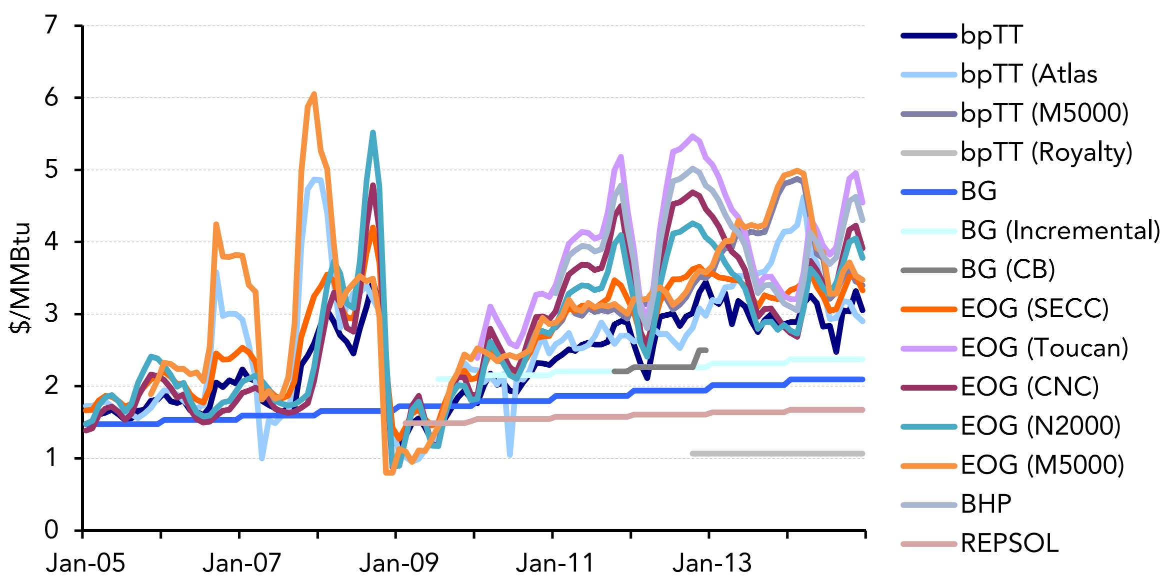
Figure 1-7 2014 Gas Supply Schematic



In general NGC acts as an aggregator and intermediary for gas supply to downstream consumers, and assumes any volume/price mismatch risk between its contracts for gas purchases and sales. However, under some upstream contracts tied to specific downstream plants NGC does not take volume risk, although it still acts as an intermediary; this risk is passed back directly between upstream supplier and downstream buyer. Examples of this are bpTT (Atlas methanol) and EOG (CNC/N2000 ammonia; M5000 methanol).

Figure 1-8 Historical Gas Pricing from Upstream Suppliers to NGC

(source: NGC)



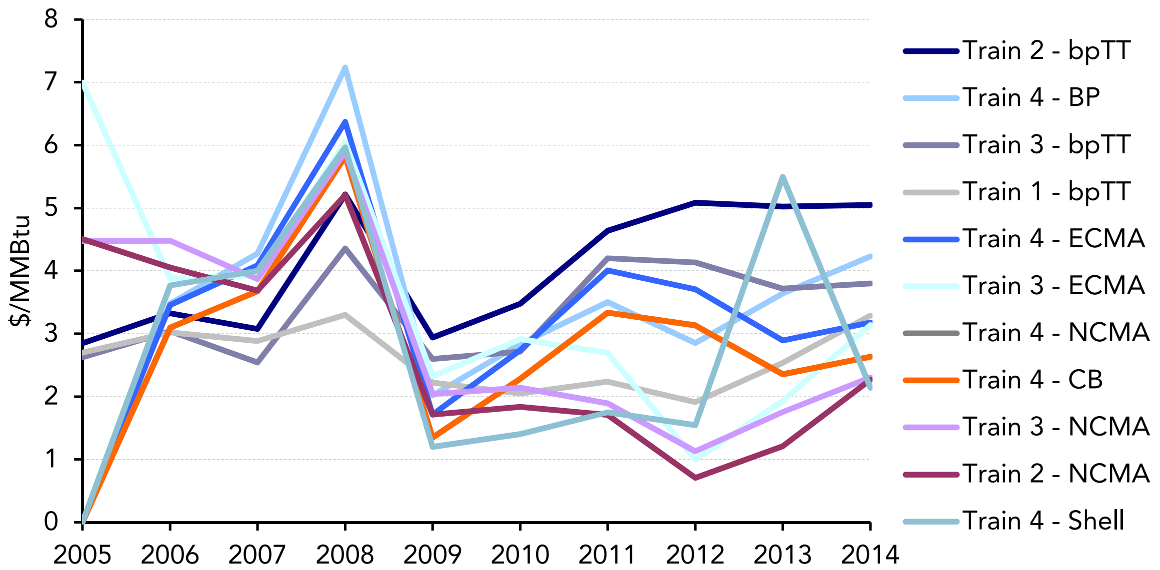
Much of the gas supply under the different contracts is priced based on end product markets (methanol, ammonia and US Henry Hub gas). The prices paid under the different contracts/traches are shown in Figure 1-8.

ALNG has contracts in place to supply an average of 1,410 MMcf/d to ALNG Trains 1-3. In addition, there are processing contracts in place with ALNG Train 4 (tolling facility) totalling an estimated 743 MMcf/d, which gives a combined “contracted” gas supply figure to ALNG of 2,153 MMcf/d. It should be noted that Poten only received high level summaries of both the gas supply and processing contracts, and therefore are not in a position to comment on specific contractual parameters or commitments.

The pricing realised by upstream producers for supply to LNG is linked to the LNG/NGL revenues realised from the gas supply. Hositorical realised pricing is shown in the figure below.

Figure 1-9 Historical Gas Pricing to Upstream Suppliers from ALNG

(source: ALNG, MEEA)



1.4.3 Security of Supply

The supply of gas to NGC has fallen short of the estimated contracted volumes since 2007 and in particular since early 2011. Declining supply from bpTT has at least partially been attributed to increased maintenance and asset integrity reviews in the period following the Macondo disaster in April 2010. BG supply has also suffered significant annual outages due to maintenance. Critically, total supply to NGC has been well below its total current supply contract volume of 2.25 Bcf/d. Shortfalls in contracted gas supply volumes to NGC have had a knock-on effect on the ability of NGC to meet its downstream gas supply commitments.

Figure 1-10 Estimated Historical Monthly Contracted & Delivered Gas Supply to NGC

(source: MEEA, NGC)

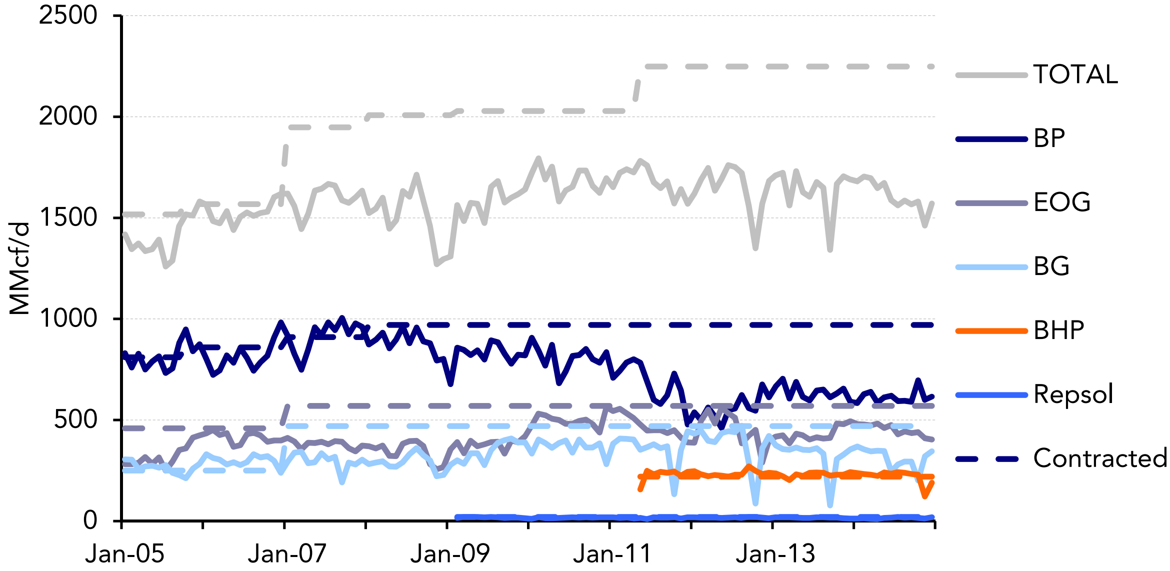
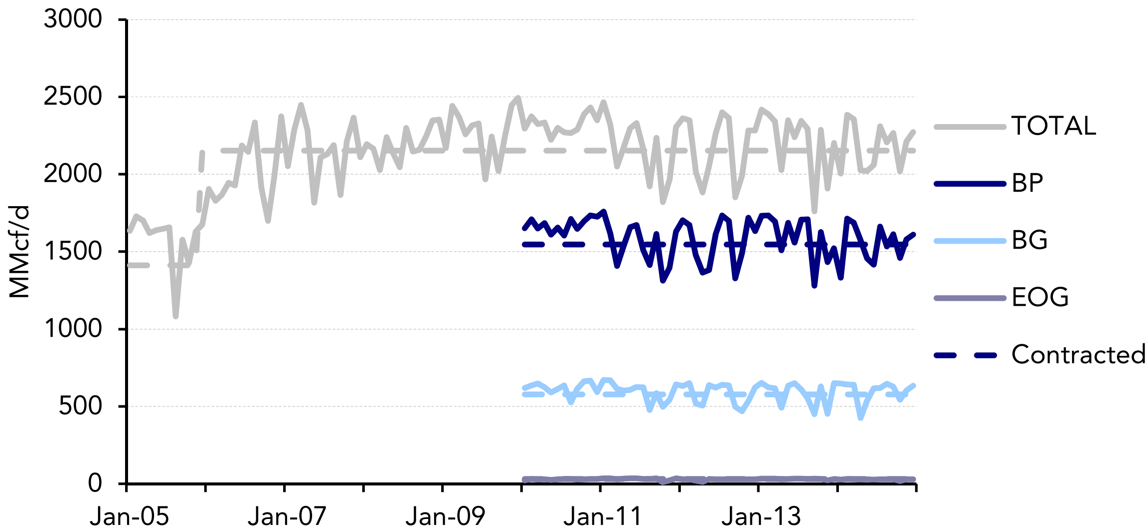


Figure 1-11 Estimated Historical Monthly Contracted & Delivered Gas Supply to ALNG

(source: MEEA, ALNG)



The relatively low exploration success in the last decade has resulted in a decline in deliverability of the producing gas reservoirs as larger fields deplete and increasingly small and marginal fields are brought onstream to fill the supply gap. The decline in available deliverability over recent years has led to increasingly frequent supply curtailments to both NGC and ALNG. Critically for NGC its average supply levels have been well below the contracted volumes, in contrast to ALNG where average supply levels have apparently been maintained at least at contractual commitment levels. Shortfalls in contracted gas supply volumes to NGC have had a knock-on effect on the ability of NGC to meet its downstream gas supply commitments, as is discussed in Section 1.11.

There is no requirement or financial incentive for suppliers to maintain excess deliverability (swing or cushion gas) which would allow them to compensate for supply reductions in other parts of the production system. As the gas system approaches the end of plateau production, deliverability will depend on depleted mature fields and an increasing number of small field developments which will typically have high depletion rates and limited excess deliverability. The vulnerability of the system to outages in individual fields will consequently tend increase over time.

Supply interruptions can be reduced by ensuring that there is sufficient deliverability in the gas production system to allow production to be increased to compensate for planned and unplanned shutdown of individual elements of the system. This can be addressed from two perspectives:

- A reduction in the magnitude and frequency of supply shortfalls caused by shutdowns of system elements.
- Increasing the available deliverability of the gas supply system.

Reducing the impact of shutdowns can be addressed to some extent by coordinated planning of maintenance programmes between producers to avoid too many production systems being off line for maintenance at any given time and we understand that efforts are being made to this effect by producers. However, the system will still be exposed to unplanned shutdowns. Increasing system deliverability requires investment, primarily in additional wells or field compression, given that gas treatment and transportation systems have demonstrated sufficient capacity in the past. This could take the form of accelerating current development plans to increase short-term production capacity before existing fields decline. Producers can be incentivised to do this by:

- Requiring excess deliverability in new supply contracts.
- Offering an additional tariff for maintaining reserve capacity.
- Paying a premium for gas supplied in excess of a company’s contractual requirement to compensate for shortfall by another supplier.

These measures risk being inefficiently prescriptive or open to manipulation. In general the production operator is best placed to determine the most efficient approach to maintaining reliable supply to the consumers within a framework of “Ship or Pay” terms in gas supply contracts which apply a penalty on the producer for failure to supply gas within the terms of the contract. As Poten has not been provided with specific details of the existing upstream supply contracts we are not in a position to comment on the extent to which “Ship or Pay” or equivalent terms are already contained in the contracts.

Poten has also been provided with limited information on a gas storage project which aims to compensate for short-term reductions in gas supply by producing gas stored in a depleted reservoir. Poten’s view is that the investment storage infrastructure would be better spent on increasing offshore deliverability to avoid the shortfall occurring. We are not aware of any other examples of where a gas storage project has been developed to cater for a largely export-based gas sector with a flat demand profile such as T&T. Delivery requirements under gas supply contracts are usually relied upon to ensure steady supply rather than external storage, as it is cheaper to have redundancy in supply infrastructure than in storage.

In all cases the supplier who fails to deliver gas and causes the shortfall to occur should bear some of the cost of measures taken to compensate for that shortfall, potentially through contract penalties. However the consumers must also accept that continuity of supply has a value that has not to date been reflected in the gas prices they have paid to date and that they must bear part of this cost in the future.

1.5 FISCAL COMPETITIVENESS

1.5.1 Current Fiscal Regime

The present fiscal regime utilises PSCs under which the GORTT receives a share of profit production after costs have been deducted. The allocation of profit production is determined by a ‘matrix’ that takes into consideration product prices as well as production levels. The increase in state-take under the PSCs compared to Production Licenses was offset by a provision that committed the Minister to pay royalties and other taxes assessed on PSC operations from the GORTT share of profit petroleum.

The speed of cost recovery is determined by a schedule that sets out the rate of amortisation and the proportion of annual revenue that can be allocated to the recovery of costs. In shallow-water areas exploration costs are expensed in the year that they are incurred. Early PSCs (1996-2005) depreciated development capital at 40% in the year following the expense, and 20% for the subsequent 3 years. In later PSCs (2011-12) development capital is expensed in the year that it is incurred. The proportion of revenue available for cost recovery is typically capped at 50-60% in shallow-water PSCs. The more recently awarded deepwater PSCs allowed development capital to be expensed in the year that is incurred and raised the ceiling on cost recovery to 80% of annual production.

There is a significant range of profit split terms in current PSCs. In general the contractor share of profit gas ranges from 15-30% at high production rates to 40-70% at low production rates. Variation within these ranges is driven by gas price and individual PSC terms. Early PSC (1996-2005) terms were linked to what are now unrealistically low gas prices ranges ($1-$3/Mcf) compared to more the gas price ranges in more recent PSC terms ($3-$7/Mcf). This has resulted in a two-tier system:

- Holders of older PSCs (1996-2002, 2005) are burdened by low contractor profit gas splits at even moderate gas prices by present standards.
- Holders of later PSCs (2011-12) and those without gas price indexing of profit splits (1974, 93) operate under terms intended by the original negotiation.

1.5.2 Government Take

A fundamental comparison among benchmark countries is the share of revenues that the investor will keep to cover costs and to provide for a return, compared to that taken by the host government. A comparison of government take was undertaken against a benchmark group of countries. These countries have been split in two categories: those applying a concession license regime and the others applying a PSC regime. T&T has both concession licenses and PSCs and so both are represented. A further delineation is made between early PSC (1996-2005) with terms linked to what are now unrealistically low gas prices ranges and more recent PSCs together with those without price indexing which are robust to market shifts in gas price in the last 5-10 years.

Analysis of the Government take, shown in Figure 1-12, demonstrates that PSCs in T&T which are robust to recent changes in gas pricing are competitive with the benchmark group. At $3/MMBtu gas prices span the range of competing concession terms and yield lower government take than benchmark PSC regimes. However, older, price-sensitive PSC terms are significantly less competitive.

However the government take is only one element of the competitiveness of the government regime. An overall assessment of the competitiveness of the T&T regime using the criteria of gas reserves, gas market accessibility, government take level and ease of doing business ranking was undertaken and an overall ranking has been developed for the benchmark countries. This is summarised in Table 1-1 below.

Figure 1-12 Range of "Government Take" in Benchmark Countries

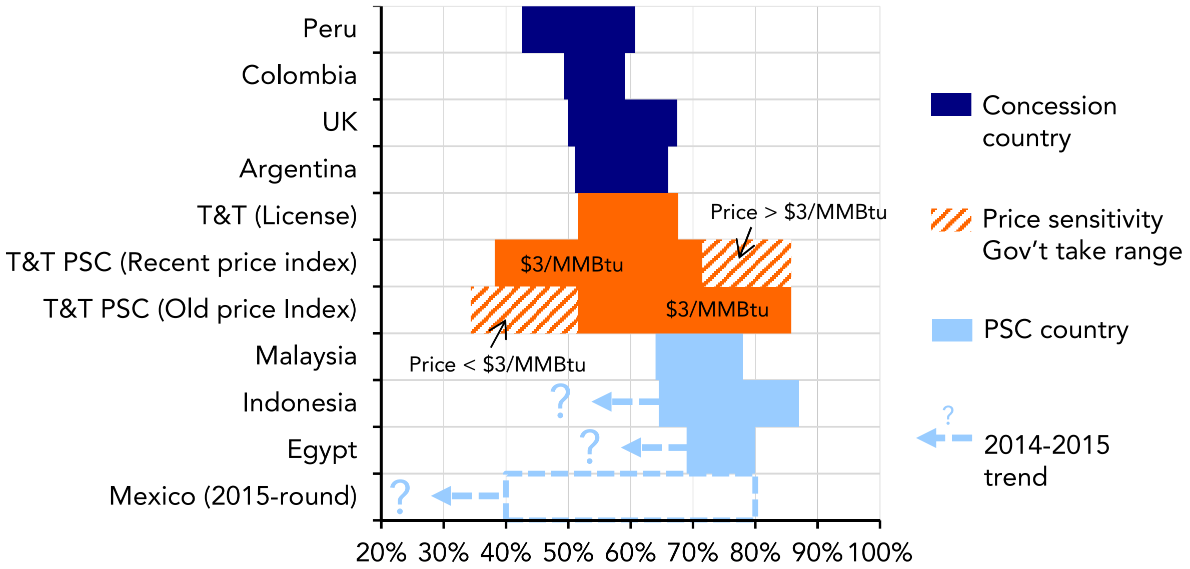


Table 1-1 Overall Ranking by Benchmark Country

COUNTRY	OVERALL RANKING	Ranking per criteria (out of 9): Proven Reserves	Market Accessibility	Gov't Take	Ease of Doing Business
Colombia	#1	5	2	2	3
UK	#2	8	1	3	1
Peru	#3	2	8	1	5
T&T (Price Robust PSC)	#4	7	9	1	2
Indonesia	#5	1	3	7	9
Malaysia	#6	4	6	6	4
Argentina	#7	6	5	4	7
T&T (Price Sensitive PSC)	#8	7	9	5	2
Egypt	#9	3	7	8	8
Mexico	TBC	9	4	TBC	6

T&T's price-robust PSCs with profit splits indexed to current gas prices or without price indexing at all are ranked in fourth place, leading the countries where PSCs were implemented; but still lagging behind countries that have implemented concession licences. However older price-sensitive PSCs linked to gas prices below current levels rank second to last within the benchmark group, highlighting the fact that an incumbent under price-sensitive PSC terms faces a greater hurdle to invest in T&T to sustain production compared to opportunities elsewhere. T&T's production license terms deliver similar economic results to the older price-sensitive PSC terms. The analysis indicates that improvements in fiscal terms and gas market accessibility may be required to attract preferential investment in T&T. This would be particularly the case for incumbents under old PSCs and license terms who have to invest to maintain production.

1.6 RESERVES & PRODUCTION OUTLOOK

1.6.1 T&T Reserves Base

MEEA commissions a reserves report for all national acreage annually; the most recent report by Ryder Scott details reserves and resources as at 31 December 2013. This report provides a comprehensive statement of estimated remaining reserves and prospective resources, risking factors for these volumes and indicative production profiles for each field. T&T's proven natural gas reserves totalled 12.2 Tcf at end 2013. These reserves consist mainly of non-associated gas and as such the potential production restrictions of gas associated with oil production are limited. The analysis from the most recent Ryder Scott reserves report commissioned by MEEA is shown in Table 1-2 and Table 1-3.

Table 1-2 T&T Unrisked Gross Reserves at December 2013

(Source: Ryder Scott)

Category	Gas (Bcf)	Condensate (bbl)	NGL (bbl)
Proven Reserves	12.240	41,012,953	44.119,615
Probable Reserves	5,526	22,880,305	21,377,993
Possible Reserves	6,116	32,175,419	24,236,007
Total	23,881	96,068,677	89,733,615
Identified Exploration Resources	39,867	112,448,469	188,281,911
Total	63,748	208,517,146	278,015,526

Table 1-3 T&T Unrisked Gas Reserves (Bcf) by Company at December 2013

(Source: Ryder Scott)

Company	Proven	Probable	Possible	Sub-Total	Identified Exploration Resources	Total
bpTT	6,728	2,969	2,881	12,578	5,597	18,175
BG	2,388	1,159	2,099	5,646	8,546	14,191
BHP	526	243	156	924	668	1,592
Chevron	1,186	382	-	1,568	-	1,568
EOG	754	269	342	1,366	2,152	3,518
Centrica	618	498	397	1,512	5,415	6,927
Repsol	41	7	-	48	-	48
Niko	-	-	-	-	8,292	8,292
Open Areas	-	-	240	240	9,198	9,438
Total	12,240	5,526	6,116	23,881	39,867	63,748

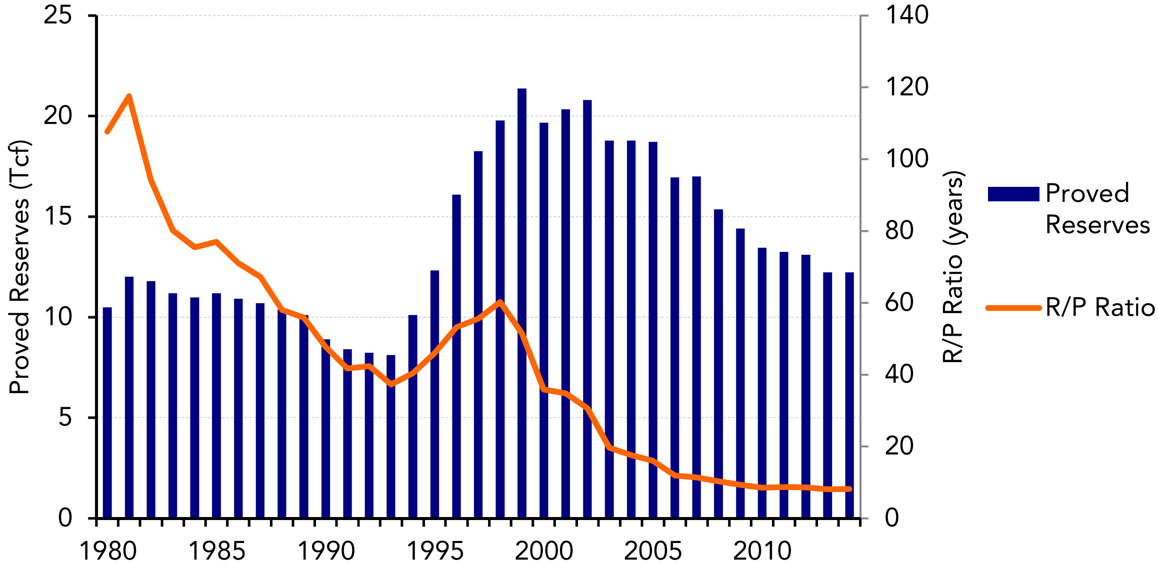
The proven reserves make up 51% of the unrisked reserve distribution, with 23% in the probable category and 26% in the possible category. The largest resources are held by bpTT who hold 55% of the unrisked reserve base, followed by BG with 20% - so three quarters of the country's reserves are in the hands of these two companies. It should be noted that in this table the volumes held by Chevron relate to T&T equity reserves in the cross-border fields with Venezuela, which will not be readily available until a cross-border field development plan is put in place. Without the Chevron reserves the unrisked proven reserves would be ~11.1 Tcf.

1.6.2 Reserves Base Evolution

The total proven natural gas reserves in T&T have been in decline over the last decade as the rate of reserves additions has failed to keep pace with production. Proven reserves peaked in 2002 at approximately 20.8 Tcf. During 2003 and 2004 there was almost 100% reserves replacement but by 2006 proven reserves had dropped to 17 Tcf. The decline since has fluctuated year on year but by the end of 2013 proven reserves had dropped 41% from the 2002 peak.

Figure 1-13 T&T Reserves Evolution

(Source: BP Statistical Review of World Energy 2015)



The ratio of reserves to production (R/P) provides a measure of the sufficiency of reserves to maintain production over the long term. Based on Ryder Scott data, as of end-2013, proven (1P) R/P ratio was 8.3 years and the Proven + Probable (2P) R/P ratio was 12.1 years. The BP Statistical Review of World Energy gives a proven (1P) R/P ratio of 8.2 years as of the end of 2014. However, due to the natural decline in deliverability of the gas fields as reserves are depleted, gas production will fall below the ~1.62 Tcf/y plateau demand level significantly earlier than the ~8-11 year durations implied by these ratios, even if such a plateau rate could be achieved.

The Ryder Scott Report presents Proven, Probable and Possible reserves for all discovered fields together with a Risk Factor for each reserves category. Each reserves category in each field is multiplied by the Risk Factor to provide Risked Profiles, the sum of which are presented as a mean production profile for the portfolio. The graphs below present raw profiles from the Ryder Scott report and an adjustment of the profiles to align with the available gas market in T&T.

Figure 1-14 Ryder Scott Risked Reserves and Prospective Resource Profile

(Source: Ryder Scott)

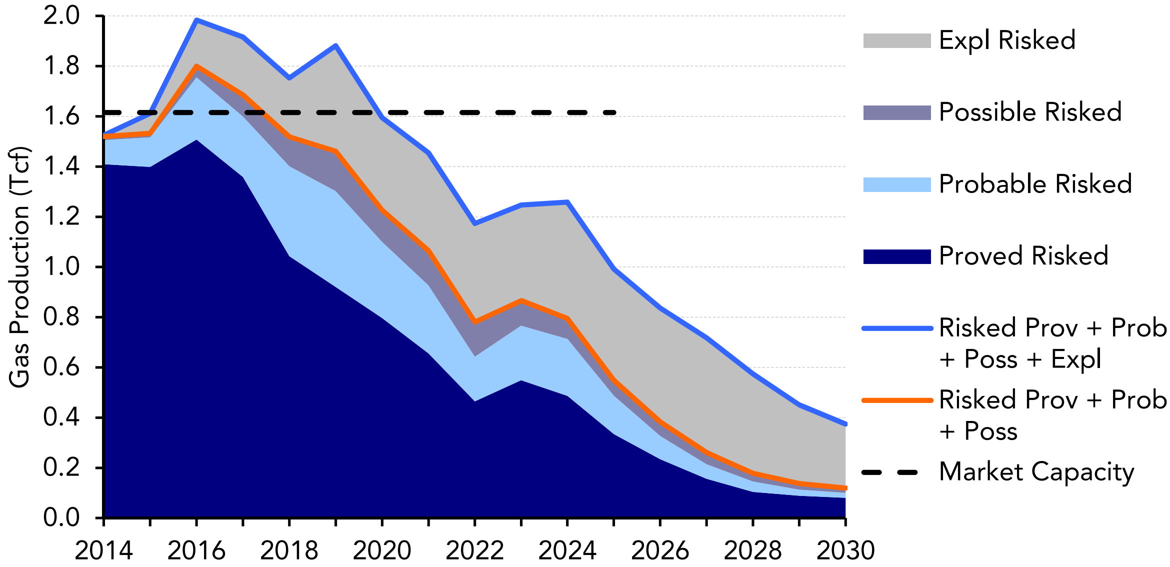
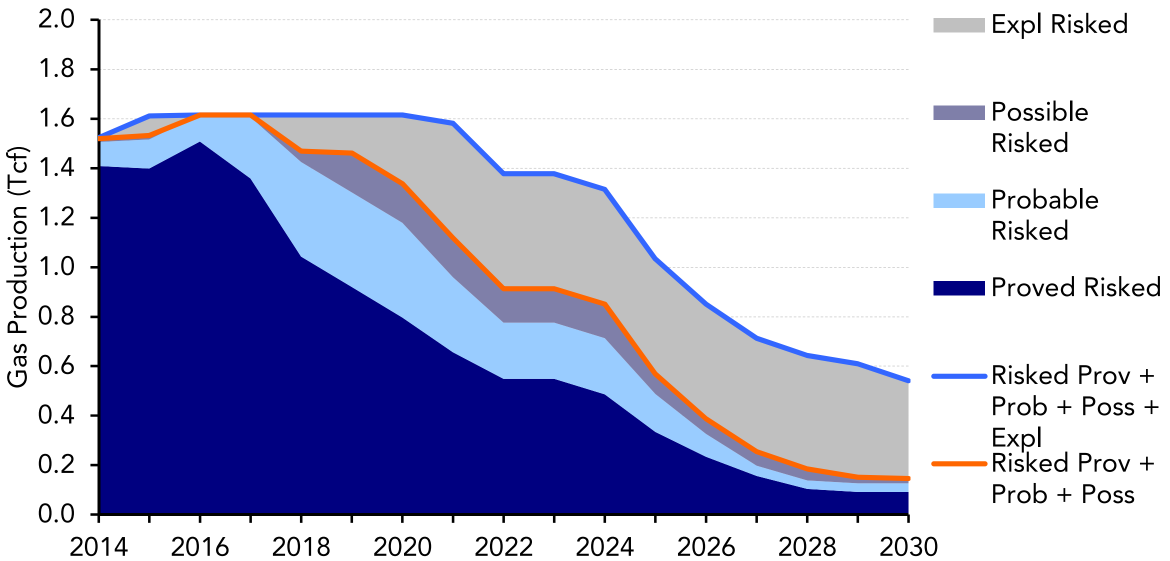


Figure 1-14 plots the risked (expected) gas profile from the Ryder Scott report, showing the contributions from Proven, Probable, Possible and Prospective resource categories from all the fields assessed by Ryder Scott. The technically possible gas production depicted in this figure is unconstrained by market capacity and assumes that all field development plans will be sanctioned by the operators.

Figure 1-15 Ryder Scott Risked Reserves and Prospective Resource Profile Constrained to Market Demand of 1.62 Tcf/y

(source: Ryder Scott)



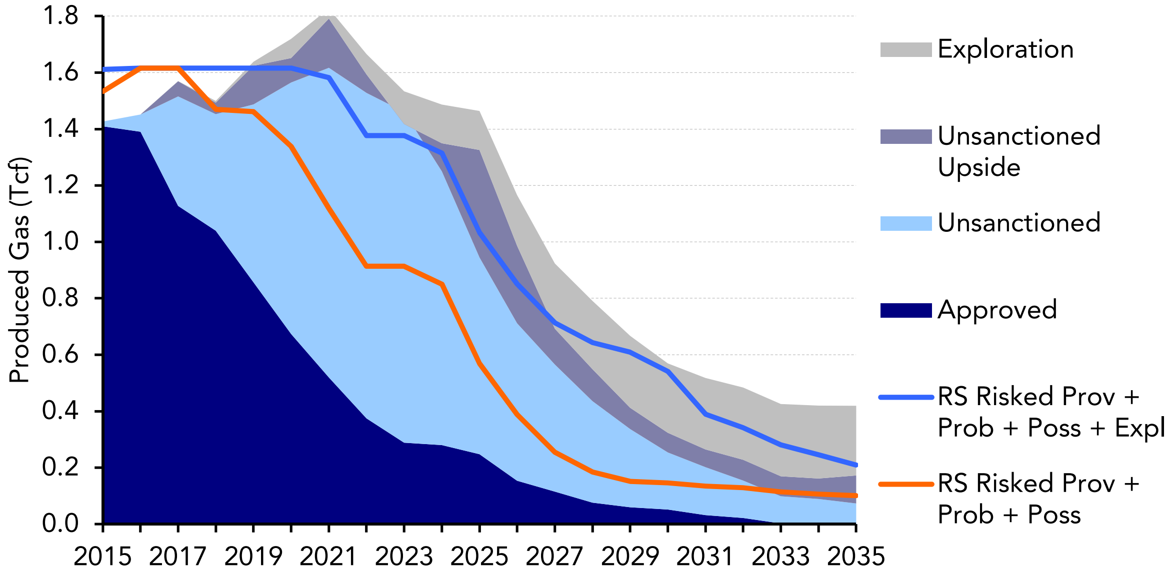
Poten has reviewed the historical consumption of gas in T&T through ALNG and NGC and matched this with gas production records provided by MEAA. This data suggests a maximum average demand of 4,423 MMcf/d or 1.616 Tcf/yr including shrinkage. The impact of constraining production to this level is illustrated in Figure 1-15. By deferring gas production from early years where production potential exceeds demand, the production plateau is extended and the initial rate of decline from plateau is reduced.

1.6.3 Operator Production Forecasts

The major operators have provided forward production forecasts as input the Gas Master Plan. These have been combined with assumptions on the profile of the remaining 5% of production based on historical decline and Ryder Scott forecasts to develop a forward production profile driven by the operators' business plans. The result of this analysis is presented in the graphic below, with the operator driven forecasts presented as solid areas and the previously derived levelled Ryder Scott profiles as lines for comparison.

Figure 1-16 Forecast Production from Operator Business Plans and Ryder Scott Risked Profiles

(source: Ryder Scott, bpTT, BGTT, EOG, Repsol, BHP, Centrica)



The profiles presented in this section are limited to shallow-water developments planned by operators and exclude potential deepwater supply and potential production from cross-border fields subject to negotiation with Venezuela.

Several conclusions can be drawn from this analysis:

1) The operator production profiles fall short of the potential demand of the ALNG plant and existing industries supplied by NGC.
2) The operator production profiles rely heavily on unsanctioned projects which will only be realized if they pass operator economic screening hurdles and proceed into execution.
3) Overall the operators have plans to develop gas volumes in excess of the risked mean presented in the Ryder Scott reserves report.

The shortfall in production compared to the current demand presents the most immediate concern for the T&T gas industry. The production level that can be relied upon for the remainder of the plateau period is dependent primarily on approval of unsanctioned projects and, towards the plateau end, on exploration success. Given that not all unsanctioned projects will progress on time, a forecast production of 1.4 Tcf/y (circa 3.85 Bcf/day) is a reasonable planning basis allowing for upside and exploration success to offset unsanctioned project delays.

The heavy reliance of the forecast profile on unsanctioned projects post 2017 emphasizes the importance of operator decision making processes to GORTT. Within five years more than half of the forecast production is expected to come from projects that have not yet been sanctioned by the operators and joint venture partners. Any delay in sanction of the incremental developments providing these gas volumes will cause a decline in short term production levels. Given that these developments are targeting discovered volumes the decision making will be driven primarily by the economics of the incremental developments, which in turn is driven primarily by executioncosts, gas prices and fiscal terms.

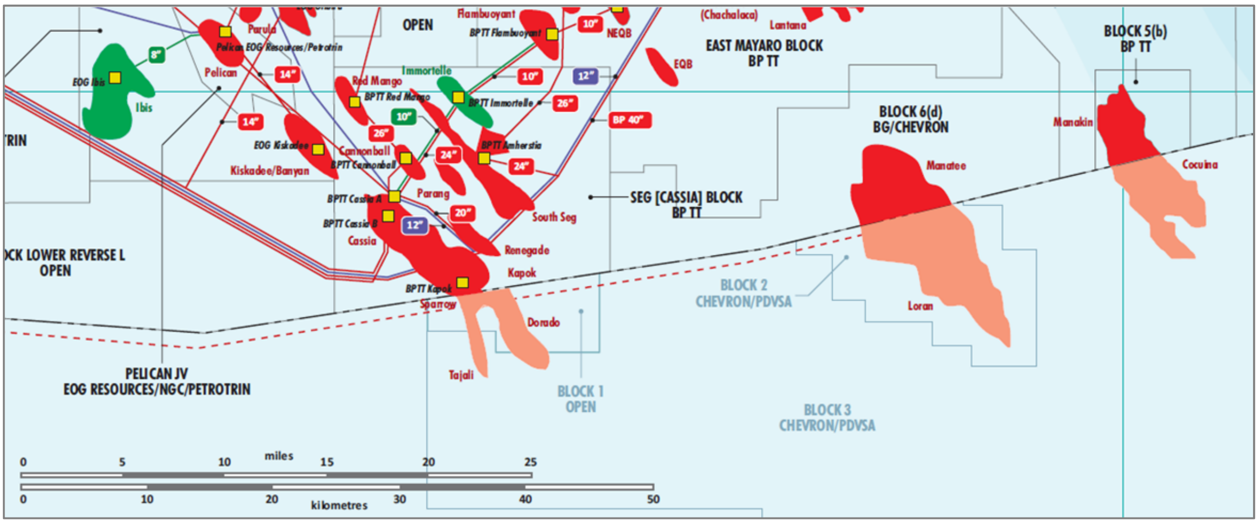
1.6.4 Cross-Border Gas

Gas from fields that straddle the T&T/Venezuela border have the potential to provide incremental supply to T&T, in particular if both T&T and Venezuelan equity gas is monetised through T&T. The fields are relatively close to existing T&T production locations and infrastructure. They are distant from the Venezuelan coast on which there exists no gas infrastructure with which to monetise the resources.

There are three discovered gas fields that span the marine border with Venezuela; the Loran–Manatee gas field, the Manakin–Cocuina gas field and the Kapok – Dorado gas field. By far the largest field is the Manatee Loran field containing up to 7,175 Bcf of gas. The Manakin Cocuina field is relatively small and will not have a significant impact on the country's overall gas supply position and the Kapok Dorado field is already in production by bpTT, the operator.

Figure 1-17 Cross-Border Field Locations

(Source: Petroleum Economist)



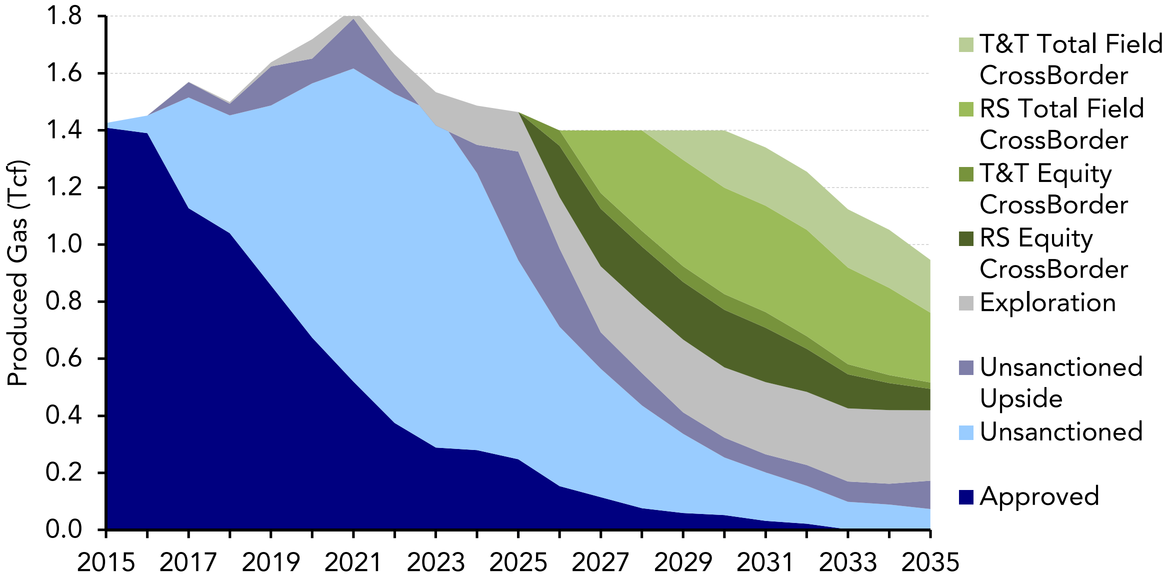
There are two identified sources of reserve estimates for these fields, the Ryder Scott reserves report estimates the recoverable volumes within T&T's boundaries and a Cross-Border Status Report tabulates the volume estimates reported by the Joint Working Group (JWG) established by the governments of Venezuela and T&T. Application of the percentage splits carried by the JWG to the Ryder Scott estimate of T&T reserves allows back calculation of total field volumes. Volume estimates from these two data sources are presented below.

Table 1-4 Cross-Border Gas Volume Estimates
(Source: MEEA and Ryder Scott)

Field	T&T Share	Estimate Source	T&T Recoverable Gas (Bcf)	Total Field Recoverable Gas (Bcf)
Manatee Loran	26.94%	JWG	1,933	7,175
		Ryder Scott	1,434	5,323
Manakin Cocuina	66%	JWG	429	650
		Ryder Scott	263	398
Kapok Dorado	84.10%	JWG	264	314
		Ryder Scott	725	862

In order to illustrate the potential impact on T&T's gas supply profile we have assumed gas production begins in 2026. This allows several years for inter-governmental agreements to be executed as well as a timeline of circa 5 years for a project of this magnitude to pass through FEED, reach Final Investment Decision by the venture partners and also be executed. This timing also coincides with the availability of significant ullage capacity in T&T's gas processing infrastructure.

Figure 1-18 Impact of Cross-Border Gas Scenarios on Production Profile
(Source: MEEA, Ryder Scott, bpTT, BGTT, EOG, Repsol, BHP, Centrica)



The resultant gas profiles are presented in Figure 1-18. In each case it is assumed that no more than 11% of field reserves would be produced in any one year to allow responsible management of field depletion and avoid over investment in production infrastructure. This results in a production plateau of circa 6 years followed by a circa 7 year decline which may be considered aggressive, depending on evaluation of the reservoir performance.

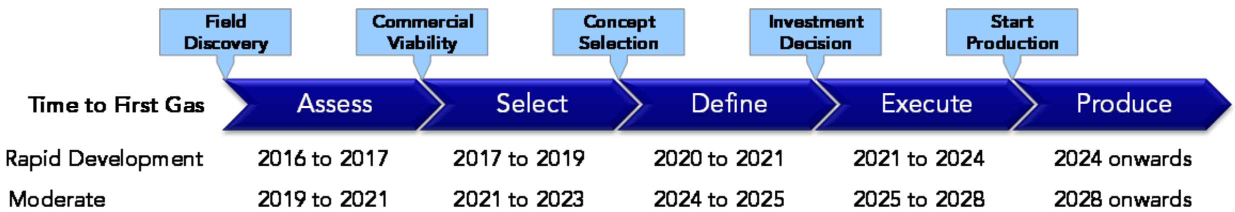
It is clear that for cross-border gas to make a major contribution to maintaining the production plateau it would require all of the cross-border gas to be monetised in T&T. The T&T share, while helpful in slowing decline will do little to extend the plateau. A priority for GORTT will therefore be to work with Venezuela to find ways that both countries benefit through delivery of the cross-border gas to T&T. As there would be significant avoided cost for Venezuela in monetising the gas through existing plants in T&T there should be scope for reaching an arrangement that benefits all parties.

1.6.5 Deepwater Gas Supply

The deepwater offshore area is considered to have significant hydrocarbon potential although any realisation of this potential will take some time and at best would provide gas at the end of this Master Plan period. Exploration work is only just beginning on the deepwater blocks and the initial exploration programmes extend to around 2022. The commercialisation timeline for deepwater acreage is significant; given the exploration timeline, early appraisal and assessment of commercial potential is unlikely to be complete for a deepwater discovery before 2020.

We have considered two possible schedules, one based on rapid development of a clearly commercial discovery made early in a 2016 drilling campaign and on the basis that further appraisal drilling and seismic can be completed in parallel with early development planning. A second more moderate schedule reflects further iteration and optimisation of the development plan before sanction to execute.

Figure 1-19 Deepwater Development Timeline



A notional discovery of circa 3,000 Bcf could sustain a production plateau of 1 Bscf/d for about 5 years before slipping into decline as the field is depleted. To maintain the current plateau rates in the absence of cross-border gas supplied by the shallow fields, two such developments would be required by 2026 and 2027, followed by a third in 2029. This would be an impressive run of discoveries from a frontier exploration area. Discovery of fewer or smaller fields would reduce the contribution to maintaining the plateau accordingly.

A combination of moderate deepwater success and some gas production from cross-border fields would provide some support to extend plateau or reduce the rate of production decline post-2025. If there has been no deepwater exploration success by 2018 or significant progress in cross-border discussions with Venezuela by 2020 then the industry should prepare for a further decline in long-term gas supply levels.

1.7 MOBILISING PRODUCTION

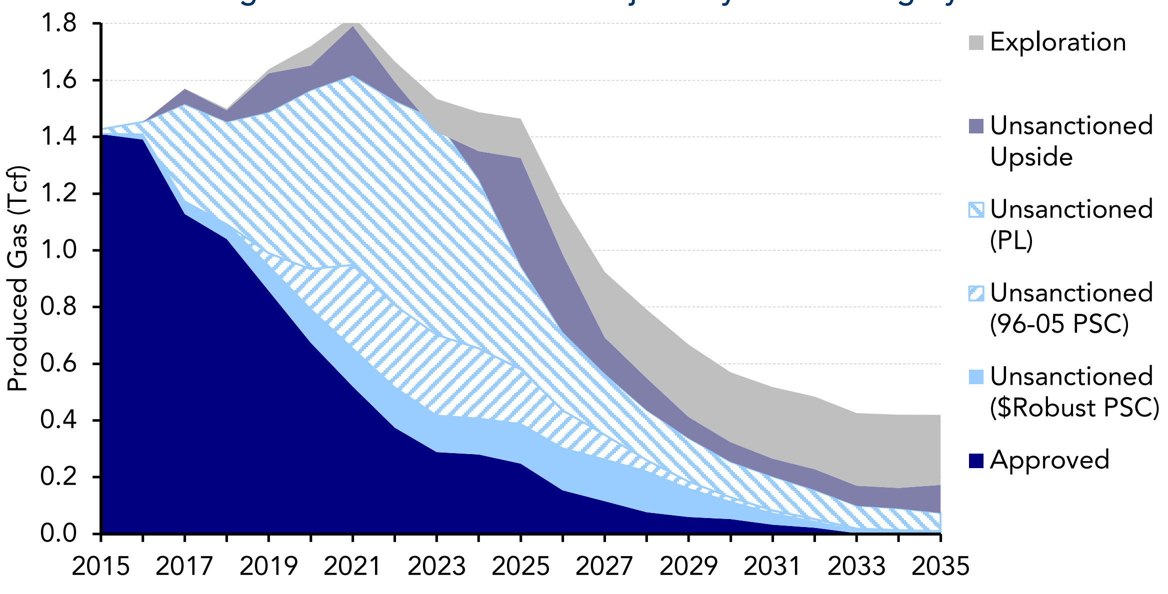
1.7.1 Shallow-Water Projects

The analysis of production profile projections identified that a significant proportion of gas volumes supporting the current production plateau beyond 2017 were reliant on planned but as yet unsanctioned projects being sanctioned and executed by the operators on their currently envisaged timelines. This requires that the as yet unsanctioned projects meet JV economic screening hurdles without any significant delay to ensure production commences within the anticipated schedule.

The capital cost of development plays a significant role in determining the economic attractiveness of a project seeking approval for execution. Projects utilising existing brownfield infrastructure will have a considerable economic advantage due to the lower capital cost incurred. Maximising the access to ullage in existing facilities will expand the proportion of new developments which can enjoy this advantage.

Analysis of the economics of incremental projects suggests that 1996-2005 PSC terms with gas price indexing of profit gas splits will not support sanction of many of the developments required to maintain plateau production in the coming years. It also identified that existing production license terms would similarly struggle to support many new developments. These conclusions are based on assessment of generic development concepts with normalised license and PSC terms and while they are therefore not conclusive, it does provide some insight to the proportion of unsanctioned projects likely to proceed on their planned schedule. The proportion of unsanctioned projects which fall into these categories is illustrated in Figure 1-20.

Figure 1-20 Unsanctioned Projects by Fiscal Category



The analysis indicates that the distribution of projects required to support plateau production post 2017 can be categorized as follows:

- 66% are located in production license areas which will require adjustment of both fiscal terms and gas prices to support the full spectrum of likely gas developments.

- 18% are located in 1996-05 PSCs with profit gas splits set in a low gas price environment which will require adjustment of both fiscal terms and gas prices to support the full spectrum of likely gas developments.
- 16% are located in PSC's with terms that are robust to current gas prices and which could reach economic screening hurdles with moderate flexibility on gas prices for developments carrying significant new infrastructure.

Regulatory intervention to stimulate marginal field development is not new to the oil and gas industry and many examples are available from other regions. In general the measures fall into three categories, summarised in Table 1-5.

Table 1-5 Marginal Field Support Approaches

Option	Mechanism	Pros	Cons
Strictly Impose Relinquishment	Strictly apply relinquishment clauses. Refuse extensive appraisal periods. Re-bid to give low cost operators access to resources	Leverages existing contract terms Allows lower cost producers to access marginal acreage	Confrontational: State needs to collaborate with operators to manage gas supply State needs ability to manage total production – may need some gas deferral
Negotiated Support	Create a mechanism in which operators can request concessions on fiscal terms and gas pricing to allow projects to meet a defined commercial hurdle	Assistance is only provided to projects that need it and at the level required by the project	State needs capacity to analyse projects and negotiate with operators Potential for inconsistent treatment and gaming by operators
Marginal Field Fiscal Terms	Define category of fields which can access tax breaks / higher share of profit production	Provides clarity on incentives available and a consistent approach Low implementation burden on State	"Marginal field" difficult to define Step change in fiscal terms for marginal fields will encourage gaming by operators

The objective of marginal field intervention is to ensure that gas plateau production is extended as long as commercially reasonable and technically possible to maximise upstream revenue and support the downstream gas consuming industries. This requires both incentivisation of marginal fields and penalties for behaviours that do not support the production plateau on a basis that is transparent to all stakeholders.

Transparency requires a clearly defined and balanced environment for development of hydrocarbon resources, however the complexity of the mature shallow-water areas offshore T&T make application of a strictly formulaic approach problematic. An attempt to define which developments should receive marginal field incentives based purely on project characteristics will be challenged by the impact of brownfield infrastructure access and other project specific factors which influence economics. Similarly automatic and strict application of relinquishment terms may run counter to those objectives. However, to enhance transparency of the sector the default position of the regulator should be to enforce relinquishment terms unless specific arguments supporting short-term gas supply can be made to the contrary.

Maintenance of a plateau production rate of 1.4 Tcf/yr (3.85 Bcf/d) requires that a significant majority of unsanctioned projects proceed as planned. The analysis would support a hybrid approach to this goal, consisting of an initial realignment of fiscal and other regulations to reflect maturation of the industry that has occurred over the last decade, combined with flexibility for the regulator to provide support to specific developments that cannot progress even under the revised terms

The initial re-alignment of regulations should include:

- Maximising access for new developments to existing infrastructure to reduce costs.
- Review and updating of fiscal terms in 1996-05 gas price indexed PSCs.
- Review and updating of fiscal terms in in production license areas.

A transparent and easily administrated approach will also be required to the application of incentives for fields that remain marginal covering both additional fiscal support and flexibility in offered gas prices.

1.7.2 Access to Infrastructure

Access to existing transportation infrastructure, transportation lines, platform and gas processing facilities can have a significant impact upon new projects economics and in some cases can be the critical factor in ensuring economic viability.

There are two criteria which must be met for a project to take advantage of existing infrastructure. Firstly sharing of infrastructure must be technically viable, including consideration of the required and available capacity of the infrastructure and compatibility of the produced fluids with the infrastructure design and existing hydrocarbon flows in the system. Secondly there must be mutually acceptable commercial terms agreed between the owner/operator of the infrastructure and the owner/operator of the project wishing to use that infrastructure.

Our discussions with operators have indicated that there is demand for greater access by developers to third party infrastructure which will only increase as development of the shallow-water area continues to mature. The discoveries in NCMA 4 of the Orchid and Iris fields are struggling to move into development, partly due to their isolation from capacity in existing infrastructure, in this case constrained by an inability to secure capacity in BG's Hibiscus line and the low technical capacity of the NGC line from Tobago. In addition, the existing pipeline networks cross a significant number of open acreage blocks. Interest in exploring these areas would be increased if there was greater clarity on the terms of access to existing infrastructure in the event that exploration of those areas proves successful.

The challenge for the regulator is to create the conditions in which spare capacity in existing upstream infrastructure is made available to other developers under reasonable commercial terms to stimulate exploration and production investment. Approaches to this issue have been applied in other hydrocarbon producing countries, in particular Indonesia and UK North Sea. The options available to the regulator fall in to three broad categories summarised in Table 1-6, together with their pros and cons.

Table 1-6 Approaches to Improving Infrastructure Access

Option	Mechanism	Pros	Cons
Code of practice: voluntary – not legally binding (UK N Sea)	Owners publish tariffs and key terms and conditions Shippers negotiate with owners, but can apply to GORTT for a ruling if no agreement reached with owners	Can cover platforms and pipelines No legislation required Low cost approach	Needs clarity on coverage Protracted negotiations MEEA needs capacity to make rulings Smaller companies can face difficulties meeting larger company demands
Regulate access to infrastructure (Indonesia)	Legislate commercial terms for access to infrastructure by third parties. Access to all cost recovered infrastructure is on a shared opex basis	Simple and clearly consistent approach Maximises use of existing infrastructure	Would require a significant change to existing agreements to increase political risk. May discourage installation of additional infrastructure
Transfer infrastructure to common carrier	Pipeline operation regulated by State Carriers allocates and expands capacity	Clear set of rules and tariffs	Only suitable for pipelines Significant upfront cost and work required to establish system and operations Requires new legal/regulatory regime

The success of the relatively unintrusive UK North Sea approach of an Industry Code of Practise, supported by a regulator willing to intervene in the national interest in exceptional circumstances, presents a compelling model for T&T. The similarities in basin maturity and active operators to the North Sea, the need for a rapid (and therefore legally simple) solution and the desire to avoid perceptions of political risk by radically rewriting existing arrangements all support this conclusion.

1.7.3 Modifications to PSC Fiscal Terms

Three broad approaches to modifying fiscal terms have been identified in Table 1-7. The approaches are graded by the extent of intervention required by the regulator and of the changes required to contractual terms. The boundary between minimal and moderate intervention is grey, moderate intervention is characterised by taking some proactive action on fiscal terms to reduce the number of projects which must be reviewed for a decision on case by case fiscal support.

Preliminary analysis suggests that revision of existing 1996-05 PSCs with gas price indexing of profit-split matrices, by revising the profit-split matrix gas price bands to a range of \$3.00/Mcf to \$7.00/Mcf will provide a necessary boost for incremental / brownfield development projects at moderate impact to GORTT revenue. Offering these terms for new and incremental developments in the affected blocks is a good candidate for proactive adjustment of fiscal terms, moving the recommended response at least into the moderate intervention band.

Table 1-7 Approaches to Modifying Fiscal Terms

Option	Mechanism	Pros	Cons
Minimal Intervention	Only review fiscal terms where operator requests relief to support development	Minimises number of permits subject to fiscal changes. Avoids unnecessarily reducing GORTT take	Requires MEEA to review many requests for support: potential for delay. Inconsistent treatment of permits and operators
Moderate Intervention	Revise terms clearly incompatible with current industry environment e.g. PSC profit split pricing bands reset to current pricing levels	Simple (rapid), improves consistency of terms across shallow-water area Leaves split percentages bid by operators in place, preserving intent of bidders	May unnecessarily reduce GORTT take in some projects
Deep Intervention	Revise all PSC and license terms to a new common basis	Ensures all reserves have an equal fiscal basis for development	Wholesale change may be challenged by incumbents Eliminates basis on which permit was won

A more detailed review of planned projects should be undertaken to determine whether relaxation of PSC cost-recovery terms should be included in this proactive step or applied only under negotiation of specific developments. The need for support of projects under existing license terms is also clear, but again further review of planned projects would be required to recommend the support that should be offered proactively across all license areas, rather than on a case-by-case basis.

The need for a rapid (and therefore legally simple) solution and the desire to avoid perceptions of sovereign risk by radically rewriting existing arrangements suggest that wholesale change to fiscal terms in a deep intervention approach would not be appropriate.

The moderate intervention approach will require transparent definition of the support available through negotiation with the regulator to encourage developments which otherwise will not meet economic screening hurdles. Such support would include:

- Depreciation schedules in both licenses and PSCs and cost-recovery caps in PSCs.
- In PSCs with existing production consider ring-fencing production from incremental projects to improve contractor profit gas splits which maintain shared cost recovery.
- In production licenses consider applying tax breaks similar to those available for deepwater developments.
- Allocation of preferential gas prices to marginal developments.

The requirement to actively support marginal projects through the sanction process by allocating fiscal relief and / or preferential gas prices where they are required by each individual project will place a significant burden on the regulator. Currently the regulator has been required to implement only a single set of fiscal terms for each permit and has been able to operate largely separately from the gas price negotiations managed by NGC. The challenge for the regulator will be to apply additional support only to those projects that need them, in collaboration with gas price negotiations by NGC and in a timeframe which does not delay the orderly sanction and execution of gas supply projects required to maintain plateau production.

1.7.4 Mobilising Cross-Border Gas

Supply from the cross-border fields relies on the outcome of government to government discussions which have been in progress for many years. Only 27% of the largest field (Manatee Loran) lies in T&T waters but for any significant extension of plateau production the entire field would need to be processed through T&T infrastructure.

The challenge therefore is two-fold:

- Stimulate progress in the long running inter-government discussions.
- Incentivise Venezuela to develop the entire field through existing T&T infrastructure.

Progress over the years has been slow and politically contentious in both countries. In the past there has been limited urgency in T&T to proceed due to ample gas supplies. However, the emergence of gas supply shortages in recent years, together with the understanding that even the current reduced production plateau will not extend beyond 2025 has provided a clear imperative for T&T to progress these discussions towards an agreement to develop the gas. There is a window of opportunity to process gas through existing consumers as shallow-water gas production declines in the mid-2020's.

While it is understood that the nature of these negotiations will be complex, it is recommended nonetheless that further initiatives are taken, including:

- Setting clear deadlines and timelines within GORTT for progress of the discussions with Venezuela.
- Comprehensive evaluation of the value to T&T of securing an arrangement whereby 100% of produced gas is processed through their existing infrastructure, to allow specific value propositions to be formulated and when appropriate presented to the Venezuelan government.
- Consideration of how agreement to develop the gas reserves could form part of a broader bilateral agreement with Venezuela.

1.7.5 Mobilising Deepwater Gas

The current deepwater exploration programme is a potential source of gas to backfill the shallow-water production profile and extend plateau production from 2025 out towards 2030. The viability of this scenario is entirely dependent on exploration success in the upcoming mid-2016 drilling campaign and on the size and production characteristics of any discoveries made.

Deepwater areas have all been awarded as PSCs and while Poten has access to the model PSC form from previous bid rounds we have not been provided with the agreed terms of profit production split for awarded deepwater blocks. However, economic analysis suggests that provided the actual PSC terms agreed with contractors are at least as attractive as recent shallow-water PSCs and provided commensurately attractive gas prices can be delivered then it would be reasonable to expect that a large (>3 Tcf recoverable) and relatively condensate rich (25 bbl/MMcf) discovery would be attractive to develop.

The key challenge for T&T is to incentivise enough exploration activity in deepwater blocks in an early enough timeframe to ensure that any gas present is developed in time to backfill the shallow-water production profile.

Currently only 1/3 of deepwater blocks have been licensed and 8 exploration wells committed in the first term work programmes. These wells will be drilled in a campaign commencing mid-2016. However, with a nominal probability of success of <20% it would be reasonable to expect only one discovery from the committed programme which may not be gas bearing given that contractors are incentivised to pursue oil prospects over gas due to the superior economics of smaller discoveries. Success in the first work period would encourage operators to pursue subsequent phases but current contracts would deliver a maximum of only 22 wells over the full exploration program.

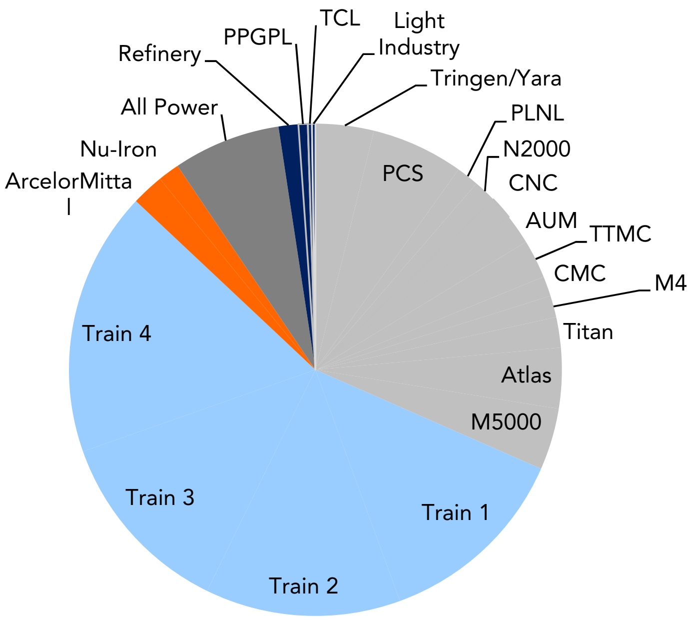
The focus for T&T at this stage should be to expand the number of blocks under license with firm drilling commitments. This will be challenging in the current environment of reduced expenditure across international oil and gas companies, however opportunities for stimulating increased activity should be explored including:

- State-sponsored seismic acquisition.
- Review of fiscal terms and alignment between GORTT and operator incentives.
- Road shows to advertise new fiscal terms and seismic data.

1.8 THE DOWNSTREAM PORTFOLIO

The existing portfolio mix is made up of ammonia, urea and methanol industries, LNG, iron and steel, power and other industries (including supply to TCL and the refinery as well as the consumption in the PPGPL plant) as shown in the figure below. The midstream and downstream gas industry in T&T needs upstream deliverability of 4.3 Bcf/d in order to run at capacity.

Figure 1-21 The Existing T&T Downstream Portfolio
(Source: NGC/Atlantic LNG)



LNG accounts for 58% of the installed consumption capacity, ammonia industries for 16% and methanol for 15%. Table 1-8 shows the consumption for each of the sectors based upon the maximum gas consumed in the period since the year 2000 (Max Gas) and currently contracted daily quantity (DCQ) for supply from NGC for downstream industries, or in the case of the LNG plant the gas volumes the project directly contracts with the suppliers.

Figure 1-22 shows the evolution of contracted gas demand over the Master Plan period, as well as total demand. "Existing + new" demand includes the new "mid-scale" LNG plant and new methanol plant described previously. Where contracted quantities are less that maximum gas consumption of the plant we have labelled this difference as "spare" capacity. The analysis assumes that NGC supply to power generation and other industries continues at 2014 levels.

Of the maximum existing gas demand figure of 4,268 MMcf/d, spare capacity and contracts that have already expired account for 387 MMcf/d, giving a figure for current downstream contracted gas demand of 3,882 MMcf/d. Many contracts expire in the 2018-2020 period, including ALNG Train 1, all of the remaining ammonia plants with the exception of AUM, and all of the remaining methanol plants with the exception of Atlas. Post-the expiry of these contracts the level of contracted gas demand will drop to 2,471 MMcf/d, or 2,646 MMcf/d if the combined 175 MMcf/d of supply to the new LNG and methanol projects is included. In general, when downstream supply contracts have expired NGC has been extending them for 5 year terms.

Table 1-8 Summary Gas Consumption

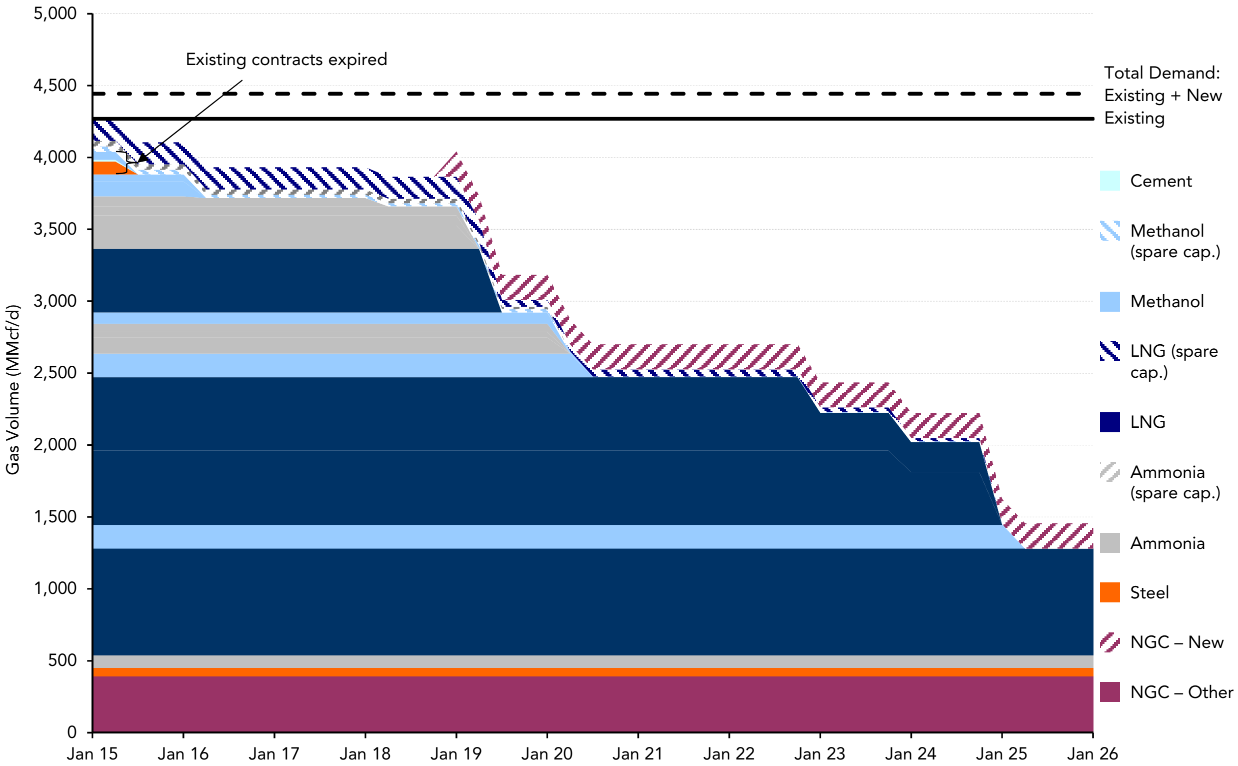
(Source: MEEA/NGC/Atlantic LNG)

Plant	Max Gas MMcf/d	DCQ MMcf/d
Ammonia/Urea	696	658
Methanol	652	558
LNG	2,366	2,1212*
Iron & Steel	151	60.5
Power Generation	301	301#
Other Industries	102	91#
Total	**4,268**	**3,881**

*Includes Train 4 volumes

#Assume same as Max Gas

Figure 1-22 Contracted Gas Demand for Master Plan Period



1.8.1 Downstream Markets & Pricing

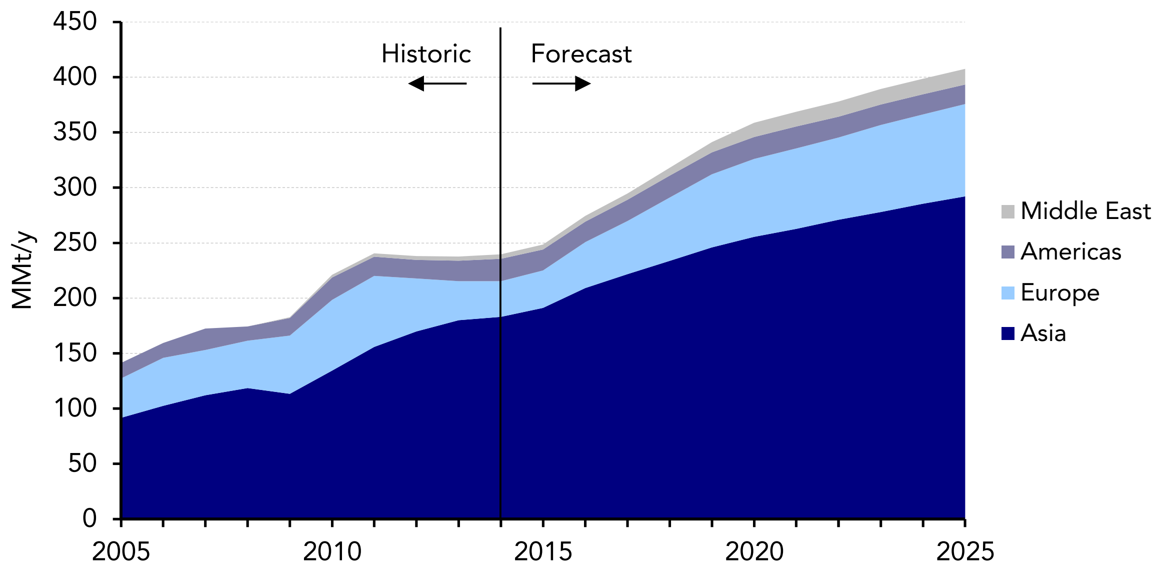
T&T has developed a major gas export industry both directly, in the form of LNG, and indirectly through gas-based petrochemicals (ammonia/urea, methanol). The sale of these products collectively account for ~80% of the gas consumption in T&T. T&T's competitive advantage in addressing these markets has been the low cost of the gas resource and the proximity to the world largest market, the US, which was short on gas supply and had significant demand for LNG and gas-based petrochemicals. These competitive advantages have eroded over time. Incremental gas supply from T&T reserves will be more expensive to develop and the US market is now saturated with gas, bolstered by the rapid growth of shale gas which can be developed at relatively low cost, as a result of which the US is looking to become a major LNG exporter in direct competition with T&T. As T&T gas products are pushed out of the North American market they will have to travel further to reach new markets which will add to logistics costs and reduce competitiveness.

T&T exports are now competing for market share against products from other supplier countries on price. T&T has a competitive edge predominantly to the extent that indigenous resources can be developed and delivered to market at lower cost than those of competitors. Pricing for LNG is not within the control of T&T but the value extracted for the benefit of the country will depend on the efficiency of the value chain and the cost of exploiting the gas. In petrochemical markets feedstock and logistic costs are a key competitive advantage. Understanding the new sources of supply and their cost position is important in determining present and future competition and potential target markets.

1.8.1.1 LNG

LNG demand has grown rapidly and at present is around 240 MMt/y. Demand is expected to continue to grow to around 410 MMt/y by 2025. Growth is anticipated in every major region, except North America (excluding Mexico) where robust growth in domestic shale gas production has almost eliminated imports. The largest markets will continue to be those of Asia which is expected to account for around 70% of demand by 2025. The European market which has been an increasingly important market for T&T LNG is expected to grow in this period, but at a much lower rate than Asia.

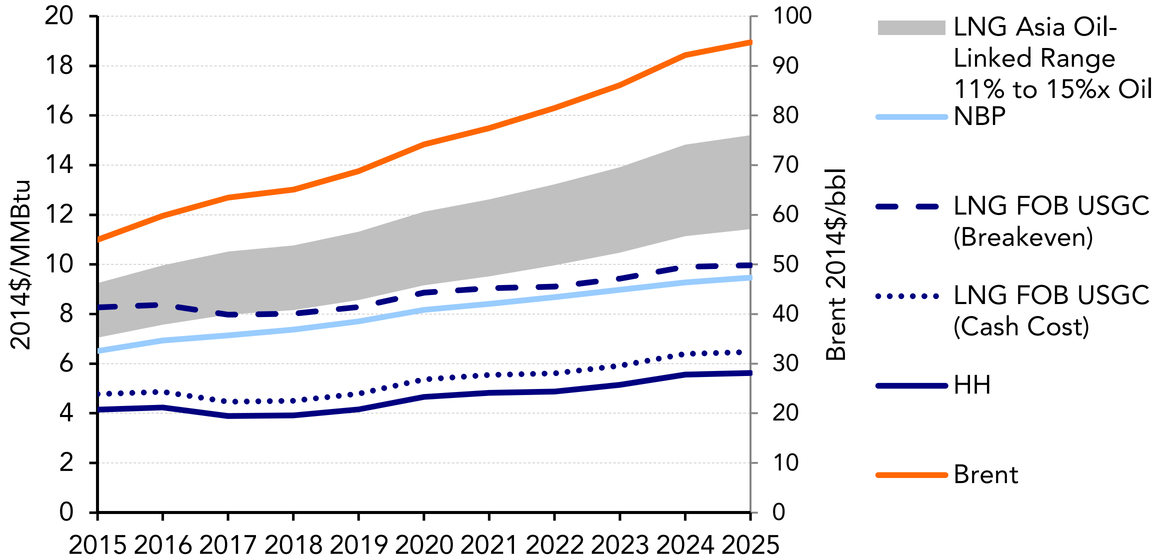
Figure 1-23 Historical & Projected LNG Demand: Global



Longer-term, LNG demand will remain a key constraint to supply growth. Even considering our forecast robust demand growth, it is clear that there will only be sufficient markets to support the development of a fraction of the new liquefaction capacity that could potentially developed in North America and East Africa, for example, over the coming decade. This competitive pressure is expected to continue to apply downward pressure on LNG pricing, impacting new suppliers and existing suppliers negotiating contract renewals, such as T&T. This is being illustrated by declining prices in the market for long-term contracts. Both North America and East Africa will play an important role in setting future long-term LNG pricing as they compete for markets.

Since natural gas developed as a regional business, gas and LNG pricing regimes and formula structures have developed to meet local constraints and the specificities of the regional end-user markets for gas. Accordingly, unlike the oil market, gas does not currently have an international benchmark price. However, similarities lie in the extremely important influence that competing energies, and in particular crude oil and oil products, have on gas prices on all the regional markets. Natural gas does not have a captive market, and is always in competition with other forms of energy: electricity, gas-oil and LPGs in the residential/tertiary sectors, electricity, coal and heavy fuel oil in the industrial sector, and coal, fuel oil and nuclear power in the power sector. Thus its price cannot deviate too much from competing fuels, which always offer a satisfactory replacement.

Figure 1-24 Forecast Natural Gas and LNG Prices



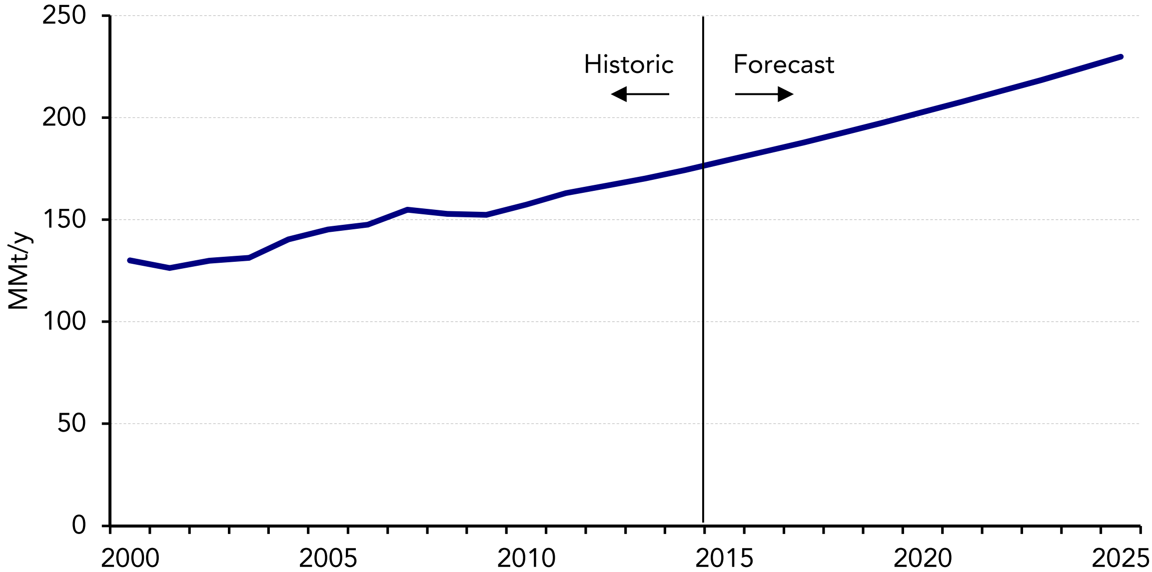
Our forecast of future LNG prices is shown in Figure 1-24. Asian LNG prices are expected to continue to be heavily influenced by oil indexation, partly driven by the high cost of Asia Pacific supply projects, e.g. Australian grassroots projects which required high oil indexation levels and price floor support to support their investment decisions. The large ramp up of North American LNG exports with pricing based on market prices (HH indexation) is bringing a new dynamic to global LNG pricing. It is also leading to the emergence of "hybrid" pricing (with a mixture of HH-based and oil–linked pricing) which may be implemented for new supply projects such as those in Western Canada and East Africa.

The European market is expected to act as a global balancing market, providing a market of last resort for any LNG which is not able to be placed into other markets. Although oil indexation may remain in legacy contracts, LNG delivered to Europe will be at market prices, based mainly on UK NBP price index. European prices will be set by the interaction of supply and demand in the European market, with floor prices expected to be set by the marginal cost of HH-sourced LNG into northwest Europe. We expect downward pressure on the oil indexation slope of Asian long-term contracts due to the combination of (1) supply competition, (2) shift in marginal supplies from Australia to others (e.g., East Africa), and (3) intrusion of HH-linked contracts, increasing competition and forcing slopes down.

1.8.1.2 Ammonia

The global ammonia market is estimated at around 170 MMt in 2013 and is projected to reach around 230 MMt/y by 2025. Growth is expected to be strongest in developing regions, particularly Asia, and Latin America and more muted in North America.

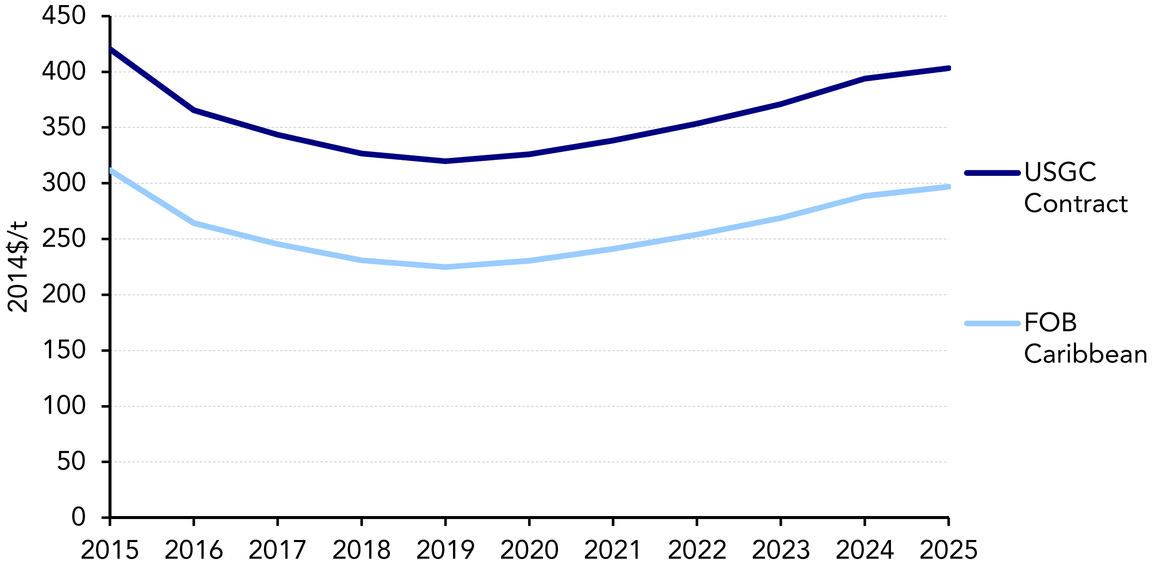
Figure 1-25 Historical & Projected Global Ammonia Demand



The marginal highest cost production is currently ammonia produced from Chinese coal. We expect that global pricing will continue to be supported by the need for production from higher cost regions including Ukraine and Western Europe, with Chinese coal-to-ammonia economics providing a floor price. New production in low cost gas regions including new US production will be price takers.

The FOB Caribbean ammonia price is used by NGC to calculate the feedstock pricing for natural gas. Historically FOB Caribbean prices have been broadly in line with FOB Black Sea marker prices and we expect this to continue. Poten's projections for ammonia prices fob Black Sea are shown in Figure 1-26. They show prices declining to around \$300/tonne by 2017-2020 before a steady increase to around \$400/tonne by 2025 (2014\$).

Figure 1-26 Forecast Ammonia Prices



1.8.2 Methanol

Global demand for methanol (excluding methanol demand in vertically-integrated Chinese Coal to Olefins (CTO)) is estimated at around 67 MMt/y in 2014. Including methanol consumed in CTO, the total methanol market is estimated at 72 MMt/y. China dominates the global methanol market for both supply (~50% installed capacity) and demand (43%). Demand in China is growing at around 12% p.a. while the rest of the world has seen growth rates just over 3% p.a. Methanol to olefins and gasoline blending are leading the growth in the Chinese market. Global methanol demand is expected to reach 117 MMt/y by 2025.

Figure 1-27 Historical & Projected Global Methanol Demand

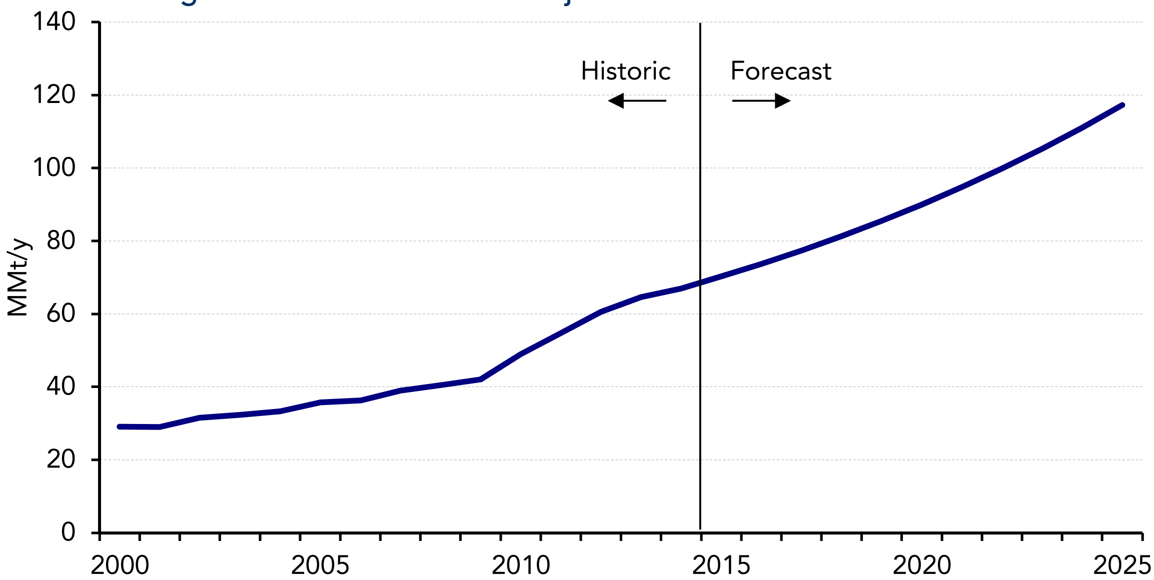
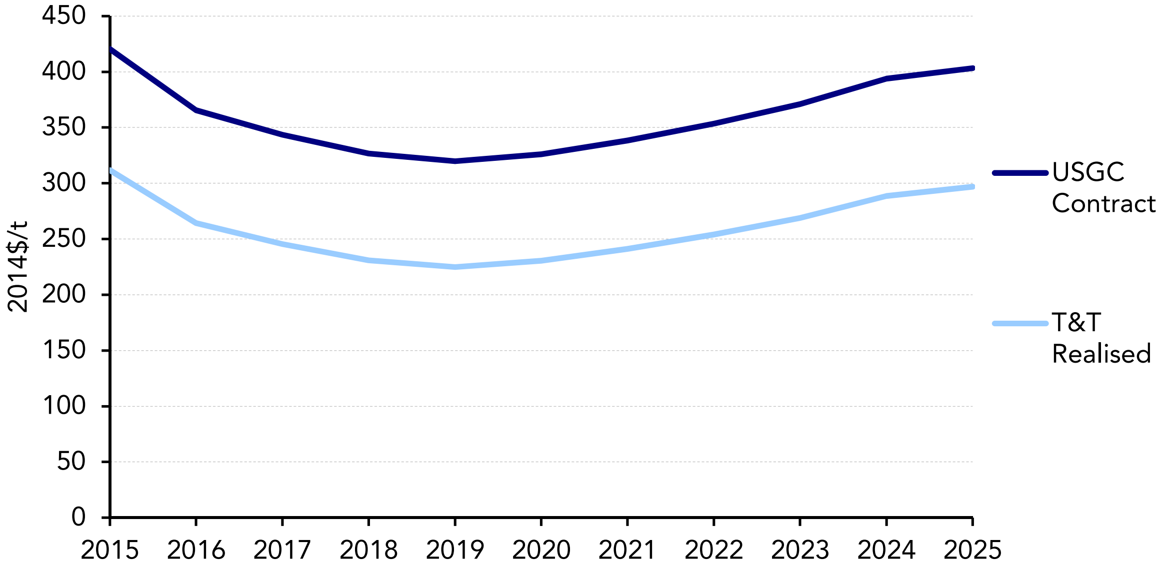


Figure 1-28 FOB USGC Methanol Contract Price Forecast



Methanol prices are expected to decrease from current levels to around $320/tonne by 2019, as lower oil prices feed through to lower methanol prices, before recovering over time to around $400/tonne by 2025 (2014$). Realised netback prices to T&T producers will continue to reflect a market discount of ~15% and freight cost differential from USGC contract prices.

1.9 GAS PRICING IN T&T

Gas pricing in T&T, and indeed the commercial structures generally, reflect the evolution that the market has undergone in the last several decades. In the early years the commercial structures developed reflected the conditions at the time. There was abundant gas but the market for gas was undeveloped and there were significant uncertainties for downstream marketers in terms of offtake and affordability of products. Many downstream investments (e.g. methanol plants) were adding significant incremental capacity to the global market and there was some uncertainty over the evolution of product pricing. Gas pricing at this time was generally on a fixed price basis. The downstream markets evolved and matured over the past 10-15 years, and structural changes in markets have led to a change in the relative risks associated with different parts of the gas value chain. Gas pricing in T&T has evolved with the markets; for example in the 1990s product related netback pricing was introduced for petrochemical gas supply.

1.9.1 Pricing Arrangements / Framework

In T&T the price of gas is set according to end-user. As a result, prices vary according to buyer: LNG, petrochemical production, power generation, heavy industry, or general commercial as shown in the following table:

Table 1-9 Gas Pricing Structures in T&T

End Use	Pricing Mechanism
LNG	Netback pricing
Petrochemical (ammonia and methanol)	Product indexed pricing
Power Generation	Set by GORTT
Heavy industry	Cost plus
Light industry	Cost plus
Commercial	Set by GORTT

The use of netback pricing in LNG and petrochemical gas supply already allows T&T to share in the upside movement of commodity prices. The key issue is not the pricing mechanism so much as whether the products are being sold in the highest value markets and whether the price mechanisms capture the appropriate resource rent.

Domestic gas pricing is an important consideration for the gas industry, with prices set low for several consumers/groups/industries. In most countries where there are competitive markets the supply of gas to the power sector usually provides the highest value option for the producer, as gas will be competing with alternate forms of power generation. In T&T GORTT has elected to provide power at a highly subsidised price as a means of distributing the wealth generated from the energy sector to the wider population. RIC sets the price at which the power utility (T&TEC) sells power to different classes of consumer. In order to sustain T&TEC financially NGC sells it gas at a current price of around $1.35/MMBtu, with inflation escalation. This has caused major distortions in the gas value chain as the price is below the economic cost of production of many of the upstream suppliers. This situation is managed by NGC. NGC is able to offer gas to T&TEC at the regulated price because it can pool gas supply and charge a higher price to other industries, notably the petrochemical industry. There are several issues with the way in which power is priced in T&T:

- The low price of power does not encourage energy efficiency and observation indicates that a large amount of the power generated is not used effectively. A power price in line with that charged elsewhere in the Caribbean would encourage more efficient energy use and bring greater revenues to T&TEC. In the short term it would reduce the amount of power required and the amount of feed gas.
- The low gas price also diminishes the incentive and the ability of T&TEC to invest in more efficient generation capacity (e.g. CCGT plants which have a thermal efficiency of ~50% compared to the efficiency of the open cycle plants of less than 30%.) If T&TEC moved entirely to CCGT generation as is the plan at the present time there would be a significant reduction in gas consumption. This is in addition to any saving through more effective pricing identified above.

It is widely documented that such subsidies are relatively ineffective in benefitting the intended target of the poor/less well off in society. In fact the benefits accrue largely to the better off sections of society who have larger homes, more appliances etc. It would be more effective for GORTT to more directly target the poor by making direct payments through welfare support or, as a second best option, limiting the amount of electricity that qualifies for the low electricity price. Users consuming more than the qualifying amount would pay a higher price on the excess, which should be set at a level to cover the cost of the subsidy.

1.10 DOWNSTREAM COMMERCIAL ARRANGEMENTS & VALUE GENERATION

An analysis was undertaken to determine the value that GORTT is receiving from its existing gas sales to LNG, petrochemical industries, steel plants and domestic sector.

1.10.1 Netback Prices

The figures below compares the effective netback price to the plant inlet across the various downstream industries from 2005 to 2014.

Figure 1-29 Netback Price Comparison at Plant Inlet by Plant

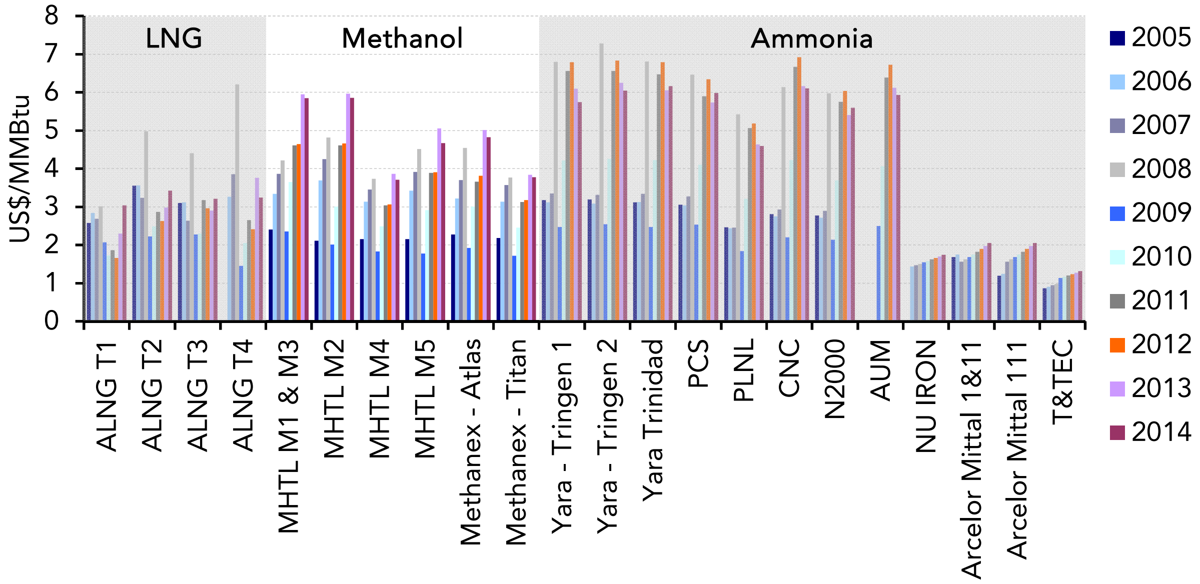
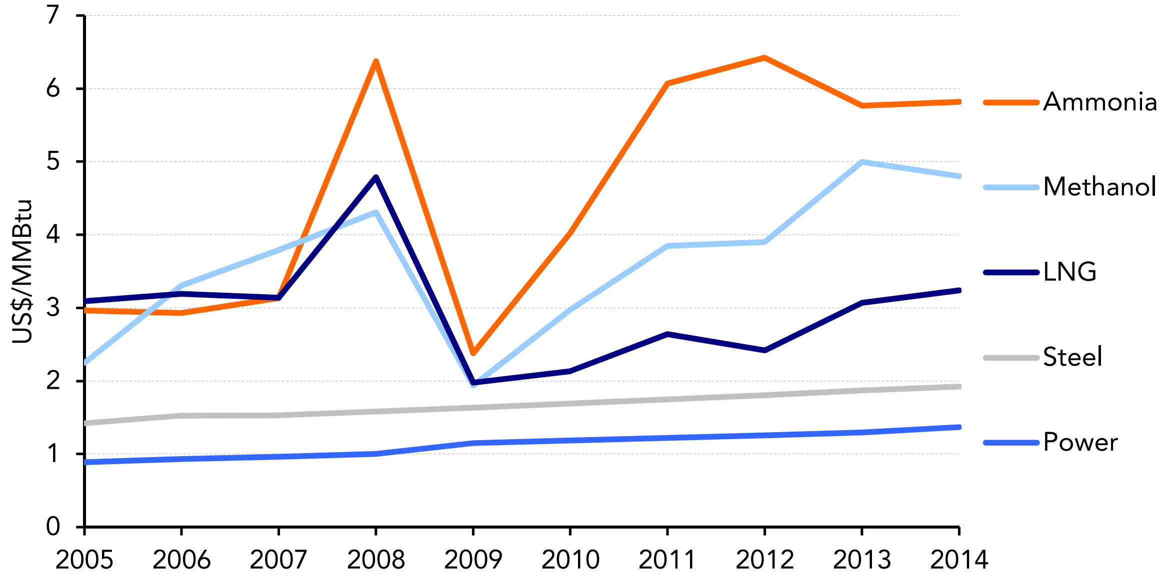


Figure 1-30 Netback Price Comparison at Plant Inlet by Sector



Over the period from 2005 to 2014 the ammonia plants consistently gave the highest netback prices to T&T, followed by the methanol plants. Typically one would expect that LNG would have been the most attractive form of gas utilisation for gas export. Over this period LNG was selling at high prices (particularly in the Pacific Basin, where LNG prices were often in excess of $15 MMBtu). Any plants constructed before the significant global construction cost rise over the latter part of the last decade will have benefitted from low liquefaction costs and will likely have netted back prices to the plant inlet well in excess of $7/MMBtu.

Unfortunately for T&T, as detailed earlier in this section, the commercial and contractual structures of ALNG trains have been such that little of the benefit from high global LNG prices has flowed back to T&T. This is illustrated by the low netback prices that have been realised over recent years (weighted average of $2.42/MMBtu in 2012, $3.07/MMBtu in 2013 and $3.22/MMBtu in 2014). As well as ammonia, methanol has also outperformed LNG over recent years, with weighted average netback prices of $3.90/MMBtu in 2012, $5.00/MMBtu in 2013 and $4.80/MMBtu in 2014.

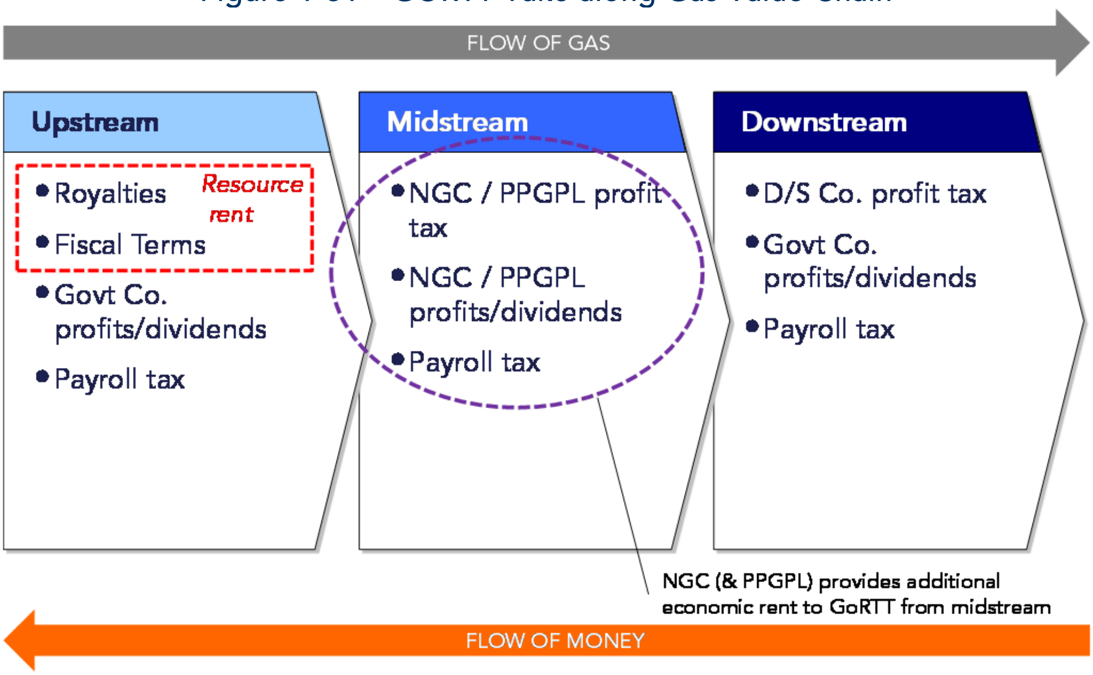
It is pertinent to note that even in 2008, a time of high HH prices and a high watermark for netback prices for ALNG, the weighted average netback price from LNG was $4.79/MMBtu, which was better than methanol ($4.31/MMBtu) but significantly worse than ammonia ($6.37/MMBtu).

With the exception of T&TEC, the steel plants are consistently the poorest performers, buying gas from NGC at weighted average prices that have increased from $1.69/MMBtu in 2010 to $1.92/MMBtu in 2014.

1.10.2 GORTT Take

Although realised netback prices are a useful indicator of value flowing back to T&T from its gas-based industries, the key determinant of the "value" provided by the industry is the overall GORTT take from each of the gas value chains.

Figure 1-31 GORTT Take along Gas Value Chain



GORTT receives revenue from all three stages of gas value chain, as illustrated in Figure 1-31. Estimated overall GORTT take is shown in the figure below from 2008 to 2014. Insufficient data was provided to extend this analysis back to 2005 or to assess GORTT take from the iron & steel sector.

Figure 1-32 Overall GORTT Take Comparison by Plant

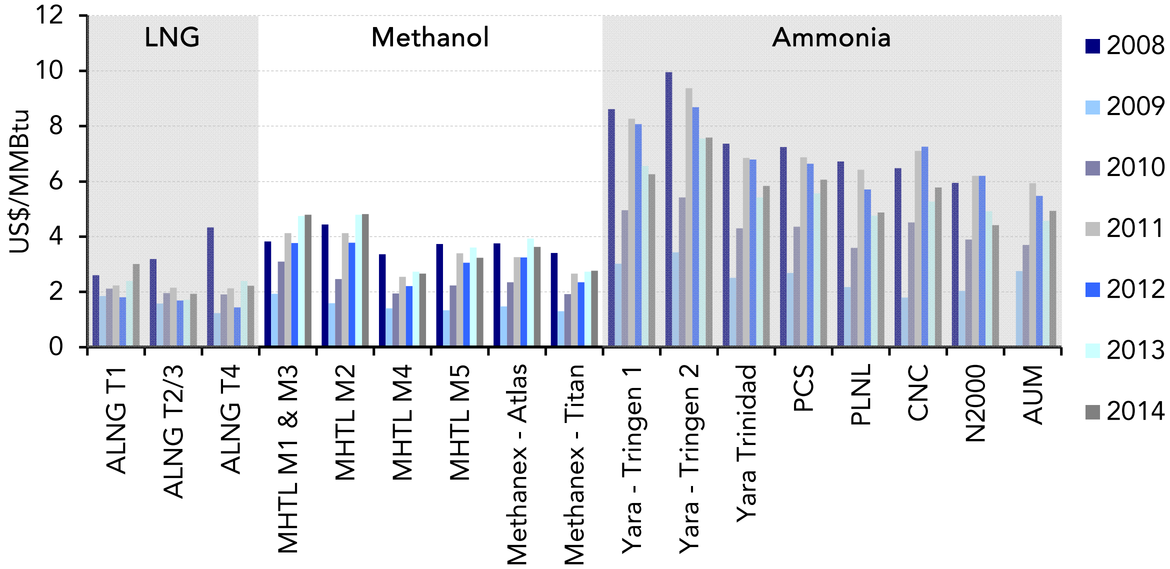
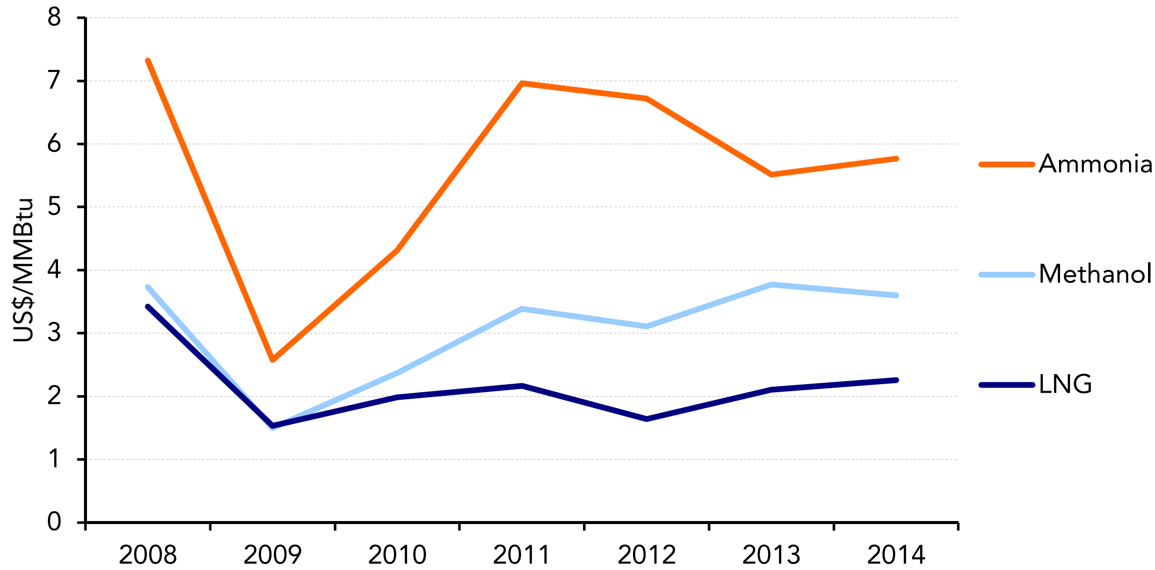


Figure 1-33 Overall GORTT Take Comparison by Sector



As would be anticipated, the results largely mirror those of the netback gas price analysis. The returns from LNG have been relatively poor compared to those from ammonia and, to a lesser extent, methanol plants. This is due to the particular commercial and contractual structures that govern ALNG, rather than a factor of the industry itself. Our analysis suggests that under different circumstances GORTT take from LNG could have been as high as those from ammonia over the last 5 years, at a time of historically high global LNG prices.

The analysis is further illustrated by the GORTT take breakdown provided by plant (Figure 1-34) and sector (Figure 1-35)

Figure 1-34 GORTT Take Breakdown for 2014 by Plant

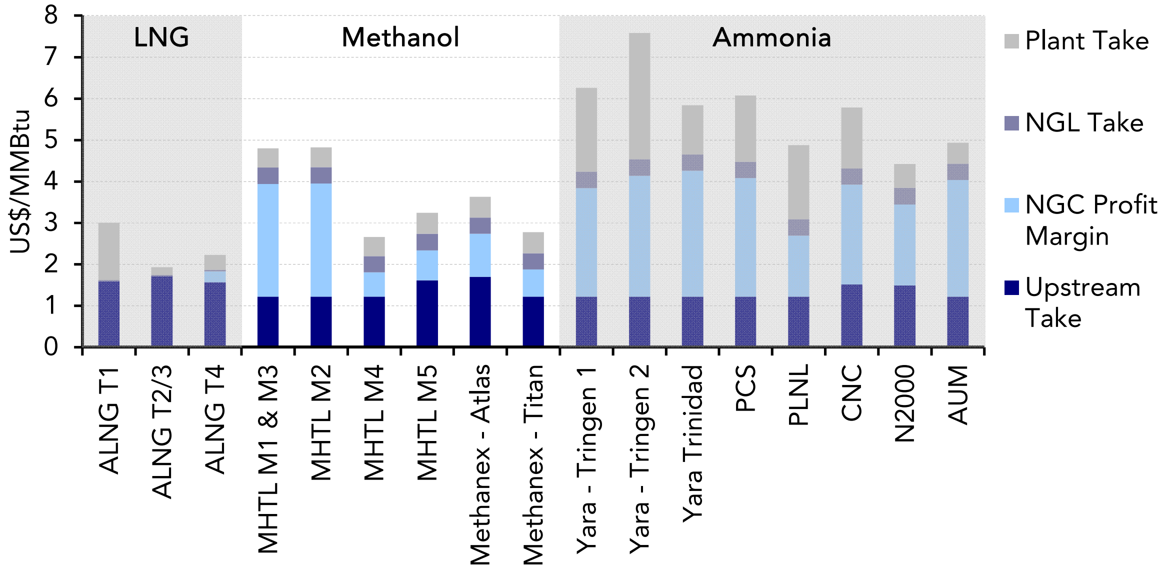
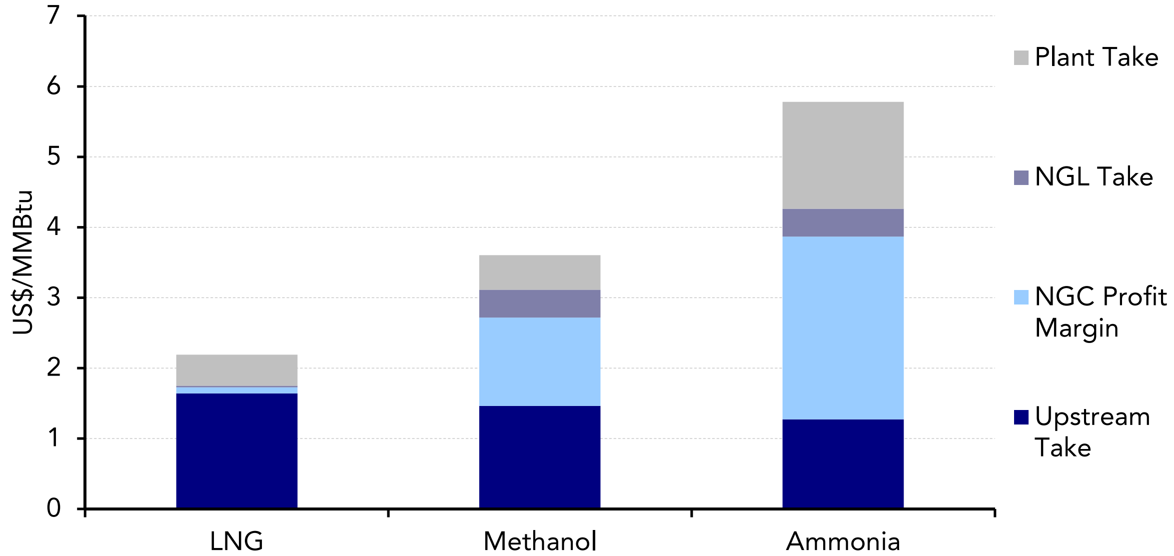


Figure 1-35 GORTT Take Breakdown for 2014 by Sector



Key points to note from the analysis are as follows:

- The importance of NGC's estimated profit margin to the overall GORTT take from the methanol and ammonia value chains is clear.
- GORTT has substantially benefitted from its stakes in the Tringen 1 & 2 ammonia plants..

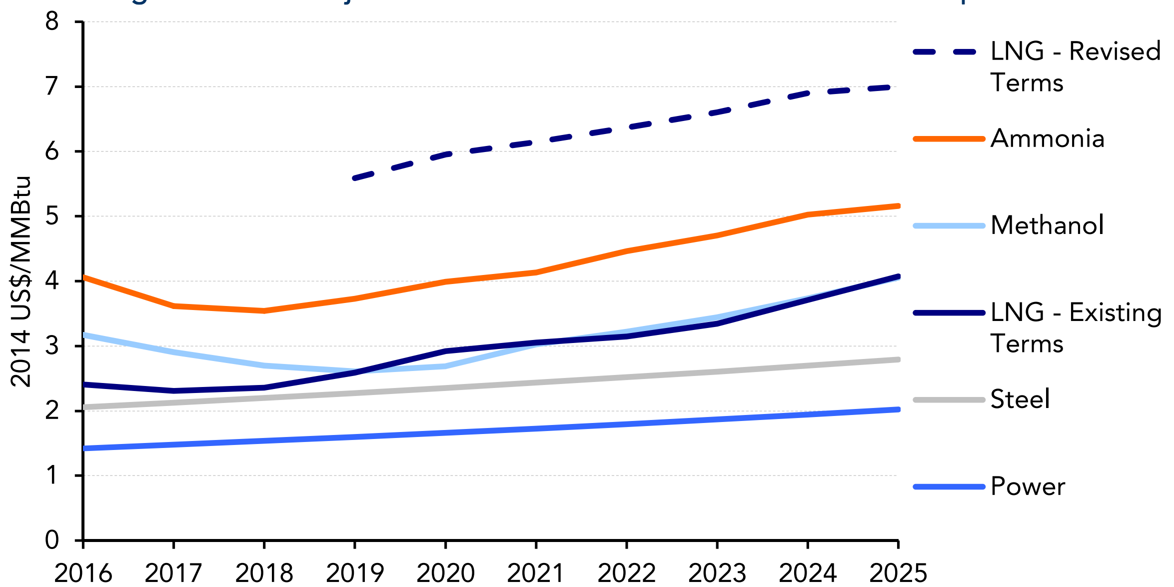
- NGC's profit margin varied significantly between different plants in the same sector in 2014. The data provided suggests that NGC has been able to capture higher prices from downstream industries when existing supply contracts have expired.
- GORTT take was significantly higher from ALNG Train 1 than Trains 2/3 or Train 4 in 2014, due to a far higher plant take.
- Other than from the upstream, GORTT take from the ALNG Train 2/3 and Train 4 value chains was very modest.

This analysis has implications for both future marketing arrangements and any shortfall management. Under prevailing market conditions and the existing marketing structures the ammonia industry has been creating better value for T&T and in the event of gas shortfalls and potential curtailment, gas value would be maximised by preferentially directing supply to the ammonia industry, followed by supply to methanol plants. The key issue going forward is the extent to which the relative value proposition offered by the main gas-consuming sectors is likely to change in future.

1.10.3 Netback Price Projections

Based on the future price projections and the historical netback price analysis described earlier, an estimate has been of the future netback prices that are projected to be realised from the various downstream sectors, as shown in the figure below.

Figure 1-36 Projected Gas Netback Price as Plant Inlet Comparison



Under the existing arrangements, ammonia is projected to continue to provide the most attractive netback prices. Netback prices from existing LNG arrangements are projected to remain relatively low, with methanol trending down to similar levels to those from the existing LNG arrangements by 2019. The potential LNG pricing that could be achieved assuming sales into the NW European market could be much higher. It is clear from the analysis that a significantly opportunity exists for T&T to increase the netback gas prices that are received from LNG after the existing agreements expire. Our projections of potential revised LNG arrangements would make LNG clearly the most attractive of T&T's existing infrastructure for gas monetisation.

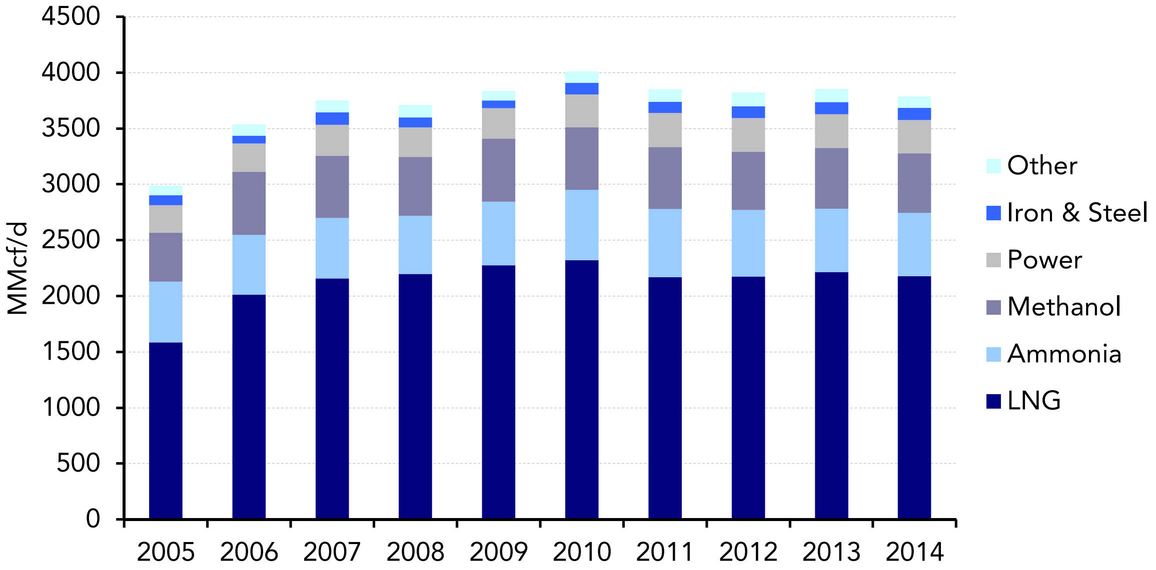
1.11 GAS SUPPLY AND DEMAND SITUATION

1.11.1 Gas Supply into Consumption

The overall gas supply to downstream industries has declined somewhat since peaking in 2010. This has been due to lower supply from upstream producers due to reduced deliverability and protracted maintenance periods. As a result all export-based industries have seen gas supply availability declines.

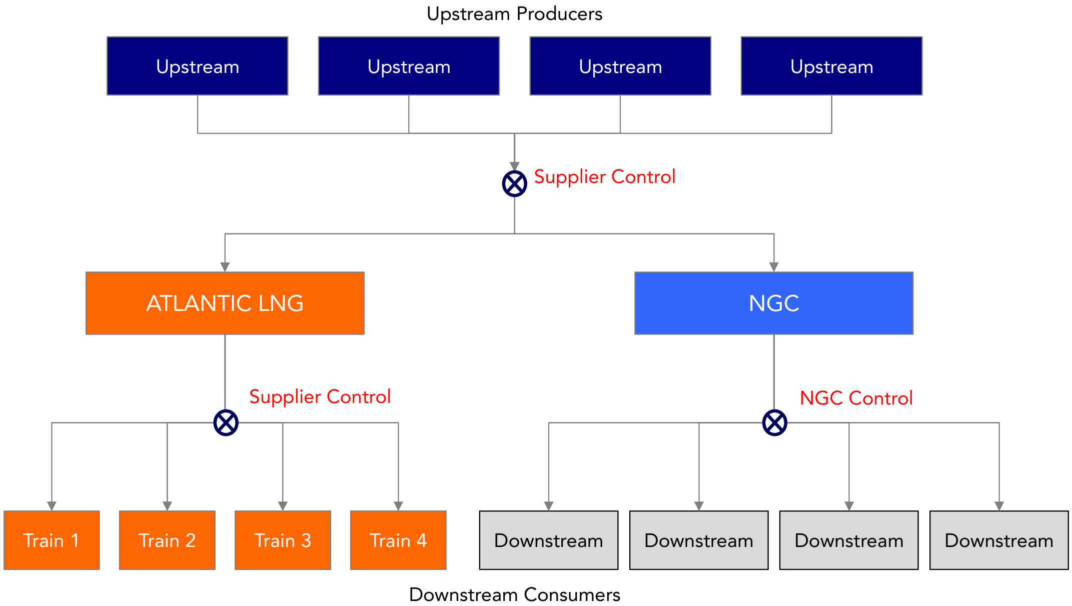
Figure 1-37 Historical Gas Supply to Downstream Consumption Sectors

(source: MEEA)



As shown in the figure below, gas supply is managed at 3 virtual points in the system.

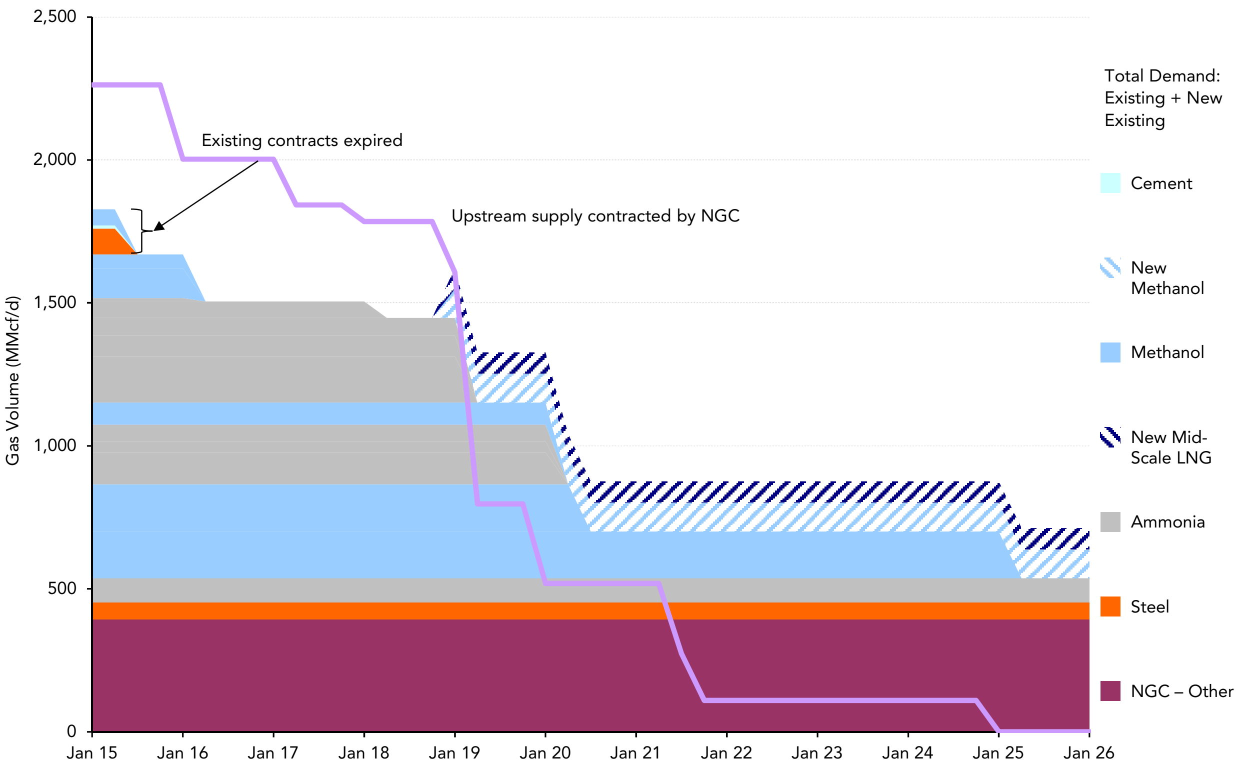
Figure 1-38 Management of Gas Supply to Downstream



As shown in the figure below, NGC appears to be in a comfortable position in terms of contracted gas supply, although there are some downstream contracts from 2019 onwards for which it does not presently have contracted upstream gas supply. However, as discussed previously, actual supply to NGC from upstream has been well below contracted supply which is currently ~2.1 Bcf/d, versus 2014 supply of ~1.6 Bcf/d.

Figure 1-39 NGC Contracted Gas Demand vs. Projected Supply

(source: MEEA, NGC)



As NGC has been unable to enforce supply obligation in its upstream contracts it is largely in the control of the upstream suppliers to allocate gas supply between their contracts to supply ALNG and their contracts to supply NGC. As discussed previously a key issue is that although all major downstream industries have experienced declining gas supply availability, overall gas supply to LNG has been largely maintained at contractual levels while overall gas supply to NGC has not. This in turn has left NGC short of gas to supply its downstream customers.

In addition to the long-term supply deficit, the short-term variability of supply to NGC from upstream has left NGC in the difficult position of managing this variability with its downstream customers. Contractually NGC has handled this under delivery/mismatch situation by declaring force majeure (FM) or partial FM on the downstream buyers, thus relieving it of performance obligations. Downstream companies report that FM has been declared as often as 3 times in a week on certain occasions.

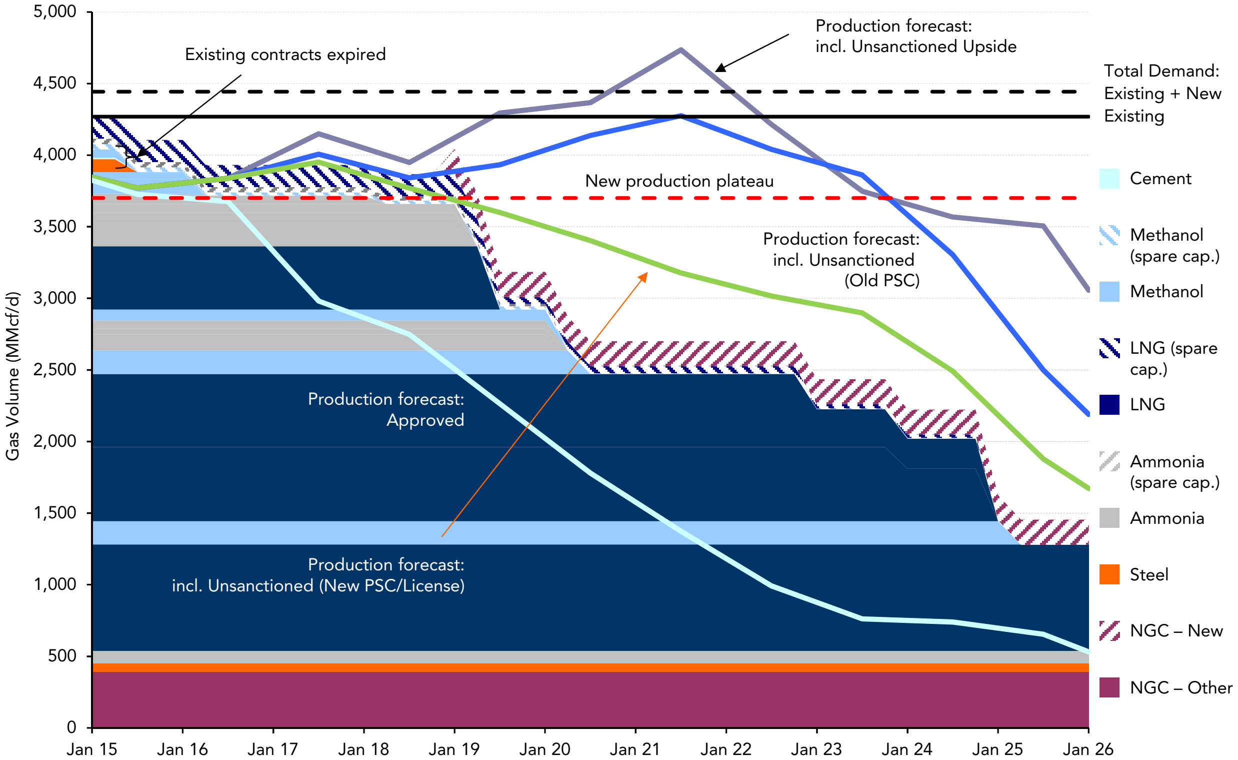
NGC's reliance on FM to handle downstream curtailment is not a typical use of FM and it would be preferable if there were alternative, more transparent mechanisms to deal with shortfall situations. In Poten's view NGC should consider including in its downstream GSAs provisions to enable NGC to make a downward adjustment in Annual Contract Quantity in the event of scheduled upstream maintenance impacting its upstream supply volumes.

NGC has acted to ameliorate future interruptions by aligning planned shutdowns in upstream and downstream operations so that reduced supply is offset, as best as possible, by a reduced demand. This is a more positive approach rather than claiming FM, which has the potential to further polarise the sector, given the history of inappropriate use of this mechanism in both upstream and downstream supply. Closer coordination between all participants is also needed to reduce the impact of planned upstream supply shut-ins as well as agreed procedures for curtailments when temporary shortages occur. Dialogue with industry is required to determine the best methods for addressing both features.

1.11.2 Future Supply and Demand Balance

Based on the potential future gas supply profiles and the downstream gas supply contractual commitments and demand, T&T's projected future gas supply and demand balance is shown in the figure below. It should be noted that an assumed shrinkage of 3.5% has been applied to the gross figures to give an expected sales gas figure. This shrinkage has been observed in MEEA data for 2014.

Figure 1-40 Contracted Gas Demand vs. Projected Supply Scenarios



T&T has a current downstream portfolio that could consume an estimated ~4.3 Bcf/d. This demand is not being fully met and in Poten's view it is not realistic to expect that it will be met in the future on a long-term basis (under the most optimistic supply forecast demand could be fully met for a period of ~3 years from 2019).

Considering only approved upstream gas supply projects, gas supply will fall rapidly from 2016-17 and supply will be some way short of meeting existing downstream contractual commitments, i.e. the current shortfall situation will deteriorate further. Adding in production from unsanctioned developments under new PSC/license terms would provide sufficient gas to meet downstream contractual commitments, but not to meet demand. It would also only provide limited volumes/durations for expiring downstream contracts to be extended from 2019. Extending expiring downstream contracts well into the 2020s will require substantial unsanctioned production under the more economically-challenged old PSC terms.

Poten's view is that gas supply rates of ~1.4 Tcf/y are likely to persist in the coming years and are a realistic expectation of future supply. This equates to a sales gas figure of ~3.7 Bcf/d that is shown as the "new production plateau". At this level supply will be insufficient to meet downstream contractual commitments until contracted volumes drop to ~3.7 Bcf/d from 2016, and there will be no excess supply over contracted downstream sales until contracted volumes drop to ~2.9 Bcf/d from 2019 with the expiry of the contracts to supply ALNG Train 1 and almost all of T&T's ammonia capacity. Under such a scenario for the next several years at least there is not going to be any surplus gas available to justify the extension by NGC of any of its downstream contracts that have already expired or those that expire before 2018. Further extension of any downstream contracts by NGC will only extend the existing contractual shortfall situation.

It is also clear that the sanctioning of any gas supply to new downstream ventures will come at the expense of supply to existing operating assets, i.e. if a new plant is developed then it is likely that an old plant will have to be shut down. The 175 MMcf/d that is planned to be supplied to the new mid-scale LNG and methanol plants is shown as "NGC – New".

While gas supply is likely to available from 2019 to extend supply contracts to existing downstream industries, it is highly likely that gas supply will be insufficient to fully meet demand and as such decisions will have to be taken over which contracts to extend and which downstream industries to shut down. In the absence of large volumes of incremental supply, directionally the gas sector will need to focus on arrangements to achieve higher gas prices and greater efficiency in the existing plant and production facilities, i.e. a focus on developing value rather than growth.

1.12 FUTURE MID & DOWNSTREAM SECTOR

It is clear that decisions will have to be taken to manage what is likely to be an increasingly gas-short situation. It is also clear that the commercial arrangements of various aspects of the mid and downstream sector have not effectively maximised the potential return to GORTT from the gas sector over recent years, particularly from LNG. Under these circumstances it is appropriate to consider whether the existing structures of the mid and downstream areas of the gas sector are optimal from a GORTT perspective and to identify potential areas for improvement.

1.12.1 Prioritisation / Allocation of Gas

In an ideal world the development and management of a portfolio for T&T natural gas resource utilisation would be based upon a number of parameters:

- GORTT take per unit of gas produced.
- Employment generated.
- Development of the local skill base.
- Reduction of exposure to volatility of specific markets.

Certain industries would contribute to the various parameters at different levels; some industries may add more value but employ fewer people, while other options may result in a lot of jobs and broaden the local skills base but provide lower value for the natural resource. The purpose of developing a portfolio is to get a balance across the range of parameters, and ensure that there is not undue exposure to one particular market.

Poten has undertaken an assessment of the historical GORTT take from the various gas value chains (see Section 1.10). We have insufficient data available to undertake an assessment of future GORTT take from the various value chains. However, the netback price projections described in Section 1.10 can be taken as a reasonable proxy for the expected relative attractiveness of the different downstream sectors for GORTT over the coming years.

1.12.1.1 Contractual Shortfalls

Management of Shortfalls

Since 2007 and more significantly since 2010 there have been shortfalls in contracted gas supply to the downstream industries, due to combination of factors; insufficient gas deliverability on the part of upstream suppliers, the contractual inability on the part of NGC to impose firm volume commitments upon suppliers and, periodically, operational upsets which impact a supply which cannot be compensated for by the remaining producing fields. To date the shortfall situation has been managed through three distinct processes:

- The management of gas supply between ALNG and NGC, which is in effect bpTT and to a lesser extent BG determining the split of its gas supply between ALNG and NGC. BG physical supply from NCMA is linked directly to ALNG but supply from ECMA is not.
- ALNG shareholders allocating gas across ALNG trains.
- NGC managing the supply to its downstream industries (generally) imposing cuts on a pro rata basis across the industries while maintaining supply to the power and domestic sectors.

The underlying premise in the existing process, at least in regard to NGC's position, has been that gas supply shortfalls are short-term phenomena and that following a shortfall there will be a reversion to full supply. Indeed expiring downstream contracts have been renewed by NGC at their existing ACQ levels. However, in recent years it has become clear that the shortfalls are not temporary aberrations, but a more fundamental lack of gas deliverability, and the analysis undertaken shows that this situation will continue at least until 2016 when a number of NGC downstream contracts will expire.

Poten's analysis of upstream operator plans shows that a plateau of around 3.7 Bcf/d of supply to downstream is feasible assuming that investment decisions are made on a timely basis. If future gas supply is lower than the forecast new production plateau then the contractual shortfall situation could be exacerbated and accelerated.

The existing contractual shortfall situation through to at least 2016 and its potential future extension is such that there will be a need for active management of supply into consumption. Given the knowledge that there is insufficient supply to meet the volume requirements of remaining contracted supply it would not appear prudent for NGC to extend any of its contracts that expire before 2019.

Options for Dealing with Shortfalls

In considering the various options to manage the contractual shortfall in supply it is noted that GORTT has conflicting objectives:

- Maximisation of the value received for the gas – in a gas-constrained environment GORTT would like to see the gas directed towards the plants that offer the highest value for the resource.
- The maintenance of contract sanctity and the reputation of T&T as country which respects commercial relationships.

Furthermore, GORTT appears to have limited ability to control the allocation of gas, and has no direct control over the volume of gas sent to ALNG rather than to NGC. Any action to manage supply outside of the gas supplied through NGC is out of the direct reach of GORTT.

There are three possible approaches GORTT could take, and these are set out in the table overleaf.

Table 1-10 Options for Dealing with Supply Shortfalls under Existing Contracts

Option	Mechanism	Pros	Cons
Non-Discriminatory (Current approach)	• Pro rata cuts to all buyers from NGC • Allocation takes place on an annual basis • Volume into LNG not determined by GORTT/NGC	• Respects contracts to the extent possible • Equitable for NGC customers • Transparent	• Does not ensure highest value for T&T • Ultimately may shut down high value plants if supply insufficient to meet operational requirements
Discriminatory: Centrally Planned	• GORTT would allocate gas according to value provided to T&T, including LNG & within NGC portfolio • MEEA would maintain value model and allocate volumes preferentially to higher value buyers • ALNG/NGC split may be established in PSC TCM meetings • Allocation takes place on an annual basis and "within" the framework of the existing contracts	• Maximises value to GORTT – economically efficient allocation	• Disproportionate cuts to low value buyers • Parties may not be willing to accept and may contest , although pricing to upstream could be maintained
Discriminatory: Market Based	• All contracts are cancelled and buyers tender for supply – competing on price for gas	• Maximises value to GORTT & upstream • Most efficient economic allocation – gas goes to the highest bidder at any given time • Encourages energy efficiency	• Highly complex to enact in practice • Requires abandonment of existing contracts • Disproportionate cuts to low value buyers • Parties would likely be unwilling to accept and would likely contest – potentially extensive litigation • Would create major upheaval in sector

1.12.1.2 Future Downstream Contracts

A more selective approach to downstream contract renewals will inevitably be required in future, rather than the apparent approach of NGC to date which has been to extend expiring contracts for 5 years in the hope the supply and demand situation will improve. Any approach taken will also have to include LNG in its analysis of which contracts to extend, which has not been an issue to date.

As under the contractual shortfall situation, GORTT should be seeking to maximise the value received from the gas produced, which in an environment where demand cannot fully be met means directing gas towards the plants that offer the highest value for the resource. This is not happening under the present system of all contracts being extended without apparent analysis of their relative value to GORTT.

Options for GORTT

In Poten's view there are again three possible approaches GORTT could take towards renewing downstream gas supply contracts and these are set out in the table below. Each of the options seeks to maximise value from GORTT's perspective.

Table 1-11 Options for Contracting Future Gas Supply

Option	Mechanism	Pros	Cons
Centrally-Planned Approach: Allocative	• GORTT directs incremental supply to expected highest value, determining which buyers receive new gas based upon expected value of terms offered, including LNG • Implication is that NGC is sole buyer of new gas and sole seller of new supply	• GORTT seeks to maximize the value obtained from its gas resources • NGC could offer a basket price to suppliers or direct high cost supply to high value demand (matchmaking), ensuring an adequate price to marginal supply • Should be a relatively workable option	• Requires significant GORTT intervention in the sector • Allocating supply will not be a transparent process • Will rely on projections of expected future value to GORTT – highly dependent on future commodity price projections
Centrally-Planned Approach: Tendered	• New supply tendered out to all prospective buyers who compete on price • Implication is that NGC is sole buyer of new gas and sole seller of new supply	• As above • Transparent and fair price discovery process	• Complexity in establishing tender parameters between different commodity offtakers • Could only generate competition between plants with contracts expiring at the same time
Market-Based Approach	• Buyers/sellers free to transact with each other • NGC reduced to providing transportation services only • Domestic market obligation required to ensure supply to the local market (power etc.) • Needs oversight to ensure arm's length pricing and avoid transfer of value downstream / offshore	• Economic theory suggests this should give an efficient allocation	• In shortfall situation low-cost suppliers pick off high-value buyers leaving higher-cost supply with lower-value buyers • Unbundling would require significant time/effort and development of new regulatory capacity • Rent presently captured by NGC would be moved upstream, to be shared with upstream contractors

1.12.2 Sectoral Structural Issues & the Role of NGC

1.12.2.1 Current Role of NGC

NGC is the only player in the midstream sector and covers a multitude of roles, not just in the midstream but across the whole hydrocarbon sector. Inter alia the company undertakes the following activities:

- Sole wholesaler of gas to the downstream and industrial sector, and in this role acts as the aggregator buying gas from the upstream suppliers and selling to the downstream buyers.
- Owner and operator of the midstream transmission infrastructure and acts as the monopoly transporter of gas to the downstream sector. This service is not explicitly offered for the most part as it provides a bundled tariff of gas and transportation to the downstream buyers.
- The company has, through wholly-owned subsidiaries, shareholdings in a number of E&P assets in T&T.
- The company, via subsidiaries, is a shareholder in Trains 1 and 4 of ALNG and also an offtaker from Train 4.
- Via subsidiaries, NGC now holds ~82% equity interest in PPGPL, the country's sole cryogenic gas processing facility
- The company acts as the business development arm of the local gas industry through NEC, a wholly-owned company, charged with bringing in new investors to the sector. In this role it is involved in the granting of investment incentives for new developments.

There are a number of issues related to the existing roles of NGC in the sector:

- At present MEEA and MOFE oversee NGC activities, but there appear to be no formal criteria applied in regard to its merchant role as single buyer and the sole provider of transportation services in the country, or in terms of its service obligations or pricing despite its monopoly position in the market.
- Conflicts of interest. NGC is playing multiple roles in the gas sector supplier and the potential for conflicts is high.
- Transparency. The fact that NGC offers only bundled services means there is a general lack of transparency in the sector.
- Aggregation. The changing supply and demand balance from surplus to deficit has been very challenging for NGC over the past few years in its role as aggregator.
- Concentration of expertise. As NGC undertakes numerous roles in the T&T gas sector the overall GORTT know-how of the sector is highly concentrated in this organisation.

1.12.2.2 Options for Future Sector Structure / Role of NGC

The various options for the future structure of the sector and the role of NGC detailed are summarised in the table overleaf.

Table 1-12 Options for Gas Sector Development – Role of NGC

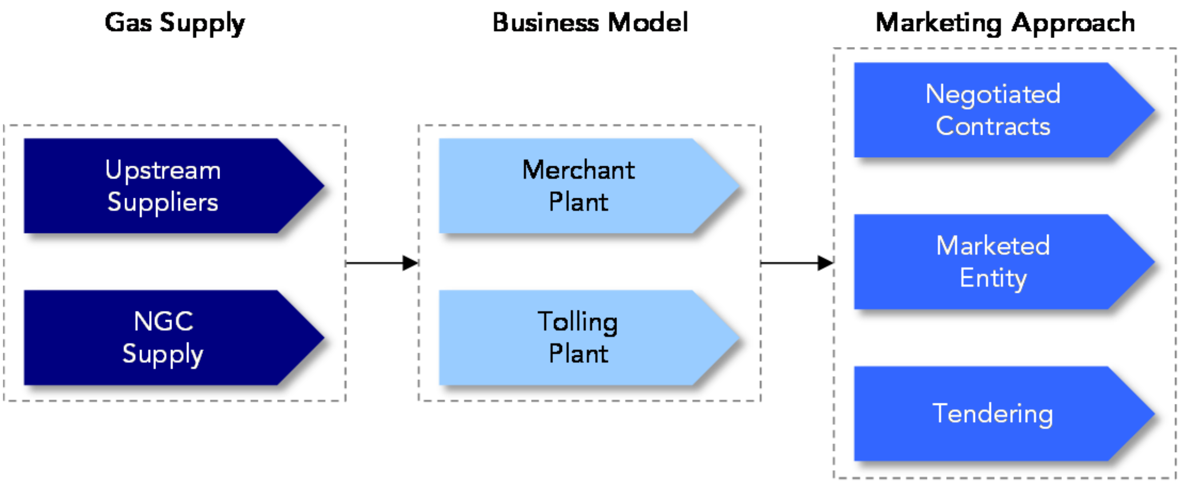
Option	Rationale	Implementation Requirements	Comments / Issues
No Change	• The existing situation is better than all the alternatives	• Business as usual	• NGC will increasingly be caught up in conflicts of interest as gas allocation decisions occur more frequently • NGC margin will be subject to erosion • Volume mismatch risk remains with NGC
NGC becomes single buyer for all gas in T&T	• Efficient route for GORTT to extract value from LNG • Allows NGC to manage supply allocation to the whole sector • Would allow NGC to offer blended prices to suppliers	• As LNG contracts expire NGC incorporates supply to LNG into its wholesale portfolio	• NGC extends monopsonist powers to whole sector • Sector will lack transparency • Potentially increases NGC volume risk • Appetite of some upstream suppliers to accept basket pricing uncertain • Incumbents will likely oppose as existing LNG arrangements have generated substantial value for them
NGC business refocused on wholesaling and transmission	• Removes potential upstream conflicts of interest • Focuses NGC business on core skills	• Divestment of non-core assets (e.g. upstream assets)	• No obvious reason as to why NGC is the best owner of upstream assets • GORTT would have to reallocate divested assets • Could be combined with the role as a single buyer
Allow bypass of NGC by large buyers for new supply	• Increased transparency • Takes volume risk away from NGC • NGC able to aggregate supply from small suppliers if this service is required	• Would require transportation separation & tariff structure development • There would need to be DMO (or similar) on suppliers (~10%) to cover sales to power/steel etc.	• How to ensure that the available gas gets sold to the party willing to pay the most in a shortfall situation? Tender? • NGC presently extracts significant rent from the gas value chain for T&T – how to ensure this continues? Midstream taxation? • May result in NGC stagnation - left with lower-priced contracts in its portfolio.
Transportation services unbundled	• Would result in greater sector transparency	• Separation of transportation and gas supply functions of NGC • Tariff structure development • Regulatory oversight	• Where should the regulatory function sit? MEEA? • Would need to develop Institutional capacity of MEEA
Fully liberalised market	• Removes need for intermediaries	• Breakup of NGC - becomes transportation provider • Open access on the transportation system • Would require DMO for power/steel	• T&T market is not sufficiently deep or liquid to support this option • Not clear how to ensure that all such transactions are arm's length • Opportunity for shifting value along the chain and possibly offshore

1.12.3 Options for LNG

There has been a major issue to T&T in the LNG value chain over recent years where GORTT capture of economic rent from LNG has been far less than for the NGC-supplied ammonia (in particular) and methanol plants, and it is believed that there is substantial value capture offshore, i.e. beyond the T&T tax net.

Although there may be options for GORTT to improve its share of the overall LNG chain take under the existing contractual arrangements, as discussed in Section 1.10, the main forthcoming opportunity for it to do so comes with the expiry of the existing ALNG Train 1 contractual arrangements, which we understand will take place in 2019. As summarised in the figure below there are a number of different options that could be considered for various elements of the value chain.

Figure 1-41 Options for LNG



- Limited gas resource will restrict supply contracts to at most ~ 5 years
- Train 1 will have to compete for supply
- Direct supply from upstream (continuation of existing model); or
- Supply via NGC – more efficient capture of rent by GORTT; increases control over sector

- A merchant plant provides some rent in midstream
- Tolling / Quasi Tolling plant shifts rent to the upstream
- No clear reason to revise business model to achieve GORTT objectives – minimise take by LNG plant

- Limited resource restricts contract term
- Contracts of 2 to 5 years provide certainty but lock in today's pricing formula and could again lead to offshore rent capture
- Marketing through an intermediary and relying on profit may not maximise value for plant
- Tendering is transparent and competitive, and gaining traction in the business

1.12.4 Recommendations & Implementation

1.12.4.1 Dealing with Contractual Shortfalls

The challenge for GORTT is to achieve the appropriate balance between incentivising participants and national welfare. Going forward, regulations to restructure the gas sector must be based on a thorough economic and legal analysis of the relevant contracts. Lacking access to these documents, the following is presented as a generalised discussion of the available options.

Three options have been identified as the means for the reallocation of upstream production in response to a potentially extended period of shortfalls.

- The first option is to continue the management of short supply into consumption as at present, with the volume delivered into the LNG sector as currently determined by bpTT and to a lesser extent BG. NGC would continue to distribute its available gas between its downstream consumers on a pro rata basis.
- The second option is for GORTT to become actively involved in the allocation of gas in the sector, participating in the control of the flow of gas to LNG plants as well as directing the flow of gas within the NGC portfolio. GORTT would need to be actively involved in the decision making around the ALNG / NGC split of gas.
- The third option is also interventionist, but rather than a centrally-planned approach to allocation the short supply would be directed towards the users that would be prepared to pay the highest price. This would entail developing a marketplace for gas with the various buyers bidding for gas volumes.

MEEA has stated that its main policy goal for the energy sector is to ". . . optimally exploit the country's hydrocarbon resources ensuring its efficient administration in order to obtain the greatest returns to the country for the benefit of all citizens." In adhering to this goal, under the interventionist options MEEA would allocate gas according to the value provided to GORTT. The full implementation of the second or third options would entail some form of consultation and rule-making by GORTT, either through the MEEA, or possibly the Fair Trading Commission.

Under the allocation approach, the allocation of gas supply both between ALNG and NGC and within NGC's portfolio would be administered on an annual basis, and as consistently as is possible within the framework of the existing contracts. From a regulatory perspective, this would require the establishment of a mechanism where delivery obligations were limited to annual quantities.

The market-based option would result in the most disruption of existing commercial arrangements. As of a date to be determined, all existing supply contracts would be terminated by an order of GORTT. An administrative marketing centre would be established with all buyers competing at auction for supply on the basis of price. This approach would imply that either NGC's role is reduced to that of transporter or that its wholesale role is expanded to include supply into Atlantic LNG. Given the needs of the gas sector to promote the development of new gas as soon as possible which will require the participation and cooperation of the entire industry it is not possible to see how this approach could be implemented without creating a major upheaval to the sector, regardless of the issues around contracts and legislation.

1.12.4.2 Future Downstream Contracts, Sector Structure & Role of NGC

It is clear that the original drivers behind NGC's adoption of an intermediary / wholesaler role in the T&T gas sector no longer exist. The industry has moved from a growth / development phase of plentiful gas supply where a market-making function was required, into maturity, and is now facing the prospect of a situation under which gas supply is highly unlikely to be sufficient to fully meet demand going forward. Indeed it can be argued that the role of NGC is complicating the operation of the sector as it struggles to match supply with demand and that for large buyers this would be better and more economically efficiently handled by large buyers and sellers interacting directly.

However, from GORTT's point of view the key factor that must be considered is the significant economic rent captured by NGC in the midstream and ultimately distributed back to GORTT as a dividend. If the wholesale margin was passed back to upstream then GORTT would have to share the upside with the upstream suppliers as per the terms of the various upstream agreements. With this in mind, Poten's view is that the uncertain benefits associated with a significant restructuring of NGC's role as wholesaler / transporter are unlikely to be justified the challenges associated with maintaining existing GORTT take levels under a new structure (e.g. by imposing new taxes), and the time and cost associated with implementing what would undoubtedly be a major restructuring exercise. As such we do not believe that allowing the bypass of NGC, unbundling NGC's transportation activities, or fully liberalising the sector will be optimal routes for GORTT to follow.

Rather than maintaining the status quo, Poten's view is that, on expiry of the existing LNG contracts, GORTT should seek to expand NGC's wholesale role to include supply to ALNG, i.e. NGC would buy gas from upstream and sell it to or toll it through ALNG. Although this is very much an interventionist approach, Poten's view is that it is likely to maximise GORTT's overall take from the sector, without compromising the ability of the sector to provide more attractive prices to upstream in order to support new developments. In addition, this option would allow NGC to manage gas supply to the whole downstream sector, whereas at the moment it has limited control of how much gas is supplied to LNG. This is of particular relevance in a gas shortfall situation

Poten's view is also that NGC's business should be refocused on its core wholesale & transportation activities, i.e. its other non-core assets should be divested, potentially either to other existing or new GORTT entities, or to new publicly-owned vehicles. There is no obvious reason as to why NGC is the best undertaker of its non-core roles, such as sector business development, or the best holder of its non-core assets, e.g. upstream production. In particular, these roles create potential conflicts of interest for NGC's core role. This would not preclude the Government continuing to hold these assets, indeed it is recognised that positions in upstream and downstream assets provide valuable information.

NGC appears to have a history of reinvesting earnings for expansion of its commercial presence rather than dividending the revenue back to GORTT. Although this would be largely addressed by paring NGC back to its core activities, GORTT should ensure that NGC dividends back surplus funds to GORTT. Extending NGC's wholesale role will also increase the oversight required of NGC's activities by GORTT to ensure that it is acting in the broadest interests of GORTT rather than its own more limited perspective.

In parallel with expanding NGC's wholesale role to include LNG, Poten recommends that the centrally-planned, allocative approach to future downstream gas contracting is adopted. For the same reasons put forward for the future role of NGC, Poten does not believe that adopting the market-based approach will be in the best interest of T&T. Under the two centrally-planned approaches there are clear attractions to the tendering option which would potentially provide a transparent and fair price discover process. However, our view is that the obstacles to implementing this option (establishing tender parameters between different commodity producers and between plants with different contract expiry dates) will be very difficult to overcome in practice. This leaves the approach under which GORTT determines the downstream consumers that will receive gas as the only viable option.

In terms of implementation, there will need to be an assessment made by GORTT/MEEA/NGC as to how much gas will be allocated to the key consuming sectors, e.g. LNG, ammonia, methanol and steel, as it is unlikely that there will be sufficient gas to fully satisfy demand. This analysis will rely on projections of expected future value to GORTT, which in turn will be highly dependent on projections of future commodity prices, which are inherently volatile and unpredictable. As such, although for example LNG may be projected to provide the highest value to T&T, GORTT may determine that it is in its interest to maintain a broader downstream portfolio in order to insulate itself from future global market changes, i.e. rather than fully filling LNG demand and shutting down various ammonia / methanol plants, GORTT may decide to reduce supply to LNG somewhat in order to maintain supply to ammonia / methanol.

Within the determination of how much gas to be supplied to each sector GORTT/MEEA/NGC will need to decide which plants should receive an allocation of gas and which, if necessary, should be shut down. While it will be a difficult decision to shut down a downstream plant, this will inevitably need to happen over time. If, for example, there is only sufficient gas to keep 50% of T&T's methanol capacity operational it will be far better from an economic perspective to shut down half of the plants and keep the remainder operating at full capacity, rather than keeping all of the plants running at half capacity but with full running costs. It should also be noted that although plants can be mothballed for a period of time and then brought back into operation if gas subsequently becomes available, in practice it will be costly to maintain plants in a mothballed state, keep staff etc.

Based on NGC's contracted upstream gas supply, an assessment will also need to be made for how long NGC can provide downstream gas allocations. Although all of the downstream plants in question will have been fully amortised by the time that their existing gas supply contracts expire, buyers will need some certainty over future gas supply if they are to make investments which may be needed to prolong the life of the plant.

With its expanded wholesale role, experience of managing its existing downstream sales portfolio and share of GORTT's overall gas sector knowledge and expertise, NGC should be well-placed to provide the necessary analysis and recommendations to GORTT/MEEA on downstream gas allocations. However, there should be strict guidelines in place about how allocations should be made, i.e. maximising GORTT take from its gas resources, and GORTT/MEEA should have the ultimate decision-making power regarding any new gas allocations. GORTT/MEEA/NGC will also need to consider the potential allocation of gas to any new industries in parallel with its analysis of allocations to existing users.

1.12.4.3 LNG

Poten's view is that post-expiry of the existing contracts any future gas supply should be routed through NGC to provide an efficient route for GORTT to maximise its take from the LNG value chain.

GORTT should seek to allow the plant a (largely) fixed fee for providing liquefaction services, i.e. in practice a quasi-tolling structure, replicating the existing model for Trains 2/3, with the remainder of the LNG revenues passed back to NGC as the gas supplier. The fixed fee should be set at a reasonable level to provide a return to the Train 1 shareholders and cover their costs, taking into account that the asset has been fully amortised over the initial 20-year operational period.

In terms of LNG marketing, Poten's view is that continuing with the negotiated contracts model once existing contracts expire is unlikely to provide the best value for T&T; it risks replicating the existing issues of offshore value capture. For the same reasons our view is that utilising a marketing entity is not likely to be an optimal approach.

Tendering is a transparent and competitive process which ensures that the best price is realised for sales over the period that is covered by the tender. It is also is gaining increasing traction in the LNG business as the number of market players, shipping / regasification availability, and overall liquidity increases. The tenders could be for spot, short term or long term volumes. However without having access to the Train 1 contracts / agreements, Poten cannot comment on how a tendering process could be imposed on the owners of Train 1.

In terms of implementing a tender process itself, NGC (via its TTLNG subsidiary) has already accumulated substantial experience of short-term LNG sales via its Train 4 offtake. It should be relatively straightforward for NGC to utilise this expertise to oversee any future tendering process for sales from ALNG. Again, there would need to be guidelines in place to manage this, under the ultimate oversight of GORTT/MEEA.

1.13 CONCLUSIONS

1.13.1 Overall

- The gas sector is critical importance to the T&T economy. The actions taken in terms of policies over the next decade will have a profound impact on the financial state of the country and all policy development will need to be carefully considered.
- Natural resources are finite and subject to depletion, they are by definition not sustainable. They represent part of the capital stock of the country and the monetisation of these resources should be for the benefit of the country.
- The Gas Master Plan provides the route map for gas sector development over the next decade. As the gas sector is now moving into a mature phase, it is clear that GORTT focus for this master plan period will need to be one of encouraging incremental gas supply and the maximisation of the value to T&T from the gas produced.

1.13.2 Upstream

1.13.2.1 Gas Supply & Security of Gas Supply

- The relatively low exploration success in the last decade has resulted in a decline of deliverability from producing gas reservoirs as larger fields deplete and increasingly small and marginal fields are brought onstream to fill the supply gap. The decline in available deliverability over recent years has led to increasingly frequent supply shortages to both NGC and ALNG.
- The contractual structures for gas supply to NGC were developed during a time of gas surfeit when flexibility in volume offtake was required by downstream users. The flexibility has now become a problem for NGC in the face of constrained supply. The absence of penalties imposed on suppliers for shortfalls in contracted gas deliveries appears to have led to a disproportionate curtailment of gas supply to NGC by upstream suppliers in favour of ALNG in times of shortfall.
- There is no requirement or financial incentive for suppliers to maintain excess deliverability (swing or cushion gas) which would allow them to compensate for supply reductions in other parts of the production system.
- As the gas system approaches the end of plateau production, deliverability will depend on depleted mature fields and an increasing number of small field developments which will typically have high depletion rates and limited excess deliverability.
- Gas storage is unlikely to be a solution to the security of supply issue for a gas industry that has little seasonal and diurnal fluctuation. Studies undertaken by NGC indicate show that such a project would have limited impact upon managing supply. The fundamental issue for T&T is to mobilise investment on increasing offshore deliverability in order to avoid shortfalls occurring, as swing gas will be less costly than storage.

1.13.2.2 Gas Infrastructure

- There is adequate capacity in the gas transportation system but it is ageing and will require continued investment to ensure integrity.

1.13.2.3 Gas Reserves

- The total proven natural gas reserves in T&T have been in decline over the last decade as the rate of reserves additions has failed to keep pace with production. Proven reserves peaked in 2002 at approximately 20.8 Tcf but had declined to 12.2 Tcf at the end of 2013. The total unrisked proven, probable and possible reserves base is 23.9 Tcf. The R/P ratio for proven reserves was 8.3 years at the end of 2013 down from around 20 years in 2004. The diminishing R/P ratio indicates a need to focus on encouraging exploration.
- Much of the prospective resource volumes are in small fields, an expected 6.3 Tcf across 151 prospects with an average success volume of 250 Bcf. The prospectivity of many of these fields will depend upon their proximity to existing infrastructure and securing access to that infrastructure.
- A review of operator development plans indicates that gas supply rates of circa 3.85 Bcf/d (average) are likely to persist in the coming years and are a realistic expectation of future supply. This equates to a sales gas figure of ~3.7 Bcf/d, i.e. .there will not be sufficient gas to reach the ~4.3 Bcf/d required to fully supply the downstream industry. Beyond 2017 gas supply is increasingly dependent on offshore projects which are as yet not sanctioned for development. The heavy reliance on post-2017 unsanctioned projects emphasises the importance of rapidly getting these projects to sanction.
- The timing of any supply from cross-border fields which extend into Venezuelan territory relies on the outcome of government to government discussions. Only 27% of the largest field (Manatee Loran) lies in T&T waters but for any significant extension of plateau production the entire field would need to be processed through T&T infrastructure
- A combination of moderate deepwater success and some gas production from cross border fields would provide support to extend plateau or reduce the rate of production decline post 2025. If there has been no deepwater exploration success by 2018 or significant progress in cross-border discussions with Venezuela by 2020 then the industry should prepare for a further decline in long-term gas supply levels.

1.13.2.4 Mobilising Production

- Our economic analysis indicates that incremental and new developments under older PSC terms and shallow-water greenfield projects and incremental projects will require fiscal assistance and/or gas prices in excess of $3/MMBtu.
- Access to production and transportation infrastructure will be a key issue in mobilising incremental development the need for which will only increase as production from the shallow-water area continues to mature. Existing pipeline networks cross a significant number of open acreage blocks. Interest in exploring these areas would be increased if there was greater clarity on the terms of access to existing infrastructure in the event that exploration of those areas proves successful.
- The key challenge for T&T is to incentivise enough exploration activity in deepwater blocks in an early enough timeframe to ensure that any gas present is developed in time to backfill the shallow-water production profile. Success in the first work period would encourage operators to pursue subsequent phases but current contracts would deliver a maximum of only 22 wells over the full exploration program. This is an area where GORTT should stimulate additional activity.

- Supply from the cross-border fields relies on the outcome of government to government discussions which have been in progress for many years. The emergence of gas supply shortages in recent years, together with the understanding that even the current reduced production plateau will not extend beyond 2025, has provided a clear imperative for T&T to progress these discussions towards an agreement to develop the gas. There is a window of opportunity to process gas through existing consumers as shallow-water gas production declines in the mid-2020s.

1.13.3 Downstream

1.13.3.1 Markets

- T&T has developed a major gas export industry both directly, in the form of LNG, and indirectly through gas-based petrochemicals (ammonia/urea, methanol). The sale of these products collectively account for ~86% of the gas consumption in T&T of which ~55% is utilised in LNG.
- The market demand for these products are continuing to grow but T&T's competitive advantages (the low cost of the gas resource and the proximity to the world largest market, the US) have been eroded over time as incremental gas supply from T&T has become more expensive and the US market is now saturated with gas. T&T petrochemical exports will be competing for market share against products from other supplier countries in more distant markets.
- GORTT has elected to provide power at a highly subsidised price as a means of distributing the wealth generated from the energy sector to the wider population. RIC sets the price at which T&TEC sells power to different classes of consumer. In order to sustain T&TEC financially NGC sells it gas at a current price of around $1.35/MMBtu, with inflation escalation. This has caused major distortions in the gas value chain as the price is below the economic cost of production of many of the upstream suppliers. This situation is managed by NGC. This is problematic; the low price of power does not encourage energy efficiency. The low gas price also diminishes the incentive and the ability of T&TEC to invest in more efficient generation capacity.

1.13.3.2 Commercial Arrangements & Value Generation

- Over the last decade GORTT has derived the greatest benefit from its natural gas resources through ammonia exports. The returns from LNG have been relatively poor compared to those from ammonia and, to a lesser extent, methanol. The relatively poor performance of LNG has not been due to inherently poor market conditions but rather from the particular marketing arrangements that have been in place for LNG. Under different arrangements GORTT take from LNG would have been at least as high as from ammonia. Given the relative size of LNG exports it is clear that improving the value from LNG should be a high priority for GORTT.
- GORTT realises significant economic rent through the aggregation role played by NGC in supplying the downstream.
- Netback prices from existing LNG arrangements are projected to remain relatively low. However, based on our price projections and under revised LNG arrangements post-expiry of existing contracts, LNG is could be the most attractive of T&T's existing gas monetisation

options. The expiry of the existing ALNG Train 1 agreements in 2019 presents an opportunity for the GORTT to realise this potential value.

1.13.3.3 Gas & Supply Demand Situation

- The overall gas supply to downstream industries has declined somewhat since peaking in 2010. This has been due to lower supply from upstream producers due to reduced deliverability and protracted maintenance periods. As a result all export-based industries have seen gas supply availability declines.
- NCG appears to be in a comfortable position in terms of contracted gas supply. However, actual supply to NGC from upstream (~1.6 Bcf/d in 2014) has been well below contracted supply (~2.1 Bcf/d).
- A key issue is that although all major downstream industries have experienced declining gas supply availability, overall gas supply to LNG has largely been maintained at contractual levels (average supply was around 2% below contracted levels of ~2,212 MMcf/d for ALNG in 2011, 2012 and 2014) while overall gas supply to NGC has not. This in turn has left NGC short of gas to supply its downstream customers.
- T&T has a current downstream portfolio that could consume an estimated ~4.3 Bcf/d. This demand is presently not being fully met and based on our supply demand analysis it is not realistic to expect that it will be met in future on a long-term basis (under the most optimistic supply forecast demand could be fully for a period of ~3 years from 2019). Indeed the current shortfall situation will continue.
- If production from presently unsanctioned developments under the most recent PSC terms is mobilised there would be sufficient gas to meet downstream contractual commitments, but not to meet demand. These projects would also only provide limited volumes/durations for expiring downstream contracts to be extended from 2019. Extending expiring downstream contracts well into the 2020s will require substantial unsanctioned production under the more economically-challenged old PSC terms.
- While gas supply is likely to available from 2019 to extend supply contracts to existing downstream industries, it is highly likely that gas supply will be insufficient to fully meet demand and as such decisions will have to be taken over which contracts to extend and which downstream industries to shut down. In the absence of large volumes of incremental supply, directionally the gas sector will need to focus on arrangements to achieve higher gas prices and greater efficiency in the existing plant and production facilities, i.e. a focus on developing value rather than growth.
- Given the prevailing gas shortfall situation the development of new projects will need to be carefully considered. It is clear that the sanctioning of any gas supply to new downstream ventures will come at the expense of supply to existing operating assets, i.e. if a new plant is developed then it is likely that an old plant will have to be shut down. Old plants are amortised and in general the costs of investment in a new plant are likely to far outweigh the effects lower operating efficiency likely to be found in an older plant.
- The shortfall situation the NGC experiences in supply from the upstream is passed on to the downstream and is managed by NGC by applying generally pro rata cuts to the downstream industries, but maintaining supply to the domestic sector. Contractually NGC avoids penalties in contracts by declaring Force Majeure.

1.13.4 Future Mid & Downstream Sector

1.13.4.1 Prioritisation / Allocation of Gas

- Existing shortfalls have been managed by control of the gas supply split between NGC and ALNG by bpTT and to a lesser extent BG, and NGC managing the supply to its downstream industries (generally) imposing cuts on a pro rata basis. NGC's position has been that gas supply shortfalls are short-term phenomena and that following a shortfall there will be a reversion to full supply. Indeed expiring downstream contracts have been renewed by NGC at their existing ACQ levels. The existing contractual shortfall situation through to at least 2016 and its potential future extension is such that there will be a need for active management of supply into consumption.
- GORTT should be seeking to maximise the value received from the gas produced, which in an environment where demand cannot fully be met means directing gas towards the plants that offer the highest value for the resource. This is not happening under the present system of all contracts being extended without apparent analysis of their relative value to GORTT.
- There are interventionist approaches that GORTT could potentially take to manage the contractual shortfall situation by diverting gas to higher value end users, although the parties impacted may not be willing to accept such moves and may contest them legally.
- Given that it would not appear feasible for NGC to extend any of its contracts that expire before 2019, a more selective approach to downstream contract renewals will inevitably be required in future. GORTT has several options ranging from a market-based approach through to central planning.

1.13.4.2 Sectoral Structural Issues & the Role of NGC

- NGC is the only, player in the midstream sector and covers a multitude of roles, not just in the midstream but across the whole hydrocarbon sector: monopoly wholesaler / aggregator; transmission owner / operator; owner of E&P, LNG and gas processing assets; LNG offtaker; and gas industry business development.
- There are issues related to the existing roles of NGC; no formally defined regulation of NGC; potential conflicts of interest, lack of transparency, aggregation management proving increasingly challenging; the overall GORTT know-how of the sector is highly concentrated in NGC.
- There are a number of options for GORTT for managing the structure of the sector and the role of NGC: no change; NGC wholesale role expands to include LNG (from expiry of existing contracts); NGC business refocused on core activities (wholesaling and transmission); allowing bypass of NGC for large buyers; unbundling transportation services; and fully liberalising the market. However, the depth and breadth of the T&T gas industry is not sufficient for the development of a competitive market.
- From GORTT's point of view the key factor that must be considered is the significant economic rent captured by NGC in the midstream and ultimately distributed back to GORTT as a dividend. If the wholesale margin was passed back to upstream then GORTT would have to share the upside with the upstream suppliers as per the terms of the various upstream agreements.
- Poten's view is that the uncertain benefits associated with a significant restructuring of NGC's role as wholesaler / transporter are unlikely to be justified by the potential reduction

in GORTT take, the challenges associated with maintaining existing GORTT take levels under a new structure (e.g. by imposing new taxes), and the time and cost associated with implementing what would undoubtedly be a major restructuring exercise. As such we do not believe that allowing the bypass of NGC, unbundling NGC's transportation activities, or fully liberalising the sector will be optimal routes for GORTT to follow.

1.13.4.3 Options for LNG

- GORTT capture of economic rent from LNG has been far less than for the NGC-supplied ammonia (in particular) and methanol plants, with substantial value leakage offshore, i.e. beyond the T&T tax net.
- Although there may be options for GORTT to improve its share of the overall LNG chain take under the existing contractual arrangements, the main forthcoming opportunity for it to do so comes with the expiry of the existing ALNG Train 1 contractual arrangements in 2019. There are a number of different options that could be considered for various elements of the value chain. The key issue to address is the marketing arrangements for LNG.

1.13.5 Institutional Issues

1.13.5.1 Policy

- There is at present no approved policy covering the gas sector for the master plan period. The MEEA draft Green Paper sets out the objectives for the energy sector and has a number of policy goals related specifically to the gas sector. However, it is not a GORTT-approved document.
- The local content policies developed in T&T are focussed on placing contracts with T&T entities rather than on local value added. There is an absence of visibility to ensure compliance with objectives for local participation in the energy sector and a lack of monitoring and auditing of local content targets. Overall, local content policies are not integrated in GORTT's regulatory activities of the sector and specifically, there is an absence of a well-defined monitoring and measurement system that focusses on local value added.

1.13.5.2 Sector Regulation

- The GORTT lacks an effective institutional and regulatory framework for administering the natural gas subsector. The main piece of legislation was adopted in 1962 to regulate the exploration and production of crude oil. Technical licensing regulations have been adopted for natural gas facilities, but no oversight is applied to commercial monopolies and supply obligations. Information on the amount of revenue derived from the natural gas subsector is not separately accounted for.

1.13.5.3 Fiscal Regime

- The fiscal terms in T&T have evolved significantly. In the 1970s PSCs were introduced in addition to existing EPLs. Under the PSC regime, GORTT take was based on the allocation of a share of production thresholds rather than the fixed royalty under the EPL. This mechanism was changed in the 1990s to a 'matrix' that takes into consideration prices as well as production levels. The increase in state-take under the PSC was off-set by a provision that committed the Minister to pay royalties and other taxes assessed on PSC operations from his share of the profit petroleum.

1.13.5.4 Institutional Capacity

- The next 10 years for the T&T gas industry will be a period where there will need to be significant intervention by the GORTT in both upstream and downstream sectors. This will impose a significant burden upon MEEA, an organisation which is already facing challenges in retaining qualified personnel to manage the affairs for the state.

1.14 RECOMMENDATIONS

1.14.1 Upstream

1.14.1.1 Gas Supply and Security of Supply

- For new upstream supply contracts NGC should ensure that there are "failure to deliver" clauses so that suppliers are obligated to supply a given volume and will be penalised if they fail to do so. However, it is noted that continuity of supply has a value that has not to date been reflected in the gas prices and that higher prices are a corollary to this action.
- Supply interruptions have increased in recent years as the deliverability of large foundation fields falls as they are depleted. While new fields have been developed to replace lost production capacity, they are smaller and do not have the large excess well capacity of the larger fields. The newer fields are therefore unable to make up for temporary supply shortfalls elsewhere in the system due to planned and unplanned shutdowns. The impact of planned shutdowns can be addressed to some extent by better planning of maintenance programmes between producers to avoid too many production sub-systems being off line for maintenance at any given time. However, the system will still be exposed to unplanned shutdowns. The underlying cause is a system-wide reduction in deliverability as older prolific fields are replaced by smaller fields with less spare deliverability. Increasing system deliverability requires investment, primarily in additional wells or field compression, given that gas treatment and transportation systems have demonstrated sufficient capacity in the past. This could take the form of accelerating current development plans to increase short-term production capacity before existing fields decline. Producers can be incentivised to do this by:
  - Requiring excess deliverability in new supply.
  - Offering an additional tariff for maintaining reserve capacity.
  - Paying a premium for uninterruptible gas.

1.14.1.2 Mobilising Upstream Development

- Maintenance of a plateau production rate of 1.4 Tcf/y (3.85 Bcf/d) requires that a high proportion of unsanctioned projects proceed as planned. A hybrid approach to this goal is recommended, consisting of an initial realignment of fiscal and other regulations to remove inconsistencies between terms awarded over the last two decades, combined with flexibility for the regulator to provide support to specific developments that cannot progress even under the revised terms. The initial realignment of regulations should include:
  - Maximising access for new developments to existing infrastructure to reduce costs.
  - Review and updating of fiscal terms (covering profit split and cost recovery) in 1996-05 gas price indexed PSCs to provide new developments with terms similar to the 2011-12 PSCs.
  - Review and updating of fiscal terms in production license areas to ensure they provide a comparable investment return for new projects to recent PSC terms.

- A transparent and easily administrated approach will also be required to the application of incentives for fields that remain marginal covering both additional fiscal support and flexibility in offered gas prices. This will require case-by-case assessment of the merits of marginal projects.

- In regard to deepwater developments the focus for T&T at this stage should be to expand the number of blocks under license with firm drilling commitments. This will be challenging in the current environment of reduced expenditure across international oil and gas companies, however opportunities for stimulating increased activity should be explored including:
  - State-sponsored seismic acquisition.
  - Review of fiscal terms and alignment between GORTT and operator incentives.
  - Road shows to advertise new fiscal terms and seismic data.

- In regard to cross-border gas it is recommended that further initiatives are taken:
  - Setting clear deadlines and timelines within GORTT for progress of the discussions with Venezuela.
  - Comprehensive evaluation of the value to T&T of securing an arrangement whereby 100% of produced gas is processed through their existing infrastructure, to allow specific value propositions to be formulated and when appropriate presented to the Venezuelan government.
  - Consideration of how agreement to develop the gas reserves could form part of a broader bilateral agreement with Venezuela.

1.14.1.3 Access to Infrastructure

- Access to existing infrastructure will be essential to mobilise incremental resources. The challenge for the regulator is to create the conditions in which spare capacity in existing upstream infrastructure is made available to other developers under reasonable commercial terms to stimulate exploration and production investment. The success of the relatively unintrusive UK North Sea approach of an Industry Code of Practise, supported by a regulator willing to intervene in the national interest in exceptional circumstances, presents a compelling model for T&T. This regime relies on negotiation of commercial arrangements between the infrastructure owner and the third party for access with the threat of government intervention if terms cannot be agreed. It is considered that this can be implemented without changing existing legislation and that GORTT intervention could be enforced where necessary under the rule-making authority granted to the President either by direct regulation under Section 29 (1) (c), or by delegation to the Minister under Section 29 (1) (o) of the Petroleum Act.

1.14.2 Downstream

1.14.2.1 Markets

- GORTT should establish a power price that at least reflects the cost of service of supply. This would encourage more efficient energy use and bring greater revenues to T&TEC. In the short term it would reduce the amount of power required and the amount of feed gas and in the longer term provide the incentive and ability for T&TEC to invest in more efficient generation capacity. Regarding the subsidy, it would be more effective for GORTT to more directly target the poor by making direct payments through welfare support or, as a second best option, limiting the amount of electricity that qualifies for the low electricity price. Users consuming more than the qualifying amount would pay a higher price on the excess, which should be set at a level to cover the cost of the subsidy.

1.14.2.2 Commercial Arrangements & Value Generation

- GORTT market focus should initially be on attempting to improve the value received from LNG exports. Although recognising that there are existing commercial arrangements in place MEEA should:
  - Undertake a detailed review of the project contracts and LNG marketing arrangements to see where action could potentially be taken. For example, there may be terms in the Project Agreements for the various LNG trains under which action could be taken to change the approach of various LNG offtakers, e.g. a requirement to maximise value under the LNG offtake arrangements. It will be necessary for GORTT to take legal advice on the extent to which any of the options identified are likely to succeed.
  - Investigate the possibility of tax authority action on realised prices. The Petroleum Pricing Committee has been identified as a potential mechanism to impose deemed pricing for tax purposes, bringing more revenue under the GORTT tax umbrella. This needs to be investigated further by MEEA. Again, it will be necessary for GORTT to take legal advice on the extent to which this is likely to succeed.
  - Stimulate LNG offtakers into action by putting the reality of T&T's take from the LNG industry into the public domain, or at least threatening to do so (the general perception in T&T appears to be that LNG provides very good value for T&T's gas and there does not appear to be any widespread awareness of the value loss issues that have been described).
  - Closely scrutinise future LNG sales to attempt to better hold offtakers to account where there appear to be deviations in value from prevailing market conditions. MEEA should insist that all ALNG revenue is reconciled on a cargo-by-cargo basis in the data that it receives from ALNG, so that it can be properly understood and evaluated. MEEA should also insist that any costs included in the LNG prices are fully itemised and explained such that they can be properly scrutinised. MEEA should undertake ongoing analysis of this data as it is received to understand where the main areas of value loss are versus prevailing market conditions, i.e. which offtakers, which contracts, which end markets etc. This will put MEEA into a stronger position to challenge the activities of the offtakers and possibly prompt revised marketing behaviour that is more in the interests of T&T.

1.14.3 Future Mid & Downstream Sector

1.14.3.1 Prioritisation / Allocation of Gas

- There are interventionist approaches that GORTT could potentially take to manage the contractual shortfall situation by diverting gas to higher value end users, although the parties impacted may not be willing to accept such moves and may contest them legally. GORTT needs to investigate the options available to it in dealing with shortfall management and the extent to which it is able to guide supply in a shortfall situation, including LNG and NGC's downstream portfolio. This will require a review of the conditions of each PSC, EPL, investment/project agreement, gas supply and LNG export supply contract to investigate such options, e.g. can the PSC TCM meetings be used to influence the gas supply split between NGC and LNG?, would the adoption of interventionist options by GORTT conflict with obligations under either the PSC or the EPL?, are there stability clauses in the PSCs that would limit GORTT's scope of action? GORTT will need to take legal advice on the likely consequences of implementing interventionist approaches to prioritise supply. For example, it will need to consult with the Office of the Attorney General regarding the application of T&T's jurisprudence on the nature of compensable property interests, if the parties affected could potentially claim a form of confiscation, expropriation or nationalisation.

- Following a commercial and legal review of the options for GORTT to intervene in gas allocations, GORTT requires a clear strategy during the transition period in which existing supply contracts direct with ALNG Trains 2-4 remain in force in parallel with the recontracting of supply to petrochemical consumers through NGC (and potentially ALNG Train 1). In particular this should address how supply shortfalls are allocated across old and new (Ship or Pay) contracts, i.e. can GORTT enforce supply diversion away from ALNG Trains 2-4 under the existing contracts in order to maximise its value from the gas sector, if this is deemed the optimal approach?

1.14.3.2 Future Downstream Contracts, Sector Structure & Role of NGC

- Rather than maintaining the status quo of direct gas supply contracting between upstream and ALNG, Poten's view is that, on expiry of the existing LNG contracts, NGC's wholesale role should be expanded to include ALNG, i.e. for new gas supply to ALNG NGC would buy gas from upstream and sell it to or toll it through ALNG. NGC would also continue this wholesale role for supply to methanol and ammonia. Although this is very much an interventionist approach, Poten's view is that this approach is likely to maximise GORTT's overall take from the sector in future, due to the significant economic rent that is captured by NGC in the midstream and ultimately distributed back to GORTT as a dividend. This expanded role would not compromise the ability of the sector to provide more attractive prices to upstream in order to support new developments as NGC would be able to provide LNG-linked pricing to upstream suppliers if this was deemed necessary to support new upstream developments. It could also provide gas pricing to upstream linked to a basket of LNG, methanol and ammonia prices.
- In addition, this option would allow NGC to manage gas supply to the whole downstream sector, whereas at the moment it has limited control of how much gas is supplied to LNG. This is of particular relevance in a gas shortfall situation
- Future gas contracting should conform to industry best practice with enforceable delivery obligations between NGC and both gas suppliers and buyers.
- Poten's view is also that NGC's business should be refocused on its core wholesale & transportation activities, i.e. its other non-core assets should be divested, potentially either to other existing or new GORTT entities, or to new publicly-owned vehicles. There is no obvious reason as to why NGC is the best undertaker of its non-core roles, such as sector business development, or the best holder of its non-core assets, e.g. upstream production, PPGPL. In particular, these roles create potential conflicts of interest for NGC's core role. This will allow NGC to operate without conflicts of interest or bias through a time when there will be many difficult decisions to be made in regard to the allocation of gas.
- NGC appears to have a history of reinvesting earnings for expansion of its commercial presence rather than dividending the revenue back to GORTT. Although this would be largely addressed by paring NGC back to its core activities, GORTT should ensure that NGC as a rule automatically dividends back surplus funds to GORTT. Extending NGC's wholesale role will also increase the oversight required of NGC's activities by GORTT to ensure that it is acting in the broadest interests of GORTT rather than its own more limited perspective.

- In parallel with expanding NGC's wholesale role to include LNG, Poten recommends that a centrally-planned, allocative approach to future downstream gas contracting is adopted. For the same reasons put forward for the future role of NGC, Poten does not believe that adopting the market-based approach will be in the best interest of T&T. Under the two centrally-planned approaches there are clear attractions to the tendering option which would potentially provide a transparent and fair price discover process. However, our view is that the obstacles to implementing this option (establishing tender parameters between different commodity producers and between plants with different contract expiry dates) will be very difficult to overcome in practice. This leaves the approach under which GORTT determines the downstream consumers that will receive gas as the only viable option.

- In terms of implementation, there will need to be an assessment made by GORTT/MEEA/NGC as to how much gas will be allocated to the key consuming sectors, e.g. LNG, ammonia, methanol and steel, as it is unlikely that there will be sufficient gas to fully satisfy demand. Within the determination of how much gas to be supplied to each sector GORTT/MEEA/NGC will need to decide which plants should receive an allocation of gas and which, if necessary, should be shut down. With its expanded wholesale role, experience of managing its existing downstream sales portfolio and share of GORTT's overall gas sector knowledge and expertise, NGC should be well-placed to provide the necessary analysis and recommendations to GORTT/MEEA on downstream gas allocations. However, there should be strict guidelines in place about how allocations should be made, i.e. maximising GORTT take from its gas resources, and GORTT/MEEA should have the ultimate decision-making power regarding any new gas allocations.

- GORTT/MEEA/NGC will also need to consider the potential allocation of gas to any new industries in parallel with its analysis of allocations to existing users. Given that there is existing unfulfilled demand for gas from existing amortised plants there is no justification for T&T to offer tax holidays or other incentives for new plants. They must be able to compete on full cost basis to be approved.

- In summary, Poten's view is that NGC should:
  - Continue to act as the monopoly buyer of gas from upstream, gas transporter and wholesale supplier of gas to the methanol and ammonia industries.
  - Expand this role to include gas supply to LNG on expiry of the existing gas supply/LNG sales contracts.
  - Be forced to divest its non-core assets, e.g. upstream production.
  - Be forced to automatically dividend back surplus funds to GORTT.
  - Provide the necessary analysis and recommendations to GORTT/MEEA on future downstream gas allocations, with GORTT/MEEA making any final decisions.

1.14.3.3 LNG

- Poten's view is that post-expiry of the existing contracts any future gas supply should be routed through NGC to provide an efficient route for GORTT to maximise its take from the LNG value chain.

- In terms of LNG marketing, Poten's view is that continuing with the negotiated contracts model is unlikely to provide the best value for T&T; it risks replicating the existing issues of out of the market price and offshore value capture. For the same reasons our view is that utilising a marketing entity is not likely to be an optimal approach. Tendering is a transparent and competitive process which ensures that the best price is realised for sales over the period that is covered by the tender. It is also is gaining increasing traction in the LNG business as the number of market players, shipping / regasification availability, and overall liquidity increases. As such, Poten's view is that this is the route that T&T should follow for future LNG sales to avoid the issues under the existing arrangements.

- In terms of implementing a tender process itself, NGC (via its TTLNG subsidiary) has already accumulated substantial experience of short-term LNG sales via its Train 4 offtake. It should be relatively straightforward for NGC to utilise this expertise to oversee any future tendering process for sales from ALNG. Again, there would need to be guidelines in place to manage this, under the ultimate oversight of GORTT/MEEA.

1.14.4 Institutional

1.14.4.1 Policy

- GORTT through MEEA should establish a clear energy policy which contains specific objectives in regard to future gas sector development and operational activity for the next decade. The first step in this process is to prepare a new Energy Green Paper that should take into account the policy options and initiatives developed in the Master Plan. This document should provide a clear pathway forward identifying Government intentions in regard to the operation and oversight of the sector.

1.14.4.2 Gas Sector Regulation

- With the exception of upstream exploration and production, the natural gas sector in T&T is largely unregulated and left to function under a series of commercial agreements that allocate production to either internal or external markets. If the gas sector were still expanding it would be prudent to consider establishing an independent regulatory function. However, given the specific problems that the industry will face over the next few years and recognising that MEEA is already short of experienced resources, the establishment of an independent regulatory function, the recruitment of competent staff and the development of processes and procedures over the next five years would be an immense challenge and is likely to be a major distraction for the most immediate tasks at hand such as mobilising incremental gas supply.
- At this point in time rather than attempting to establish an independent downstream regulator for the gas sector, as many governments have done, Poten recommends that MEAA should retain its current role in setting policy and establishing the standards for industry performance regarding competition, curtailment planning and facility access, and that NGC should maintain its role as aggregator and gas transporter. At the same time, administration of the gas sector requires that industry and GORTT are intrinsically linked through a competent authority (NGC) that can provide a more finely-tuned level of operational and market oversight.
- In recommending keeping NGC in this critical role of gate keeper and clearing house in the centre of the gas industry there are two critical conditions:
  - That the upstream and downstream interests currently held by NGC are divested, and
  - NGC's role of aggregator and transporter is performed as a statutory body. This approach is intended to ensure that gas trading and transportation functions are conducted according to clear rules, without the distractions of external political and commercial agendas that burden state-owned holding companies. NGC would report

to the Minister, who would be responsible for appointing its board of directors according to clear criteria for their experience and competence.

1.14.4.3 Institutional Capacity

- Given the increased burden that will be placed on MEEA / NGC and the difficulties faced in attracting qualified personnel from the industry, there will inevitably be a need to use outside expertise going forward in dealing with upstream and downstream issues. There is also the possibility of utilising secondees from the various operating companies in certain areas which are not commercially sensitive. A number of companies have indicated their willingness to support GORTT in this way.

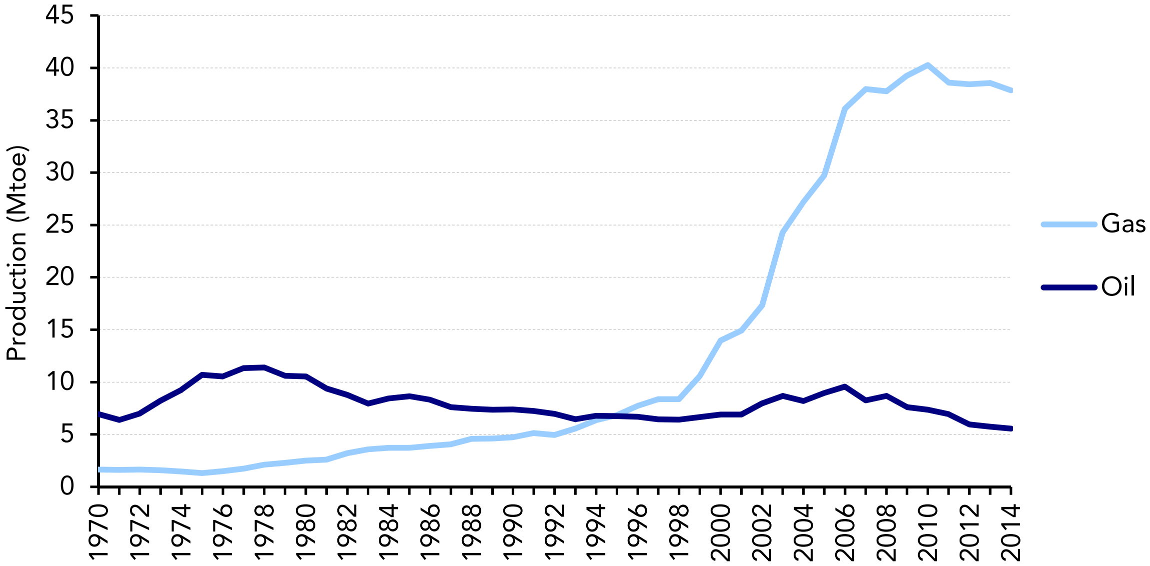
2.1 BACKGROUND

2.1.1 Historical Context of Natural Gas in Trinidad & Tobago

The Republic of Trinidad and Tobago (T&T) is a well-established hydrocarbon province and has been a producer of oil and gas for over a century. Oil was first discovered in Trinidad in the late nineteenth century and commercial production started in 1908. It was not until 1953 that associated gas was first commercially utilized in Trinidad fuelling a power station at Penal. The critical point for the development of the gas industry was the discovery by Amoco in 1968 of large volumes of non-associated gas off the east coast of Trinidad.

Figure 2-1 Historical Oil and Gas Production in T&T

(source: BP Statistical Review of World Energy 2015)



With the discovery of more gas reserves off the east coast of Trinidad in the 1970s, the Government of the Republic of Trinidad and Tobago (GORTT) began to implement strategies for the development of the natural gas sector. The Point Lisas Industrial Estate (PLIE) was established on the west coast of Trinidad to accommodate gas-based industries. The National Gas Company of Trinidad and Tobago (NGC) was formed in 1975 and the PLIE development was started. The 1980s saw the development of gas infrastructure and new gas-based industries, providing ammonia and methanol production.

The 1990s saw further gas sector development with the first train of Atlantic LNG (ALNG) delivering its first cargo in 1999. Also in the 1990s a DRI steel plant was developed at PLIE further diversifying the county's industrial base. By the late 1990s gas production exceeded oil production on a barrel of oil equivalence (boe) basis and the economy has moved from oil based to largely gas based. The 2000s saw further development of the ALNG plant, additional ammonia and methanol plants and the construction of additional gas transportation infrastructure.

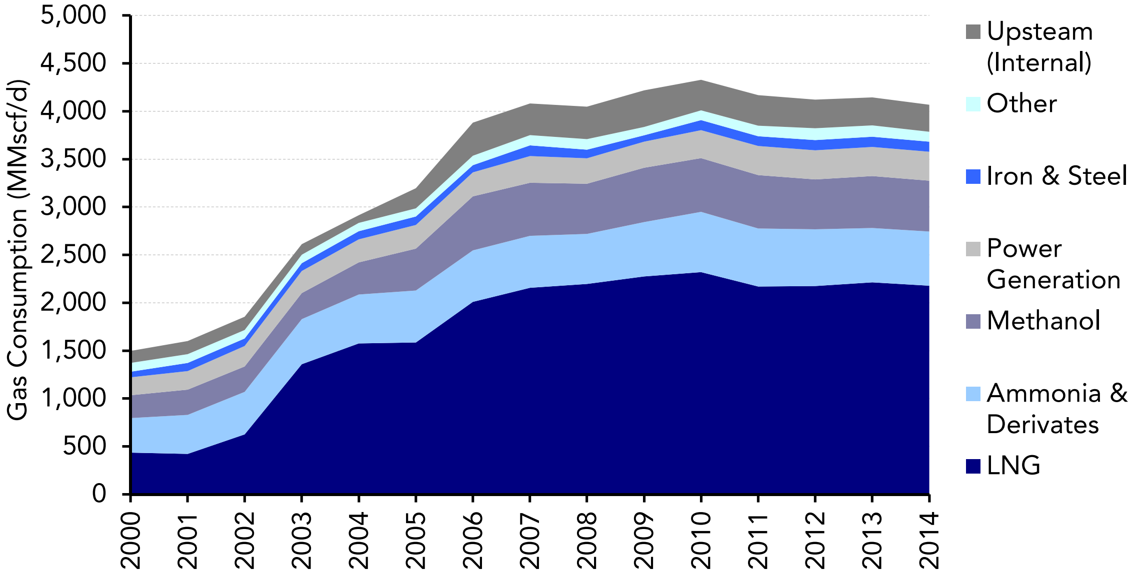
Table 2-1 Chronology of Selected Gas Developments in T&T

(source: NGC, MEEA)

Year	Event
1953	Gas used for power generation in Penal
1959	First ammonia plant (WR Grace) start up
1968	Amoco discovers large gas reserves off east coast
1975	Best use of natural gas resources conference held, NGC established
1977	Start-up of Tringen 1 ammonia plant
1980	ISCOTT DRI steel production start up
1981	Startup of PCS Nitrogen 1&2 ammonia plants at PLIE
1983	Start-up of first urea plant at PLIE (PCS Nitrogen)
1984	Start-up of TTMC (M1) the first methanol plant at PLIE
1991	Phoenix Park Gas Processors Limited (PPGPL) gas processing plant commissioned
1993	Development of CMC; Farmland MissChem; Ispat; Nucor; Cliffs downstream industries
1996	PCS 03 ammonia plant start up
1997	Nucor Iron carbide plant start up
1998	PCS 04 ammonia plant start up
1999	Titan methanol plant start up, ALNG T1 start up, Cliffs HBI steel facility starts up
2002	CNC 1&2 ammonia plants start up, ALNG T2 start up
2003	ALNG T3 start up
2004	Atlas methanol plant start up
2005	Completion of 56" Cross Island Pipeline (CIP), M5000 methanol plant start up, ALNG T4 start up
2009	AUM urea complex starts operations
2011	Completion of gas pipeline to Tobago

The build-up of gas consumption since 2000 is shown in Figure 2-2 overleaf. According to Ministry of Energy and Energy Affairs (MEEA) statistics, in 2014 the majority of gas production, 53.5%, was used by ALNG with the largest other consumers being the ammonia (13.9%) and methanol (13.1%) sectors. The power sector consumed 7.4% of gas production, followed by the iron/steel sector (2.6%) and other consumers (refinery, cement, gas processing, small consumers) (2.5%). Internal gas consumption in the upstream sector was 6.9% of production in 2014.

Figure 2-2 Gas Consumption by Sector
(source: MEEA)



This graphic clearly shows the relatively large scale of LNG developments in terms of overall gas demand and T&T was the world's sixth largest exporter of LNG in 2014. Until the large-scale development of shale gas in the US, T&T supplied ~60% of US LNG imports. However, T&T's LNG exports are now primarily destined for Europe, the Americas and Asia, and in 2014 T&T LNG was exported to 23 different countries.

T&T is also the world's largest exporter of methanol and ammonia. The country has historically relied upon the markets of North America for a significant share of the petrochemical exports. The domestic utilization of shale gas in North America will result in import substitution of these products and the producers will need to seek new markets for the product.

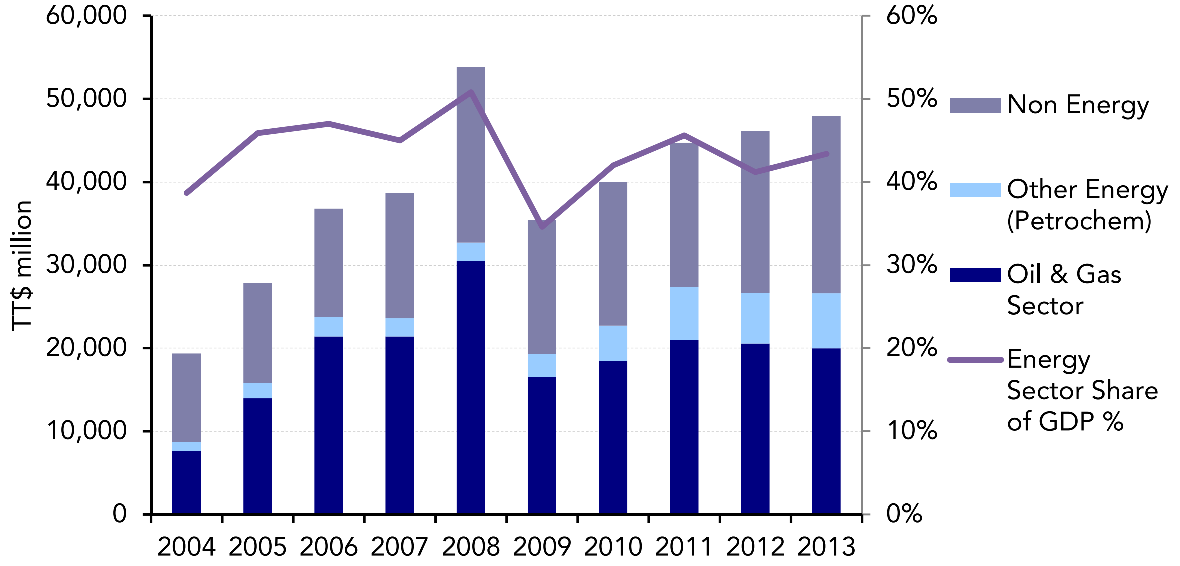
Upstream gas production in T&T is concentrated, with four producers presently accounting for over 95% of production: bpTT, BG, EOG Resources and BHP Billiton.

2.2 THE ENERGY SECTOR'S PLACE IN THE T&T ECONOMY

2.2.1 Contribution to GDP

T&T's economy is highly dependent on the energy sector which, in the period 2004-2013 accounted for, on average, 43% of national GDP and around 54% of GORTT tax revenues and was responsible for around 85% of exports. The tax revenues from the sector have grown with the development of gas utilisation over the last decade, as can be seen in Figure 2-3 below. The T&T economy has a greater industrial base compared to its neighbours. In contrast to most other Caribbean states the tourism sector plays a minor role in T&T, contributing only around 1% to national GDP.

Figure 2-3 Tax Revenues from Energy Sector & Share of GDP 2004-2013
(source: Ministry of Finance)



T&T's energy sector is dominated by gas production, which today accounts for almost 90 percent of total oil and gas production (on a boe basis).

The latest IMF consultation report (2014 Article IV Staff Consultation) identified the key role that the energy sector is expected to play through the next 5 years to 2019, where it is projected to continue to contribute around 50% of GoRTT revenue, although this is expected to fall towards the end of the period.

Table 2-2 IMF Medium Term Macroeconomic Framework (Baseline Scenario)

(Source IMF Article IV Staff Consultation September 2014)

					Est.	Forecast					
	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Real GDP Growth	-4.4	0.2	-2.6	1.2	1.6	2.3	2.1	1.9	1.8	1.8	1.7
Energy	-1.8	3.2	-3.9	-1	0.2	2	1.4	1	0.9	0.9	0.9
Non Energy	-6.1	-1.8	-1.6	2.8	2.5	2.6	2.5	2.4	2.4	2.4	2.3
Inflation (end of period)	1.3	13.4	5.3	7.2	5.6	3.7	2.4	3	2.3	3.1	3.1
Revenue	**28.7**	**34.1**	**32.2**	**29.6**	**30.1**	**29.4**	**29.3**	**28.9**	**28.6**	**28.4**	**12.9**
Energy	14.5	18.4	19	16.6	15.6	15.2	14.8	14.2	13.7	13.3	12.9
Non Energy	14.2	15.7	13.2	13	14.5	14.5	14.2	14.5	14.7	14.9	15.1
Expenditure	**34.2**	**33.9**	**32.4**	**30.7**	**33.6**	**31.1**	**32.6**	**32.8**	**33**	**33.3**	**33.5**
Current	27.9	29	28	26.6	28.9	27.9	28.4	28.5	28.7	29	29.2
Capital	6.3	4.9	4.4	4.1	4.7	3.2	4.3	4.3	4.3	4.3	4.3
Overall Fiscal Balance	**-5.6**	**0.1**	**-0.2**	**-1.1**	**-3.5**	**-1.5**	**-3.7**	**-4.2**	**-4.6**	**-5.1**	**-5.5**
Non-Energy Balance	-20.1	-18.2	-19.2	-17.7	-19.1	-16.6	-18.5	-18.4	-18.3	-18.4	-18.4

The report also identifies the vulnerability of the economy to a drop in global energy demand that reduces oil and gas prices, and specifically a concern that US LNG exports may put downward pressure on global LNG prices.

The latest IMF report[1] identified the vulnerability of the T&T economy to the energy sector, specifically:

"The main external risk over the medium term would be a sustained decline in energy prices (Annex 3). Prices for Trinidad and Tobago's liquefied natural gas (LNG) exports have held up well as it shifts its exports from the United States to Asia, Europe and Latin America[2]. Technological changes along with the development of a significant LNG export capacity from the United States could pose a long-term threat if it significantly expanded global natural gas supplies. However, local producers are confident that demand for natural gas will continue to outstrip supply.

There are significant elements of conservatism in the medium-term projections. Energy price projections already embody market expectations about the impact of the shale revolution. Moreover, staff projections are based on equally weighted (low) U.S. and (high) Asian gas prices, even though Trinidadian natural gas is no longer sold to the United States. Estimated energy reserves, based on past energy audits, appear conservative given the recent pick up in investor interest in the sector.

The discussion in this report regarding the downside risk appears to have been very prescient considering the major drop in crude oil prices that occurred from October 2014 through February 2015.

1 IMF Article IV Staff Consultation September 2014

2 The global energy market for natural gas remains significantly fragmented, with benchmark prices in the U.S. averaging around \$4/MMbtu in 2013, while prices in Japan averaged around \$17/MMbtu in 2013.

Table 2-3 IMF Risk Analysis (Annex III)

(Source IMF Article IV Staff Consultation September 2014)

Nature Source of Main Threat	Likelihood of Realization of Threat	Expected Impact if Threat is Realized	Policies to Ameliorate Threat
Sustained decline in oil or gas prices, triggered by deceleration of global demand and coming on stream of excess capacity.	MEDIUM Over the near-term, the main concern would be a drop in global demand that reduces oil and gas prices. On the supply side, so far the reduction in gas prices has had little impact on the prices received by T&T, which has shifted its exports to markets outside of the United States. However, over the longer term, an increase in LNG production in the United States and elsewhere could eventually serve to better integrate global natural gas markets and weigh on global gas prices. This will be particularly the case if restrictions on U.S. exports of LNG are eased. The T&T economy is heavily dependent on the energy sector, which accounts for roughly half of GDP and central government revenues, and 85 percent of exports, on average.	HIGH The country's vulnerability is increased by current fiscal deficits. On the external side, reserves are ample, but a failure to continue to build wealth, whether in the form of financial or physical capital, will constitute a missed opportunity to convert the country's non-renewable resources into a permanent basis for healthy and diversified long-term growth.	In the short term, the economy is protected by substantial financial cushions: 11.7 months of import cover in external reserves plus the Heritage and Stabilization Fund's net assets, equivalent to 18.5 percent of GDP). Over the medium term, the focus needs to be on diversifying the country's non-energy economic base by public investment and structural reforms. In addition, tax reforms to reduce dependence on energy sector revenues and expenditure reform to contain public consumption will be critical to making public finances more resilient to a downward energy price shock. Were an energy price decline to be rapid, substantial and sustained, fiscal adjustments would likely have to be taken more rapidly, and in an extreme scenario, could be forced to take place in a disorderly fashion.

The last data presently available showing a breakdown of GORTT receipts from the oil & gas sector is for the 2011/2012 financial year:

Table 2-4 GORTT Receipts from the Oil & Gas Sector

(Source: TTEITI)

Government Division	TT $M
Ministry of Finance & Economy - IRD	10,880.3
Ministry of Energy & Energy Affairs	9,080.2
Ministry of Finance & Economy - Investment Division	965.0

Receipts reported by GORTT from the oil & gas sector totalled TT$ 20.925 billion in 2011/2012, with the breakdown between the three GORTT agencies (MOFE-IRD, MEEA and MOFE-Investment Division detailed in Figure 2 4 to Figure 2 6 below.

Figure 2-4 Breakdown of MOFE-IRD Reported Revenues 2011/12 (TT$ 10,880 M)

(Source: TTEITI)

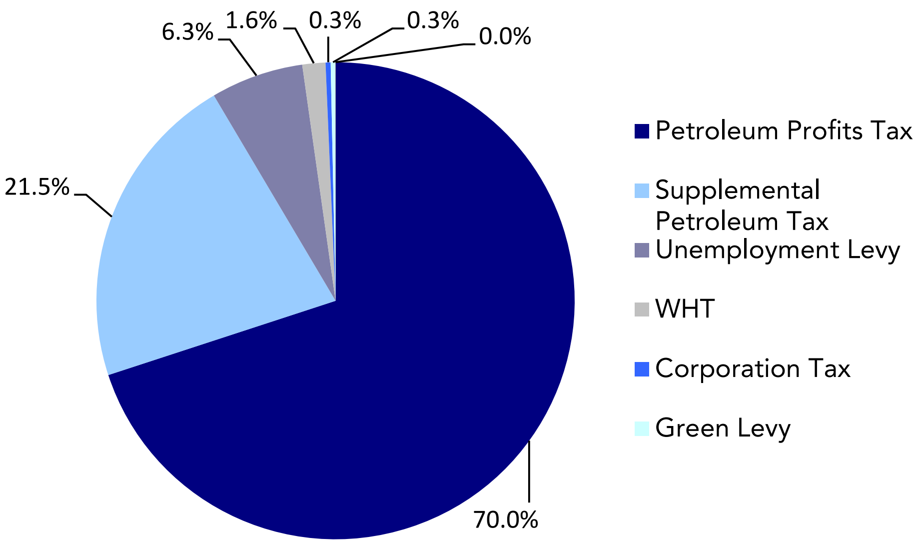


Figure 2-5 Breakdown of MEEA Reported Revenues 2011/12
(Source: TTEITI)

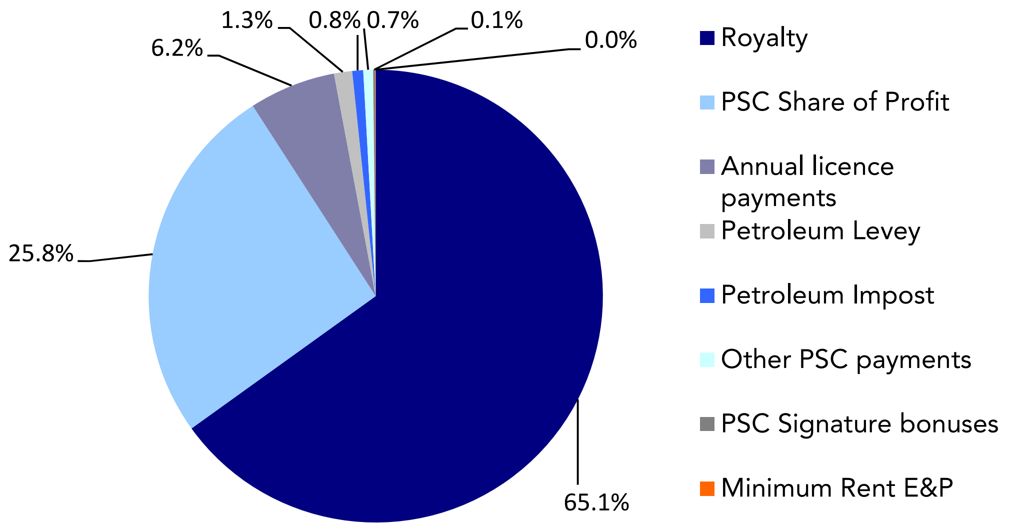
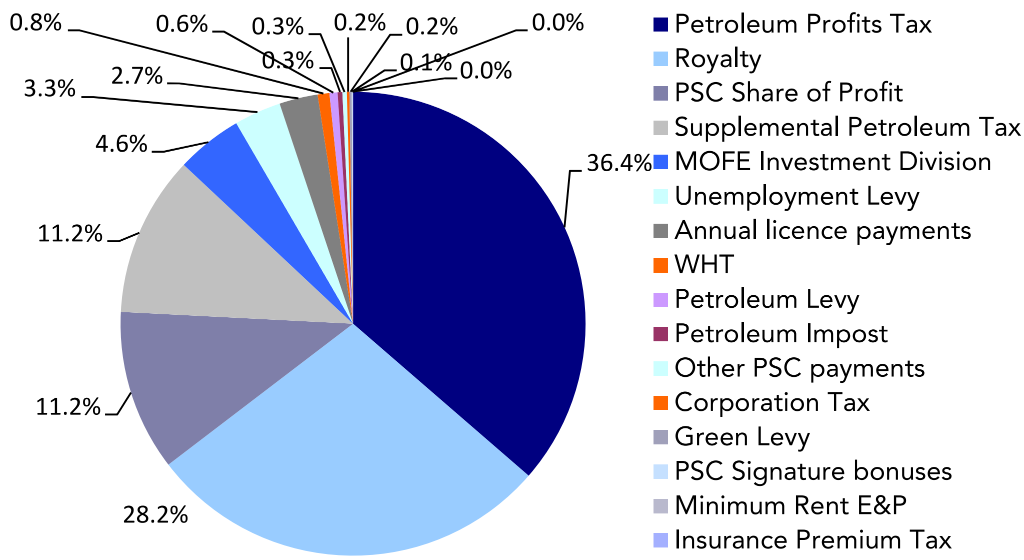


Figure 2-6 Breakdown of all GORTT Oil & Gas Sector Revenues 2011/12
(source: TTEITI)



The largest contribution to GORTT revenue came from the upstream sector through Petroleum Profit taxes, Royalty, PSC profit shares and Supplemental Petroleum Tax which accounted for 87% of all GORTT revenue from the sector.

2.2.2 Labour Contribution

The number of people employed in the energy sector is small relative to other sectors of the economy. In 2013 there were 20,651 person employed directly in the energy sector, ~3.2% of the total workforce.

Table 2-5 Employment in Energy Sector
(Source; CBTT)

Year	Employed in Energy Sector	Total Workforce	Energy Sector employment as % of total Labour force
2010	18,600	618.900	3.3%
2011	18,804	616,395	3.1%
2012	20,146	646,046	3.1%
2013	20,651	650,139	3.2%

The level of employment demonstrates the highly capital intensive nature of the oil and gas industry. Most energy sector workers are employed in service companies rather than operating companies. These companies are predominantly staffed by local workers.

2.3 T&T GAS SECTOR STRUCTURE

2.3.1 The T&T Model

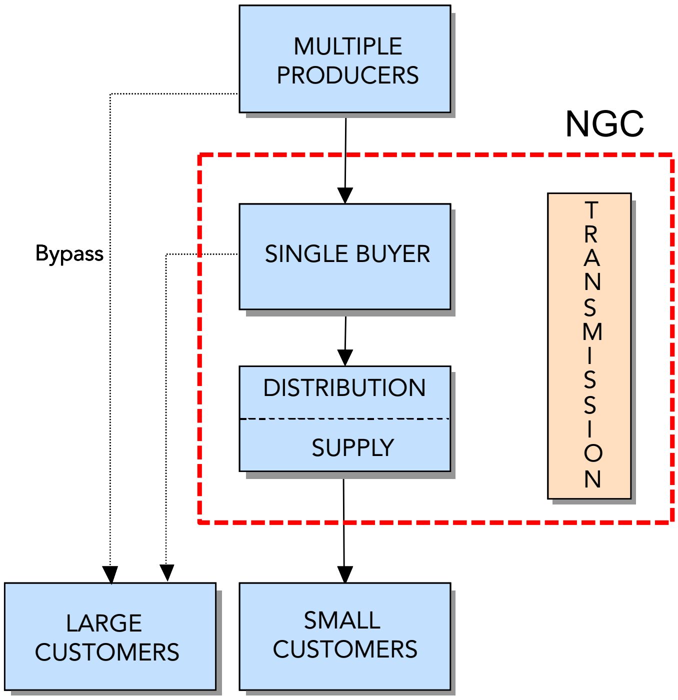
The present structure of the T&T gas sector is a function of its historical development. There has been significant GORTT involvement in establishing the sector both as an investor and facilitator and this remains a feature to the present day. At the present time the T&T natural gas market structure could be characterised as a single buyer structure although it retains many features of a vertically-integrated model (see Appendix J). The key features of the current structure are as follows:

- There is limited competition in the upstream supply of gas with 4 major players and several small producers. Entry is open to all as PSCs are awarded on the basis of competitive bidding, but there is the ability to negotiate directly for out of round contracts. The major producer is bpTT, which holds ~60% of the total gas production and presently holds ~ 55% of the proven reserves.
- In T&T, as in a number of other countries such as the UK, transmission and distribution are undertaken in a single system by a transmission system operator, in this case NGC. NGC also acts as the sole wholesaler of gas, purchasing from suppliers to market to the downstream industries, the power sector and small customers. At the present time there is no trading of gas in the country, NGC purchases gas on term contracts and resells on the same basis. Transportation is provided as a bundled service with gas supply. There is a bypass of NGC as two suppliers, bpTT and BG, supply gas directly to ALNG. This represents ~55% of total gas consumption.
- The downstream sector of the market is sector comprised mostly of large consumers requiring baseload gas supply whose products go for export. The domestic market is very small representing around 10% of total gas consumption into power, cement and small consumers. There is no significant seasonal component to gas demand in the country and little scope for any significant interruptible customers as most large consumers have no ability to switch from natural gas.

There is a significant degree of vertical integration in the sector:

- bpTT is a major player throughout the gas chain. As well as being the dominant upstream player it has downstream interests in the Atlas methanol plant and is a major shareholder in ALNG. It is also a shareholder in Powergen, the largest electricity generator.
- BG, the second largest upstream player is a shareholder in ALNG and a major LNG offtaker through Trains 2, 3 & 4.
- NGC is integrated throughout the chain. It is a supplier of gas, the single buyer and transporter in the midstream sector and has shareholdings in ALNG (Train 1 and Train 4) and Phoenix Park Gas Processors Limited (PPGPL). It is also an offtaker from ALNG through its TTLNG subsidiary.

Figure 2-7 Existing Structure of the T&T Gas Market



This structure has evolved over the last 50 years and has served T&T well in facilitating the development of the sector to a 4 Bcf/d gas economy. However it is appropriate in a Gas Master Plan to question whether this is an appropriate structure for the future, and whether the existing model can be optimised. The expected market background going forward will be quite different from that in which the sector has evolved – specifically the gas in T&T is no longer stranded and has a clear route to market. The market has come into balance, indeed at present is in deficit, and the incremental supply will be of significantly higher cost than in the past. In a gas-short environment difficult decisions will need to be made as to which enterprises gas should be supplied to, or which should not. These decisions are complicated by the fact that NGC is supplying gas on a netback basis where the value fluctuates with international commodity prices.

In setting out a master plan for the gas industry in the country it is important to ask a number of questions:

- What can T&T learn from the global experience of gas sector development?
- Are there any changes that could be made that would make the gas sector run more efficiently/effectively?
- What are the potential costs and benefits of making any changes? Will the benefits outweigh the costs?

2.3.2 GORTT Commercial Participation

GORTT participates commercially in upstream and downstream operations through its national champions the Petroleum Company of Trinidad and Tobago Limited ('Petrotrin'), and NGC. Both companies are wholly-owned by GORTT. Collectively, the taxes and dividends paid by these two enterprises in FY 2013 accounted for approximately $6 billion and were the major contributors to the country's operating surplus. Although Petrotrin pays more in taxes, NGC contributes substantially more revenue when dividends are taken into account. The performance of the two companies is jointly monitored by the Investments Division of MOFE and MEEA.

Petrotrin is typically named as GORTT's nominee for carried interests under a competitive bid round. Unless it is sub-licensing a marine acreage which it holds under an E&P Licence, Petrotrin does not have a regulatory function. When assigning interests to other operators Petrotrin uses so-called "hybrid" arrangements including sub-licences, farm-outs, lease operatorships and incremental production service contracts. Petrotrin also owns and operates the nation's sole petroleum refinery, and is a gas consumer.

NGC was established in 1975 and granted monopoly rights for the purchase, transmission and sale of gas. The company has continued to diversify into upstream production and other commercial activities with current assets valued at over US$ 6 billion. NGC's core business is as a gas merchant, purchasing, transporting, and on-selling natural gas as a fuel for power generation or as a feedstock to customers at the Point Lisas Industrial Estate. The company is the main operator of onshore and submarine pipelines and associated compression and receiving facilities, along with the development of industrial port and site infrastructure. NGC is also involved in the production and marketing of LNG and NGLs. NGC now holds ~82% equity interest in PPGPL, the country's sole cryogenic gas processing facility at Savonetta. Most recently, NGC formed a wholly-owned subsidiary to advance the use of CNG as an alternative transportation fuel. NGC is also involved in upstream production through its acquisition of Total Trinidad's marine assets in the Angostura offshore field.

2.4 GAS SECTOR POLICY IN T&T

2.4.1 Medium-Term Policy Framework

GORTT established a Medium Term Policy Framework (MTPF) for the period 2011-2014 which sets the national priorities of MEEA as follows:

- Increase oil production
- Attract foreign direct investment for new generation downstream plants
- Take T&T's energy sector global
- Arrest the decline of the 2P (proven plus probable) natural gas reserves
- Increase local content in the energy sector
- Create a more competitive environment for the supply of natural gas
- Increase domestic use of natural gas
- Increase use of renewable energy technologies
- Improve energy efficiency
- Modernize the minerals/quarry sector
- Review and reform legislations

2.4.2 Energy Policy

In the GoRTT Freedom of Information Act 2013 Statement the main policy goal was set out as follows:

The main policy goal for the energy sector is to optimally exploit the country's hydrocarbon resources ensuring its efficient administration in order to obtain the greatest returns to the country for the benefit of all citizens.

MEEA issued a draft Green Paper in April 2014 which sets out the objectives for the energy sector and has a number of policy goals related specifically to the gas sector. However the Green Paper is not a GORTT-approved document, and therefore is not quoted in this report.

2.5 THE GAS MASTER PLAN

2.5.1 Rationale

Over the last two decades T&T has developed a substantial downstream gas industry comprising the production of LNG, ammonia, methanol, urea and melamine and the utilisation of gas as a fuel in metal industries and power generation. As a consequence T&T has become a leading exporter of LNG and petrochemicals to foreign markets.

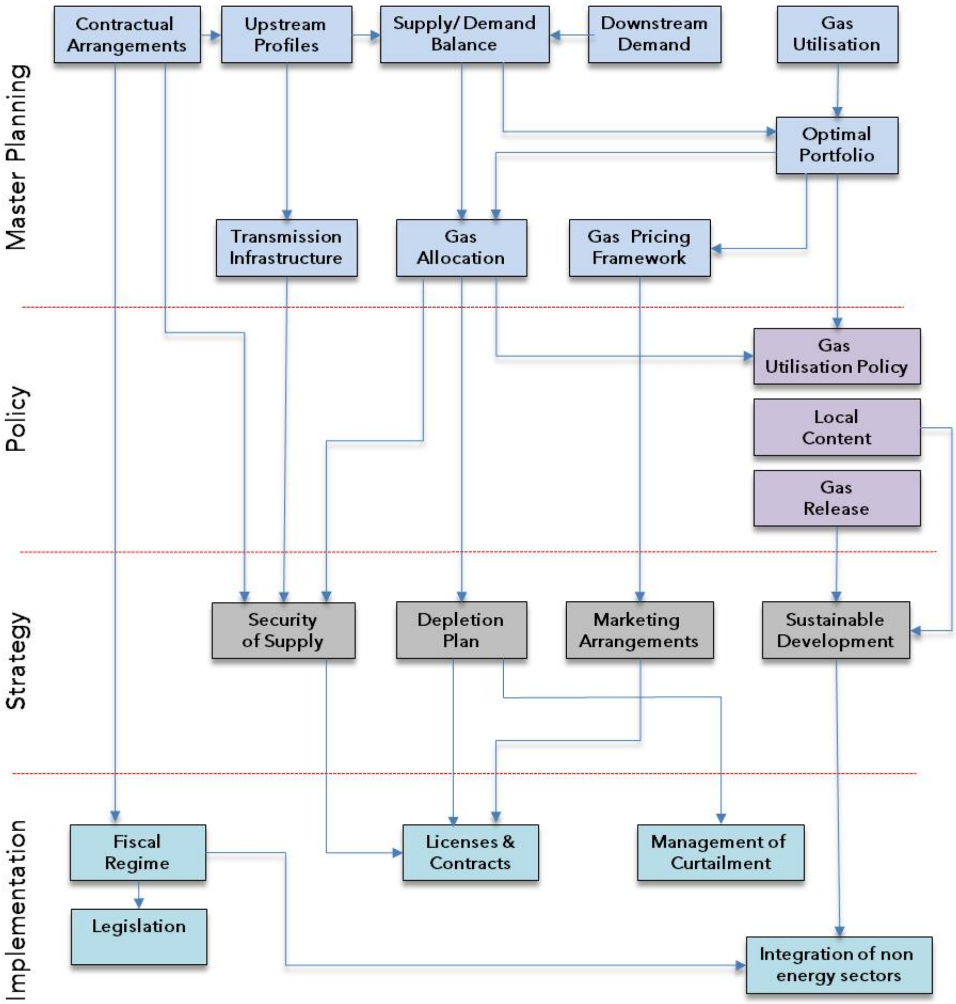
Recent developments in both the local and global gas markets, however, are threatening the viability of the local natural gas subsector. In relation to the gas market, producers have indicated that new contractual arrangements will need to provide for higher gas prices due to higher upstream maintenance and drilling costs.

The recent incidents in the Gulf of Mexico have raised the awareness of companies in respect of safety concerns and have resulted in the escalation of maintenance programmes. Additionally, the new acreage awarded for exploration activity in T&T is in deeper water than existing producing acreage. Consequently, the cost of drilling wells is expected to be higher. This has implications for both the export of LNG and petrochemicals and their derivatives from the country.

Other critical components of the global gas scenario such as the advent of shale gas, coal bed methane have increased the supply of natural gas available on the market. In the US gas production increased from 26.1 trillion cubic feet (Tcf) in 2009 to 31.9 Tcf in 2014, driven by shale gas. Shale is now the largest source of US gas production. As production has increased prices have fallen and US demand for imported LNG has substantially declined. Impacts from the changing global gas environment on T&T are already being experienced and a calculated strategic response is required.

In recognition of the threat posed by these risks and challenges to T&T's model of development of gas-based industries, MEEA decided that an in-depth review into the sector must be conducted. Strategies are required to guide the development of the natural gas sub-sector through 2015 to 2025 in an efficient and effective manner and to address the risks posed to the natural gas sub-sector by local and global developments. The Gas Master Plan will act as a route map for the development of policy and strategy. The various elements of the Master Plan and their linkages are shown in Figure 2-8 overleaf.

Figure 2-8 T&T Gas Master Plan Route Map



2.5.2 Guiding Principles / Objectives

The Master Plan is to act as a blueprint to inform the policies that can be instituted to ensure the domestic gas sector is at the forefront of technological change and is supported by an appropriate institutional and regulatory framework for its efficient and effective management.

Figure 2-9 Role of the Master Plan in Guiding Development

The guiding principles of the Master Plan are to provide a basis for:

- Maximising the value accrued by GORTT from the exploitation of T&T's gas resources, on behalf of the people of T&T.
- This means maximisation of value across the whole sector, i.e. ensuring optimum supply of gas to the existing downstream gas portfolio whilst also seeking to maximise GORTT benefit across the various value chains from the gas resources that are produced.

The key objectives of the study are to:

- Ensure that new exploration effort is undertaken to the maximum extent possible consistent with economic realities of the upstream sector and T&T end markets.
- Ensure all suppliers develop and supply gas their resources to the market in an optimal manner.
- Maximise rent extraction for GORTT from the gas sector subject to ensuring that all players along the chain are sufficiently incentivised to perform optimally for the country.
- Ensure sufficient gas supply to strategic downstream sectors based on national importance (e.g. the power sector and large employers).
- Ensure that if gas supply curtailment is required, it is applied on a transparent, consistent and fair basis.

The full scope of work is included in Appendix A.

3.1 EXPLORATION ACTIVITY

Early offshore exploration efforts began with the first exploration discovery well off the East Coast of Trinidad drilled by Amoco (now bpTT) in 1968 and found over 350 MMbbl of oil in what is now Teak Field. This well was the ninth well drilled in the Columbus Basin by Amoco – the previous eight being dry holes. In the next four years, two other large oil fields were discovered, Samaan (1971) and Poui (1972), as well as two large gas and condensate fields, Cassia and Immortelle. This initial success was followed by a twenty year period with limited exploration finds, and at this time there was no market in T&T to monetise gas discoveries. However, by 1993 opportunities for increased usage of gas by the domestic gas market and in the export of LNG were being developed which spurred interest in gas and a revival in exploration.

Table 3-1 Selected T&T Gas Discoveries

(Source; bpTT, BGTT, RyderScott, MEAA)

Field	Operator	Area	Year Discovered	Year of First Production
Cassia	bpTT	ECMA	1969	1983
Dolphin	bpTT	ECMA	1976	1995
Hibiscus	BG	NCMA	1981	2002
Chaconia	BG	NCMA	1981	2003
Flambouyant	bpTT	NCMA	1987	1993
Mahogany	bpTT	ECMA	1994	1998
Amherstia	bpTT	ECMA	1995	2000
Juniper	bpTT	ECMA	1996	Undeveloped
Starfish	BG	ECMA	1998	2014
Parang	bpTT	ECMA	1998	Undeveloped
Osprey	EOG	U(a) Block	1998	2002
Dolphin Deep	bpTT	ECMA	1998	2006
Mango	bpTT	Mango	1971/2000	2007
Manakin	bpTT	ECMA	2000	Undeveloped

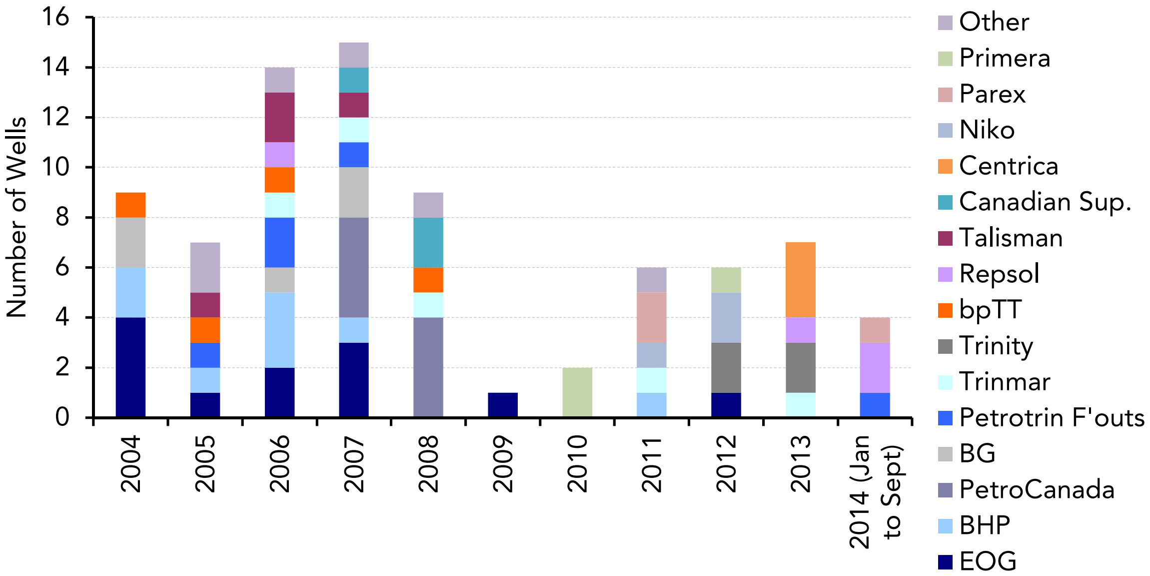
In the period from 1994 through 1998 the application of new technology and new play concepts resulted in the discovery of over 14 Tcf of gas and 300 million barrels of oil and condensate (>2.5 BBOE). During this time 21 wells were drilled with 15 being commercial discoveries for over a 70% success rate. These exceptional results over this short time period caused a dramatic resurgence of interest by the industry in the exploration potential in the Columbus Basin.

The change in the success rate from 14% in the 1989-1993 time period to 71% in the 1994-1998 was in large part due to the introduction of new technology used for prospect development. For prospects in the Columbus Basin trap definition and fault seal are the highest risk factors. Prior to 1994, the use of 3D seismic data in Trinidad was limited to development drilling and all exploration wells were drilled based on 2D seismic data only. Since 1994 all Trinidad exploration wells have been drilled using 3D seismic data. The 3D seismic significantly helps to reduce risk for trap definition by better imaging the complex faulted structures in the Columbus Basin.

Exploration activity over the last decade is shown in the figure below. The relatively robust activity level (in terms of exploration wells drilled) dropped abruptly in 2009, and has resumed at a lower level from 2011 onwards. The exploration activity is, unsurprisingly, strongly correlated with the success of the various bid rounds and upstream blocks taken up as a result of the licensing rounds. For 2010/11 bidding rounds the PSC terms on offer from MEEA were improved and this appears to have led to more interest, awarded blocks and subsequent exploration activity.

Figure 3-1 Exploration Drilling since 2004

(source: MEEA)



That said exploration drilling is still some way below the highs seen in 2006 and 2007 when 14 and 16 wells were drilled respectively.

3.2 ACREAGE AWARD

The offshore areas of T&T comprise 42,500 km^2 of which approximately half of the shallow water and one quarter of the deepwater acreage is currently leased to independent operators. Approximately 70% of the offshore contract area is continental shelf where water depths are 200 m or less. The remaining area contains the deeper water blocks where the water becomes progressively deeper towards the east, reaching over 1,000 m in some areas.

T&T has a well-established licensing framework which has evolved over time from royalty type arrangements to Production Sharing Contracts (PSCs). The exploration and production licence blocks are shown in the figure overleaf.

Exploration and Production Licences operate under a royalty structure. Twenty-two licences were awarded between 1994 and 2009. The rate of royalty was set at 12.5% on most licences except for a small number granted a royalty of 10% flat or 10% escalating to 15% as production increases.

Thirty-nine Production Sharing Contracts (PSCs) have been awarded primarily between 1996 and 2013, although Block 6 PSC was awarded in 1974 and Block E in 1993. The terms of the PSCs have been adjusted over the years in response to oil and gas market conditions and the level of interest in acreage from international E&P companies. The latest bid round in 2013 allowed contractors to bid on the duration and work programme for three exploration phases and the profit production split with the government, specified as a function of oil and gas pricing and production rate.

As is discussed in Section 2, bpTT, BG, EOG and BHP are the current major gas producers in T&T. Repsol, Centrica, Niko, Trinmar, NGC and Petrotrin also hold shallow water acreage at various stages of development. Licensed deepwater acreage is held by BHP, BP, BG and Repsol.

T&T has launched regular competitive bidding rounds for acreage over the last few years, with the emphasis for most recent rounds being on deepwater blocks. The recent history of the licensing rounds is shown in the table below:

Table 3-2 Recent T&T Acreage Bidding Rounds

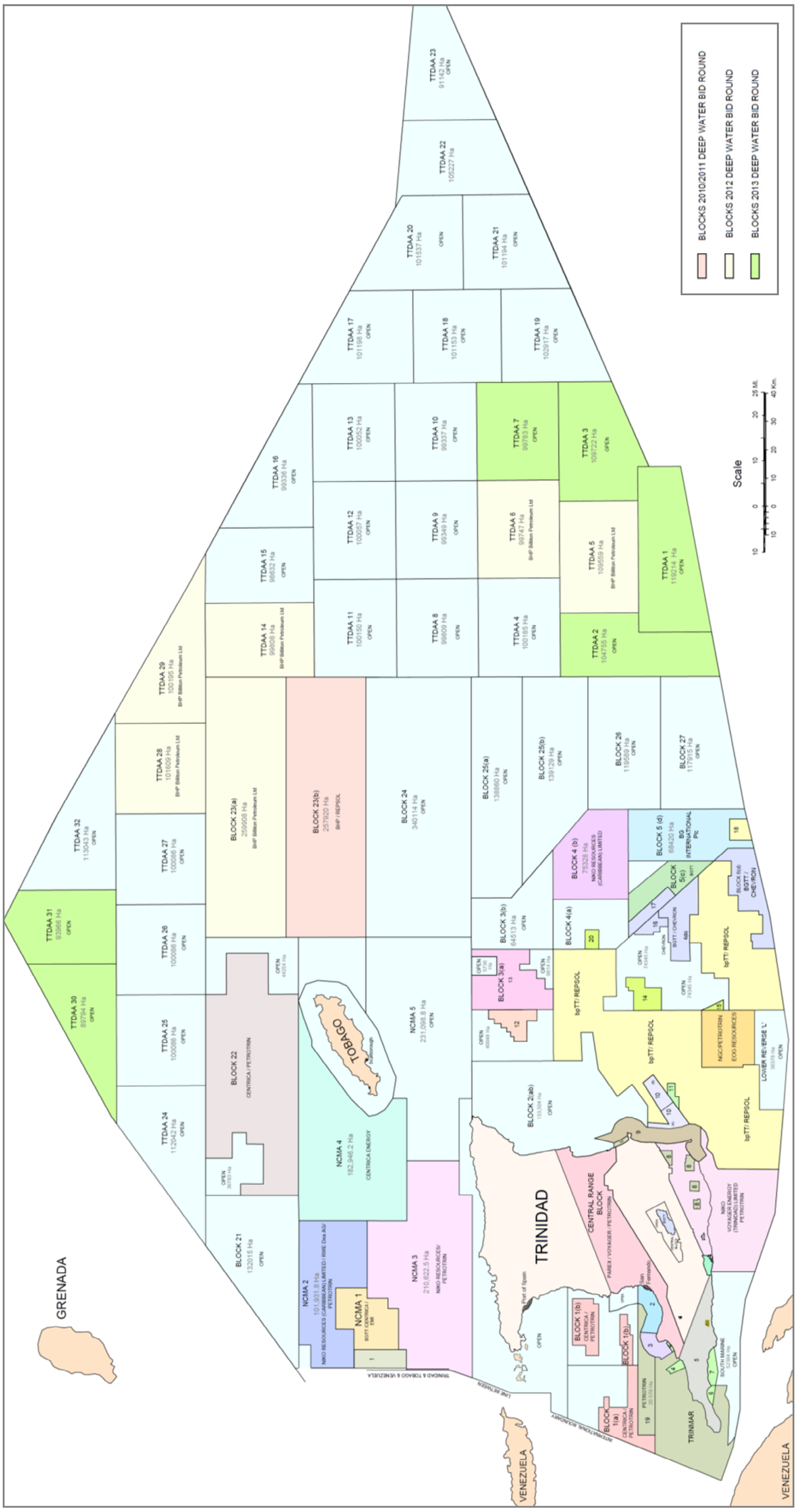
(source: MEEA)

Bid Round	Launch Date	Blocks on Offer	Blocks awarded
2010 Shallow Water (<1000 m)	April 2010	ECMA 4b, 5d NCMA 2,3,4,5, North Marine Gulf of Paria	NCMA 4 Centrica ECMA 4b, NCMA 3 Voyager(now Niko) NCMA 2 Voyager(now Niko), RWE
2010 Deepwater	September 2010	TTDAA 1,2,3,5,6,7,13,14 Blocks 23a,23b, 24	(5 bids on 3 blocks) 23a, TTDAA14 bpTT Block 23b to BHP
2011 Deepwater	November 2011 (from April 2011)	TTDAA 1,5,6,28,29 Block 25a	(12 bids on 5 blocks) TTDA 5,.6,28,29 BHPBilliton
2013 Deepwater	August 2013	TTDAA 1,2,3,7,30,31	(3 bids on 5 blocks) TTDA 3 & 7 to BHPBilliton and BGTT

Since 2009 all new acreage awards have been made under competitive bidding rounds where contractors submit PSC terms to MEEA for its consideration, and selection is determined by the most attractive offers. The 2010 competitive bidding round was the first to allocate new acreage for exploration and production since 2005. This reflects a combination of factors: no blocks were awarded for the 2006 round for ultra-deepwater and there were no further blocks offered for bidding thereafter, in part due to the onset of global economic crisis and the collapse in energy prices in mid-2008.

Figure 3-2 T&T Exploration & Production Block Map 2014

(source: MEEA)



3.3 EXPLORATION AND DEVELOPMENT TECHNOLOGY

The upstream oil & gas industry has become more technology-intensive over the years. The world's remaining unexploited hydrocarbons are to be found in increasingly more difficult locations or challenging geological formations. The migration to deeper water offshore prospects (deep water being considered to be depths greater than 1000 m) is probably the most significant current trend in this regard. Technical innovation has been paramount in the finding, assessing and economic exploitation of these resources.

Deepwater technology can reduce the finding and development costs associated with a large gas resource base, allowing a greater proportion of the reserves to be developed economically. Deepwater technology is best seen as a continuously accumulating extension of techniques which have allowed the oil and gas industry to move into extensive offshore environments since the 1960s. The early years led to the development of marine seismic methods, floating drilling systems, and fixed marine production structures. Later years drove developments in 3D and 4D seismic, dynamically positioned drilling systems, measurement while drilling, and remotely operated vehicles. As the push into ever deeper waters grew, the industry continued to respond with a novel array of development concepts, such as tension leg platforms, spars, and subsea production systems, which hybridised the positioning of engineering systems above and below the water line in what amount to truly modern engineering developments.

In particular, technology has a crucial role in providing the information with which to make better deepwater exploration decisions. Given the complexity and high cost of drilling in deep water, there is great value in being able to identify the best locations to drill exploration wells. This skill hinges on generating an accurate and comprehensive picture of the earth's subsurface. The use of wide-azimuth, ocean-bottom seismic surveying has enabled better imaging of deepwater reservoirs. Conventional 3D data acquisition processes are being rapidly replaced by new broad bandwidth technology which enables seismic data to be recorded across a much wider spectrum of frequencies, from low frequency waves for deeper penetration of the subsurface to high frequencies generating higher resolution images.

Subsea technology has evolved rapidly, allowing equipment to be placed closer to the wells to improve hydrocarbon recovery. Reservoir pressure in producing fields falls over time, causing production output to decline. For production to continue and to maximise recovery from the fields, hydrocarbons must be produced at lower pressures or production will cease. The use of subsea gas compression to reduce wellhead pressure avoids the installation of a gas compression platform and reduces overall capital and operating costs, and is now becoming a reality. Costs are not only important for mature fields, but for those currently in development. A full subsea field development can be much less costly than a platform-based development scheme. This, coupled with higher recovery rates, higher energy efficiency, lower maintenance and increased reliability, supports the use of subsea systems in many offshore and deepwater developments. However, like all development approaches, subsea infrastructure has characteristics which favour some applications and place it at a disadvantage in others. Industry experience to date shows that subsea tiebacks are only attractive over moderate tieback lengths (<120km) and for certain produced fluids and reservoir characteristics. Much of T&T's deepwater frontier lies well beyond industry capability for subsea tie backs to existing shallow water fixed platforms, requiring consideration of deepwater floating structures to develop the full potential of this acreage.

It is worth noting that the way in which innovation has taken place in the industry has changed over the years. Technology development was once the domain of the IOCs with large R&D departments. Presently more research and development is undertaken by service companies as evidenced by the fact that service companies tend to file considerably more patents per innovation than other types of organisation. However, it is noted that despite the increasing degree of globalisation in the E&P marketplace, the USA still plays an extremely dominant role in the industry's overall R&D and technology deployment activities.

An in-depth discussion of new developments in upstream exploration is provided in Appendix B. It should be noted that this discussion assumes and focuses on non-associated gas field developments. It is expected that oil field developments with associated gas will have a decision framework distinctly different from the objectives of a Master Planning strategic initiative focused on maintaining supply of gas to T&T's existing onshore gas market. At present there are no deepwater oil field discoveries in T&T. However, in the event that liquid hydrocarbons or a very rich gas reservoir is discovered in the deep or ultra-deep waters, then it is likely that commercial development will require the installation of floating platforms. Therefore, investigations and discussions covering new deepwater technologies consider both oil and gas reservoirs, as well as the range of natural gas liquids and condensates that may eliminate the simplest tieback options from consideration.

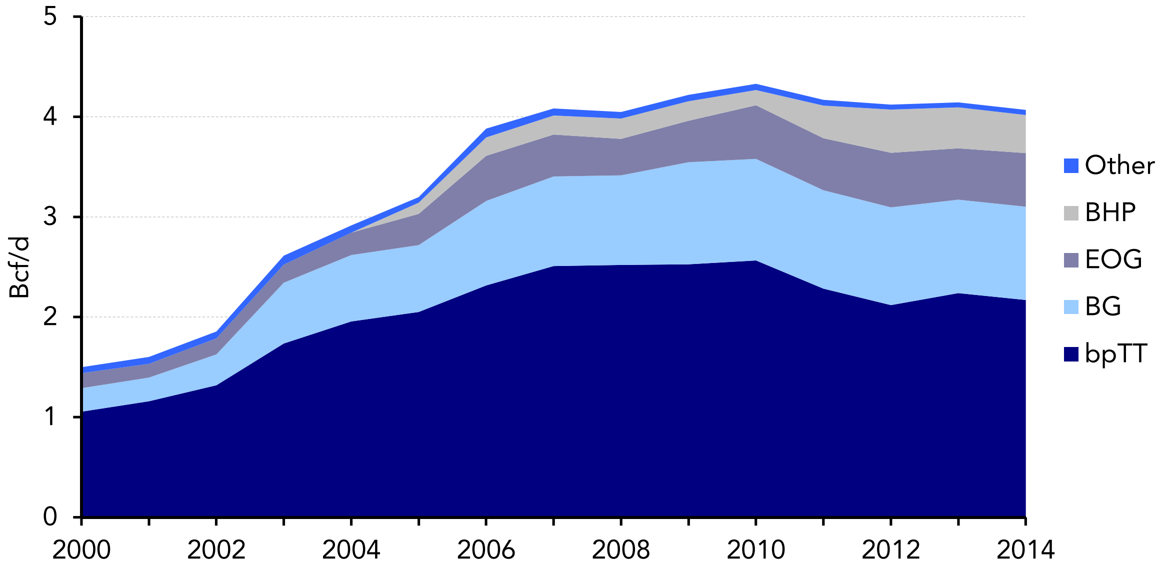
3.4 HISTORICAL PRODUCTION

Gas production in T&T is from two primary producing areas, the Columbus basin to the South East of Trinidad and the Tobago Basin which runs from east to west to the north of Trinidad. Infrastructure development in these areas is illustrated in Figure 3-4 and Figure 3-5. The Columbus Basin is one of the larger gas provinces in the western hemisphere to be developed over the last few decades. Major gas fields include Immortelle, Cassia, Mahogany, Flamboyant, Amherstia, Corallita, and Kapok together totalling over 15 Tcf of recoverable reserves. The most recent Mango discovery adds another 3 Tcf. The Tobago Basin contains the Hibiscus, Poinsettia and Chalconia fields. These fields were discovered in the early 1980's but it was not until the 1990s that they were further developed to supply the ALNG project. These fields are grouped in the North Coast Marine Area (NCMA).

In 2014 T&T gas production was an average of 4.07 Bcf/d, with bpTT, BGTT, EOG accounting for nearly 90% of gas production in the country. bpTT is the largest gas producer in T&T, with 10 gas fields in production, mostly in the East Coast Marine Area (ECMA), and in 2014 produced an average of 2.17 Bcf/d, which accounted for 53% of the total production. BG produced an average of 0.93 Bcf/d (23% of the total) from seven fields in the ECMA, NCMA, and Central Block. EOG produced 13% of the gas produced in T&T.

Figure 3-3 Historical Gas Production 2000-2013

(source: MEEA)



bpTT's production is sourced from the Columbus Basin and has built up through development of a succession of fields over the last 12 years. Most recently bpTT has sanctioned development of the Juniper field, due onstream in 2017. bpTT also holds significant gas resources straddling the border with Venezuela which are as yet undeveloped.

Figure 3-4 Columbus Basin Development
(source: Petroleum Economist)

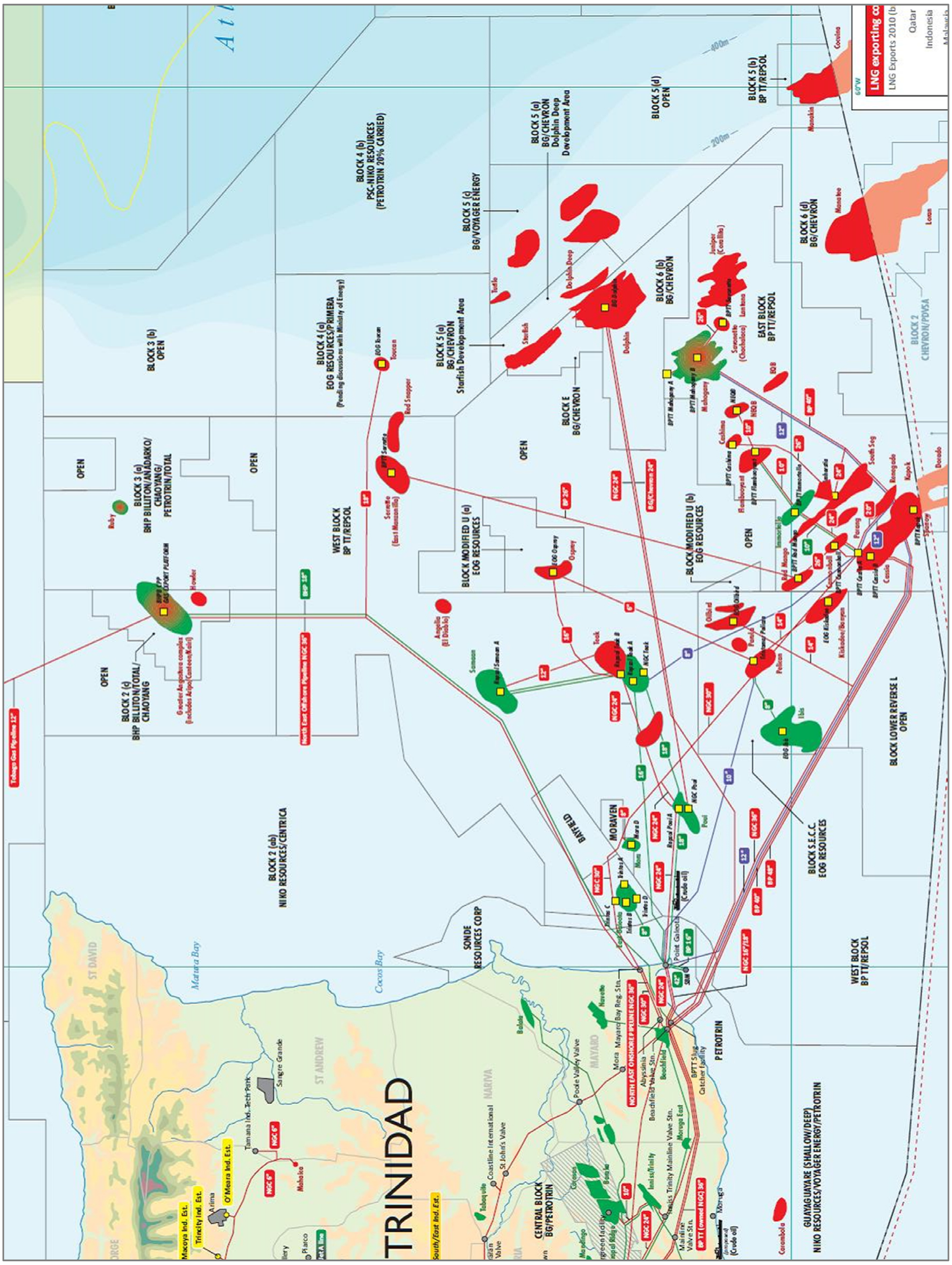
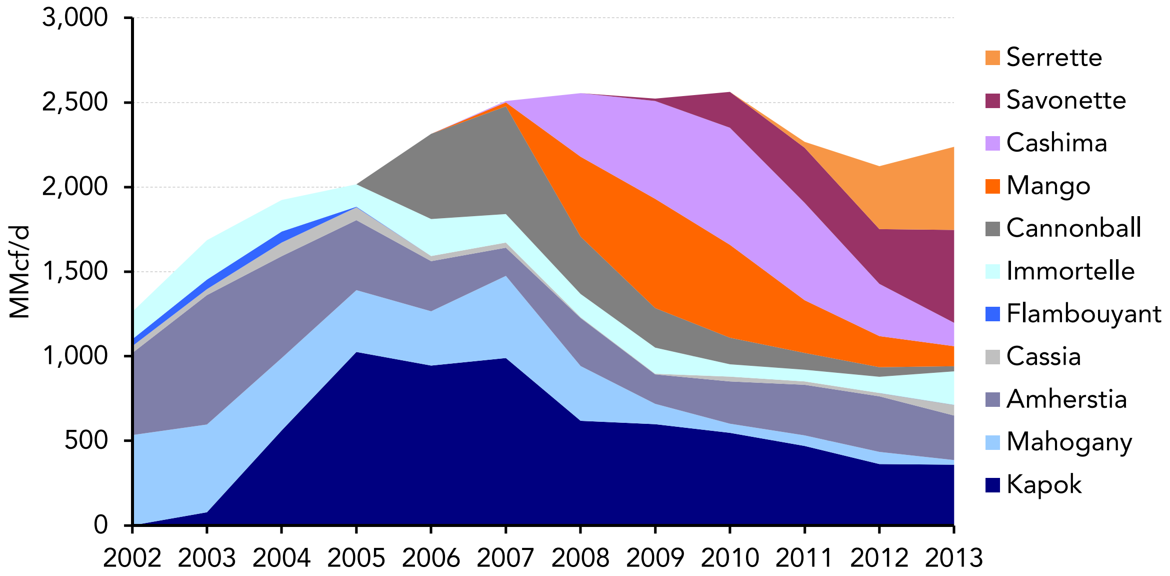


Figure 3-5 Tobago Basin Development

(source: Petroleum Economist)

Figure 3-6 bpTT Production History
(source: MEEA)



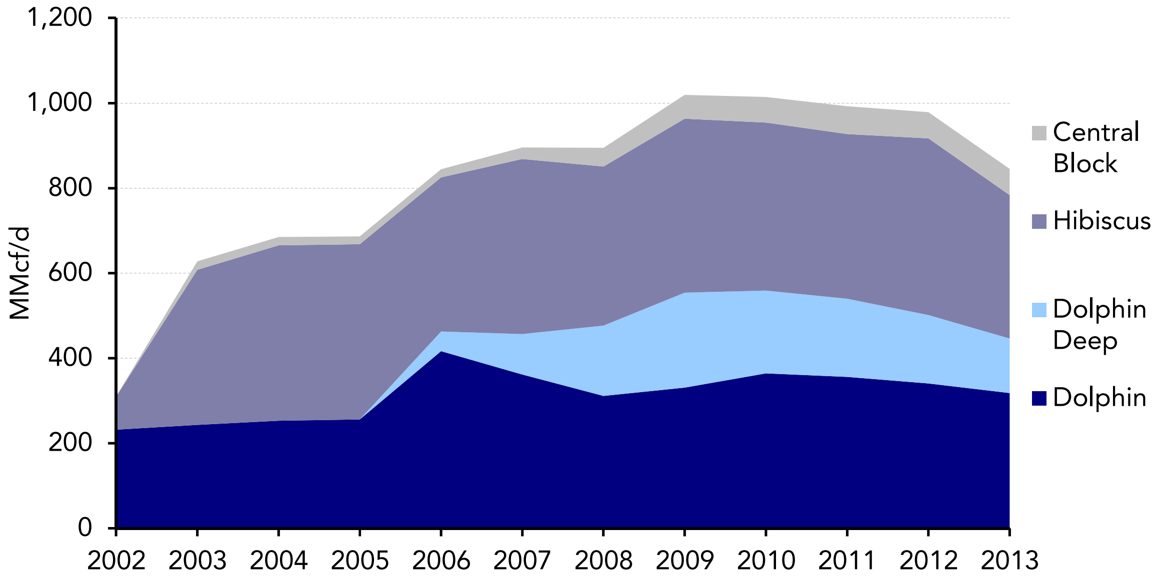
Major fields operated by bpTT are as follows:

- Cassia Field - located 55 km off the southeast coast of Trinidad in the Columbus Basin. The discovery well for the Cassia Field was drilled in 1973. At that time the field was considered a gas condensate field and further exploration was halted until gas market forecasts improved. Towards the end of the decade further development work was undertaken and the Cassia platform was installed in around 60 m of water in 1982 and had the capacity to produce 450 MMcf/d, evacuated through a 30” pipeline to the Beachfield receiving station.
- Mahogany Field - discovered in 1968 approximately 95 km off the southeast coast of Trinidad. Further drilling established a large gas field but at that time there were no gas markets in T&T and the field was not developed. The development of ALNG spurred a revival of interest and the field was proved up in the mid-1990s with 2.6 Tcf of reserves that were dedicated to ALNG. The Mahogany Hub comprises the Mahogany Alpha (A) and Bravo (B) platforms. Over the next 3 years, it is expected that production from the Savonette field, the existing Mahogony production and from the Juniper subsea manifold tie-in will all flow through the Mahogany hub raising its capacity from the existing 650 MMcf/d to 1 Bcf/d.
- Savonette Field - situated around 80 km offshore Trinidad, at a water depth of approximately 290 ft. Owned and operated by bpTT, it was discovered in 2004. Natural gas production started in late October 2009. The project is situated over the Chachalaca exploration discovery. The unmanned platform has a production capacity of 1 Bcf/d. The gas is processed at the Mahogany B platform, which is supplied from the Savonette platform by an 8.5 km-long subsea pipeline.
- Kapok Field - in July 2003, bpTT started production at its Kapok field from an unmanned satellite platform connecting to the company's central processing hub at Cassia B. Peak production from the field is expected to reach 1 Bcf/d. Because Cassia B has a nameplate natural gas processing capacity of 1.6 Bcf/d of natural gas and 50,000 bbl/d of liquids, it is likely that bpTT will continue to develop natural gas resources in surrounding fields.

- Mango Field – The field is located on Galeota block about 35 miles southeast of Galeota Point in 235 ft of water off Trinidad. The Mango field was discovered in 1971 and after further appraised in 2000 has been developed using a single unmanned platform with a capacity to produce from nine wells. Production began in 2007. The field adds an incremental 750 MMcf/d of gas deliverability plus some associated condensate. Gas is transported through a 6 km, 26-in. subsea pipeline tied into the current Cannonball pipeline and the Cassia B gas processing hub. The Mango platform was the second to be built to the same standardised design as the Cannonball platform, which was the first offshore platform to be designed in T&T. The Cannonball platform was installed in 2005.
- Juniper Natural Gas Project - The Juniper project was sanctioned for development in 2014 and will feature the construction of an unmanned platform together with corresponding subsea infrastructure, a first for bpTT. The Juniper facility will take gas from the Corallita and Lantana fields located 50 miles off the south east coast of Trinidad in water depth of approximately 360 feet. The development will include five subsea wells and will have a production capacity of approximately 590 MMcf/d. Gas from Juniper will flow to the Mahogany B hub via a new 10 km flowline. Drilling is due to commence in 2015 and first gas from the facility is expected in 2017.

BGTT's production is split between the Dolphin East Cost Marine Area (ECMA) in the eastern Columbus Basin and the Hibiscus North Cost Marine Area (NCMA) complex to the north west of Trinidad. Both of these fields have long and relatively stable production histories, but will gradually decline in the coming years. BGTT also holds significant gas resources straddling the border with Venezuela which are as yet undeveloped.

Figure 3-7 BGTT Production History
(source: MEAA)



Major fields operated by BG are in ECMA and NCMA:

- ECMA - the Dolphin gas field began production in March 1996. The field is in Block 6b, 80 km off the east coast of Trinidad in ECMA and is operated by BG with a 50% equity interest (Chevron holds the remaining 50%). The project has four subsea wells and a 10 km subsea tieback to the Dolphin platform. Produced natural gas from the Dolphin platform is transported via a 24-inch, 97 km pipeline to the onshore Beachfield gas processing facility. The adjacent Dolphin Deep field was discovered in 1998, and first gas was delivered in July 2006, to ALNG Trains 3 and 4. Design plateau production from the field will average 220 MMcf/d of gas. The Dolphin Deep development consists of two wells with subsea completions tied back to the Dolphin platform. The Starfish field which started up in December 2014 is located around 50 miles offshore, the field is connected to the 3,000 ton Dolphin platform. The Starfish project was sanctioned in 2012 and has involved ongoing collaboration with local and international contractors.

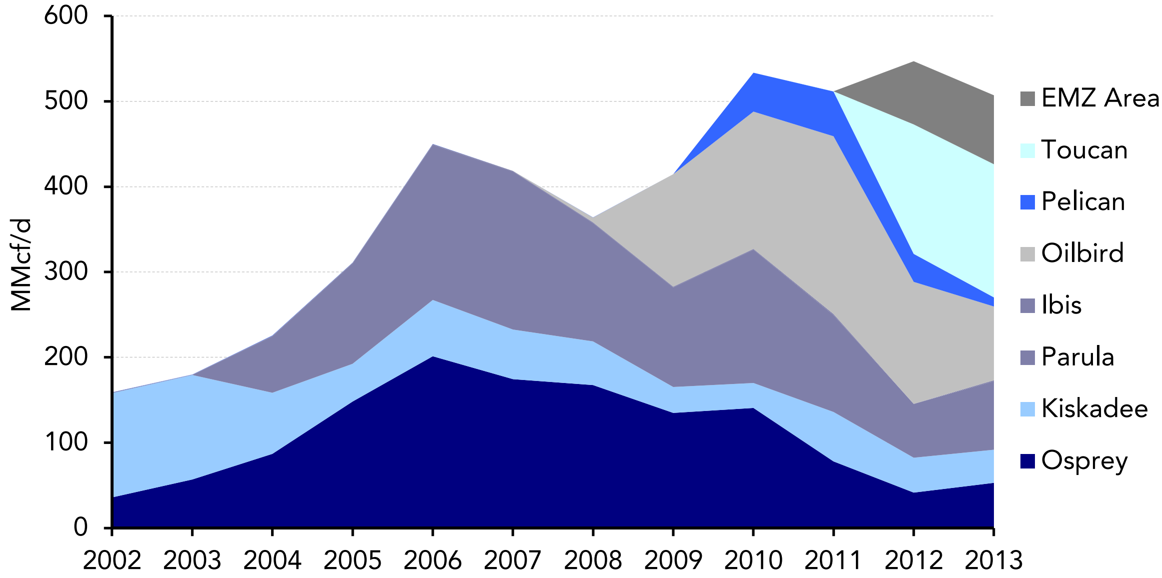
- NCMA – situated 40 km off the north coast of Trinidad in roughly 150 m of water and consists of six gas fields: Hibiscus, Poinsettia, Chaconia, Ixora, Heliconia and Bougainvillea. In April 2000, a Unitization Agreement was formed and signed to develop NCMA[1] and in December 2000 GORTT gave approval for the development of the first three fields, Hibiscus, Poinsettia and Chaconia. All six fields supply gas to ALNG Trains 2, 3 and 4. The Hibiscus and Chaconia fields commenced production in 2002 at roughly 400 MMcf/d. There is a 107 km, 24-inch-diameter pipeline from the Hibiscus platform to ALNG. The Poinsettia, Bougainvillea and Heliconia fields were developed as a third phase of the development, with a production platform on Poinsettia and upgrading the Hibiscus facility to accommodate production from the newly developed fields. The Poinsettia field, situated in 530 feet (162 meters) of water, is developed through 4 platform and one subsea well. The Poinsettia platform, capable of producing 350 MMcf/d, gathers production from the Poinsettia, Bougainvillea and Heliconia fields for export via a 20-inch-diameter pipeline to the Hibiscus platform, which is then transported to shore. Poinsettia commenced production on January 2009.

EOG's production is sourced from the Columbus Basin and has built up through development of a succession of fields over the last 12 years.

[1] BG serves as the operator of the project and holds a 45.88% interest; Petrotin holds 19.50% interest; Eni holds 17.31% interest; and PetroCanada holds the remaining 17.31% interest.

Figure 3-8 EOG Production History

(source: MEAA)



BHP's production is sourced entirely from the Angostura field in the Columbus Basin.

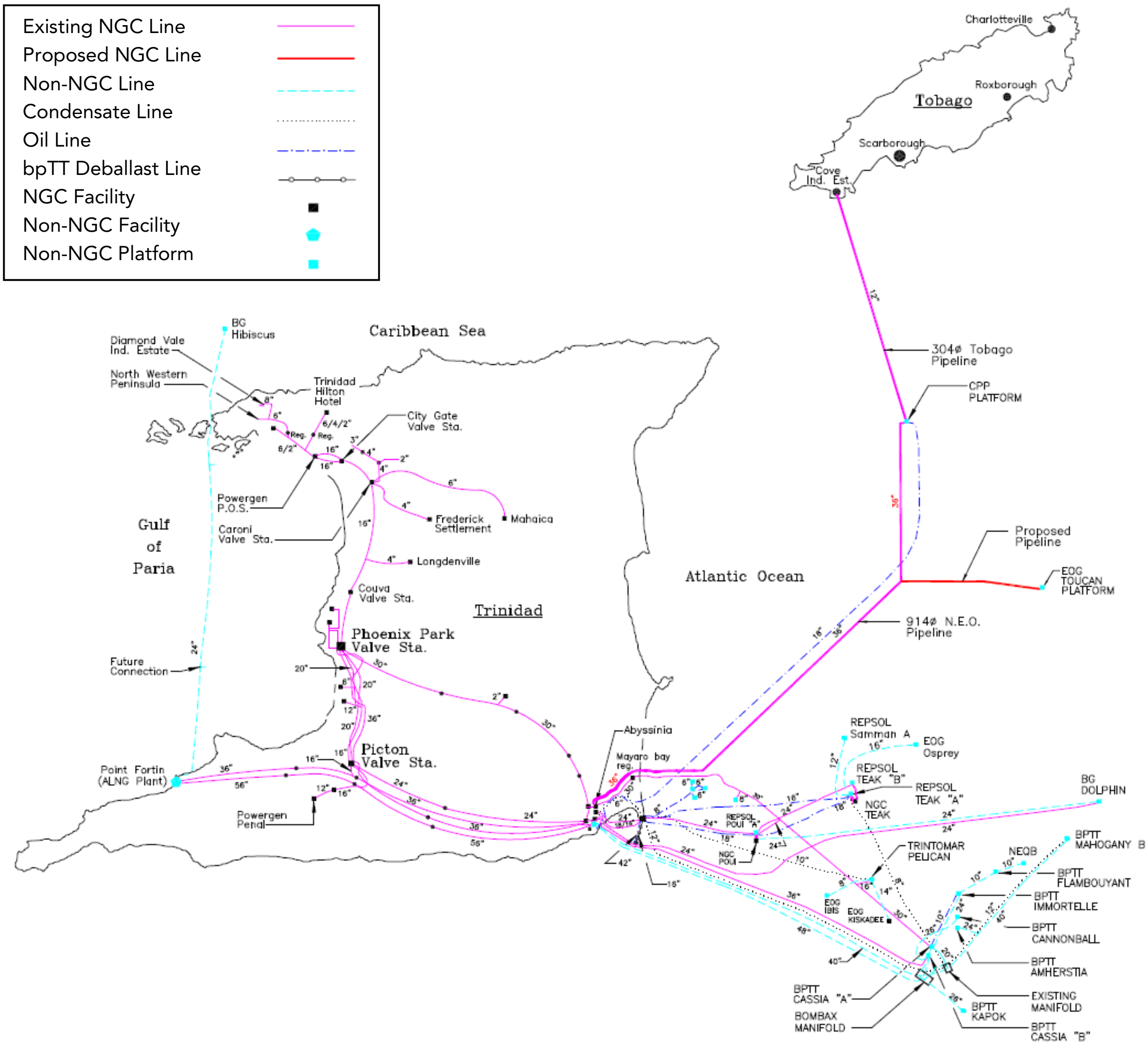
Analysis of the global E&P position of the key T&T upstream players is included in Appendix C.

4.1 GAS TRANSPORTATION INFRASTRUCTURE SYSTEM

An integrated network of offshore and onshore pipelines and processing facilities has been developed in T&T to ensure that gas can be transported effectively to the consumers. The gas transmission infrastructure installed in T&T is illustrated in the figure below:

Figure 4-1 T&T Gas Transmission Infrastructure

(source: NGC Data)



The gas pipeline system in Trinidad has evolved since the 1970's to be a major transmission and distribution system which consists of 6 major offshore pipelines 24", 30", 36", 56", 24" supplying Trinidad and a 12" to Tobago. A more detailed schematic of the gas pipeline system is provided in

Appendix L. A network of onshore pipelines carry gas via Beachfield to major customers at ALNG and Phoenix Park.

Table 4-1 Major Onshore Gas Pipelines

(Source: MEAA)

Operator	From	To	Built (Year)	Size (")	MOP (psi)	MAOP (psi)	Capacity (MMcf/d)	Length (km)
NGC	Point Galeota	Beachfield		24	1000	2160	400	26
NGC	Mayaro Bay Regulator Station	Abyssinia Accumulator Station	2011	36	1150	1440	1250	10.02
NGC	Columbus Point, Tobago	Cove Estate, Tobago	2012	12	1150	1440	119	0.8
NGC	Guayaguayare Bay	Beachfield	1978	24				
NGC	Mayaro Bay Regulator Station	Phoenix Park	1982	30				
NGC	Beachfield	Phoenix Park	1999	36				
NGC	Beachfield	ALNG	2005	56				
NGC	Beachfield	ALNG	1998	36				
BPTT	Rustville	Beachfield	2002	48				
NGC	Mayaro Bay Regulator Station	Abyssinia	2008	36				
NGC	Point Galeota	Beachfield	n/a	24	1,000		400	26
NGC	Mayaro Bay Regulator Station	Abyssinia Accumulator Station	2011	36	1,150	1,440	1,250	10
NGC	Columbus Point, Tobago	Cove Estate, Tobago	2012	12	1,150	1,440	119	0.8
NGC	Guayaguayare Bay	Beachfield	1978	24				
NGC	Mayaro Bay Regulator Station	Phoenix Park	1982	30				
NGC	Beachfield	Phoenix Park	1999	36				
NGC	Beachfield	ALNG	2005	56				
NGC	Beachfield	ALNG	1998	36				
BPTT	Rustville	Beachfield	2002	48				
BGTT	Rustville	Beachfield		24	1,694	1,480	420	
NGC	Mayaro Bay Regulator Station	Abyssinia	2008	36				

The transmission system operates at three pressure regimes:

- Upstream pressure of 900 - 950 psig (62-65 barg)

- Midstream pressure of 790 – 800 psig (~55barg)
- Downstream pressure of 580 psig (~40barg)

Table 4-2 Major Offshore Gas Pipelines

(Source: MEAA)

Operator	From	To	Built (Year)	Size (")	MOP (psi)	MAOP (psi)	Capacity (MMcf/d)	Length (km)
ATOC	Mahogany 'B'	Rustville	1998	40	1250	1440	1275	98.2
BPTT	Cassia B Platform	Rustville	2002	48	1070	1480	1810	62.8
BPTT	Immortelle Platform	Cassia A Platform		24				
BPTT	Kapok Platform	BOMBAX Subsea Manifold		26				
BPTT	Cassia A Platform	BOMBAX Subsea Manifold		20				
BGTT	Poinsettia Platform	Hibiscus Platform	2009	24		1,480		
BGTT	BG's Dolphin Platform "A"	NGC's Poui Compression Platform	1995	24	1,694	1,863 – 2,191	325	64
BGTT	Hibiscus Platform	Clifton Hill beach, Point Fortin	2001	24	1,200	1,950	400	107
EOGRTL	Osprey Platform	tie-in point on NGC 24'' line (BPTT acreage)	2001	16	1,250	1,440		
EOGRTL	Toucan Platform	tie-in point on North East Offshore Pipeline			2,220	2,220		26
NGC	BHPB Platform (Angostura Field)	Mayaro Bay Regulator Station	2011	36	1,150	1,440	1,250	84
NGC	Teak "B" & Poui "A" Platforms	Point Galeota		24	1,000	2,160	400	135
NGC	Cassia B platform	Mayaro Bay Regulator Station		36				
NGC	BHPB Platform	Columbus Point, Tobago	2012	12	1,440	1,440	119	54
NGC	BP Cassia A Platform -	PLEM Mayaro		30				
NGC	Cassia Platform	Mayro Regulator Station	1982	30				
BPTT	Rustville	Beachfield	1998	40				

The major transmission infrastructure is shown in Table 4-1 and Table 4-2, the main features of which are:

- Transmission capacity from BP's fields in the Cassia region in the SE of the developed shallow water area includes 40" and 48" lines owned by BP and 30" and 36" lines owned by NGC with a combined capacity in excess of 4.5 Bcf/d, more than adequate for current production levels of 2.2 Bcf/d
- BG's ECMA Dolphin complex exports through an NGC 24" line and BGTT 24" line with a combined capacity of circa 0.77 Bcf/d, which is more than adequate for current production levels of 0.45 Bcf/d
- BG's NCMA Hibiscus complex exports through a BGTT 24" line with a capacity of 0.4 Bcf/d, which is currently running at design capacity.
- BHP's Angostura Field to the east of Trinidad exports gas to Trinidad through a 36" NGC pipeline with a capacity of 1.25 Bcf/d and to Tobago through an NGC 12" pipeline with a capacity of 0.12 Bcf/d, the combined capacity being more than adequate for current production levels of 0.4 Bcf/d.

Overall the gas transmission infrastructure has been sized with sufficient capacity to allow flexibility of supply across producing fields, with the exception of the NCMA Hibiscus pipeline which has been running at capacity.

NGC manages the Beachfield operations with a gas hub which has 4 Bcf/d capacity feeding 6 major pipelines (including the 36" line owned by bpTT). The pipeline system has Supervisory, Control and Data Acquisition (SCADA) and utilises intelligent pigging, which has confirmed the integrity of the pipelines. NGC is responsible for the transportation of the gas once it makes landfall.

Over the past decade there has been a move to sub-sea completions, which in turn has led to the development of offshore hubs. It is reported by NGC this has had the effect of reducing flexibility to the system as a hub platform going down has shut out several sources of gas. This has prompted the development of some bypass lines around hub facilities to avoid this reoccurring (example of which is the Starfish development).

There is a plan under consideration to reduce the pressure in the 56" pipeline supplying ALNG and add inlet compression. This would allow operating pressure of the 56" line to be reduced by 200 psi which would result in an increased flow from the supplying fields of 250 MMcf/d. Both 36" and 56" lines supplying ALNG would be put on a common header and additional compression capacity would be installed. (Currently only 36" line has compression into the ALNG facility). It is possible that the TGU CCGT power plant at La Brea would need inlet compression as a consequence. ALNG is currently undertaking technical studies into this.

Table 4-3 Gas Processing Infrastructure in T&T

(Source: MEAA)

Ownership	Description	Natural Gas	Condensate	Comments
NGC	The Abyssinia 30-inch Slug Catcher	600 MMcf/d	1,750 bbl/d	This facility forms part of the NGC 30-inch pipeline system.
NGC	Galeota 24-inch Slug Catcher	450 MMcf/d	1,500 bbl/d	This slug catcher is part of NGC's 24-inch diameter pipeline system. With the start-up of the Beachfield slug catcher, this Galeota facility is now in standby/bypass mode.
NGC	Tobago Natural Gas Receiving Facility	100 MMcf/d		NGC's onshore Gas Receiving Facility in Tobago is located at Cove Eco Estate and Business Park. It was designed to operate with two independent processing trains each with a capacity of 100mmscf/d and a metering system for measuring the gas volumes sold. At present only one processing train has been installed.
NGC	Beachfield Slug catcher	3,000 MMcf/d	5,000 bbl/d	This major centralized natural gas and condensate processing facility was constructed to process supplies from NGC's 24-, 30- and 36-inch pipelines in one location.
NGC	Phoenix Park Valve Station (PPVS)	3,000 MMcf/d	3,000 bbl/d	The Phoenix Park Valve Station, with associated facilities, was upgraded to meet the increase demand on the Point Lisas industrial estate to handle more than three billion cubic feet per day.
PPGPL	Phoenix Park Gas Processors Limited (PPGPL)	1,950 MMcf/d	70,000 bbl/d	PPGPL's core business is natural gas processing, NGL aggregation, fractionation and marketing.
BG	Beachfield Onshore Facility	275 MMcf/d	1,500 bbl/d	Expandable to 450 MMcf/d.
BP	Beachfield Gas Receiving Facility		5,000 bbl/d	

Section 5 Upstream: Supply & Contracting Arrangements

5.1 UPSTREAM CONTRACTUAL ARRANGEMENTS

5.1.1 Overview

Unlike other measures, such as regulations and taxes, contractual arrangements are not easily revised to accommodate adjustments in policies. This is particularly true for the gas sector where investment decisions are underpinned by long-term contracts, often for the life of a gas field, which define critical commercial provisions such as take-or-pay terms. Of particular importance are PSCs whose terms over-rule requirements of oil and gas regulations.

Given the commercial sensitivity of contractual arrangements, it was not possible to review the specific terms of all licenses and PSCs, however it was possible to review the provisions of the model PSCs for 2010, 2012 and 2013 and a summary of terms for most shallow-water PSCs.

The upstream portion of T&T's petroleum industry is regulated under a framework composed of the 1962 Petroleum Act, ('Act') and the Petroleum Regulations, ('Regulations'). The Act and Regulations are further supplemented by licences for exploration and production (EPL) and PSCs. This scheme applies equally to petroleum operations that are conducted onshore and offshore[1]. The Act was revised by the addition of Sections 6(3) and 6(4) when PSCs replaced EPLs as the method for granting exploration rights. Section 6(4) allows the Minister to enter into PSCs that over-rule the application of the Act and Regulations. Rather than modify the Act, this structure allows the government to revise a broad range the terms and conditions through the model PSCs that are used for each bidding round[2].

Under the model PSC, a discovery is considered to be a 'Natural Gas Field' when more than 50% of the estimated reserves, on an energy equivalent basis, are natural gas[3]. If a Natural Gas Field can be commercially developed, the term of the PSC where the production area is located can be extended for a period of thirty years[4].

As a general rule, PSC's are designed to encourage diligent development of commercial discoveries by requiring the contractor to either commit to a gas development plan, or relinquish the area within a fixed period of time. However, the model PSC recognises that it may be necessary for the contractor to conduct a market assessment before being committed to a development program. The duration of the market assessment phase should not exceed five years from the date of contractor's notice of a commercial discovery, but the duration depends upon:

- the date the natural gas discovery is declared a commercial discovery, starting the market assessment phase;
- the date that contractor voluntarily surrenders the market development area or seven years after the contractor enters the market development phase under Article 13.3[5].

Beyond this period, the Minister has the discretion to grant two successive extensions of five years each[6]. In total, it is possible that the commitment for the development of an otherwise commercial discovery of

[1] As discussed in Section 6.4 the fiscal regime includes special terms for deepwater petroleum operations
[2] The 2012 and 2013 Model PSC's are relevant for the interval of this Gas Master Plan
[3] Article 1.51
[4] Article 4
[5] Article 16
[6] Articles 4.5 and 4.6

natural gas to be deferred for more than a decade which may conflict with a development schedule required to maintain the overall production plateau.

In T&T appraisal reports that are submitted in the course of determining the commerciality of a gas discovery include an analysis of marketing options in the internal market of T&T[7].

5.1.2 GORTT Production Share

GORTT receives a share of profit production under each PSC based on a 'matrix' that takes into consideration product prices as well as production levels[8]. The increase in State participation under the PSC was offset by a provision that committed the Minister to pay royalties and other taxes assessed on PSC operations from his share of the profit petroleum[9].

The ability for the Minister to influence upstream contractual arrangements for the sale and delivery of natural gas largely depends on the election made under Annex D of the PSC regarding the sale of GORTT's share of natural gas. Under Annex D the Minister has the following options:

1) Joint marketing: GORTT natural gas is sold on the same basis as the contractor's;
2) Joint facilities: Minister participates in the construction of the processing facilities but takes the share of GORTT natural gas in-kind at the outlet of the plant;
3) Cash payment: Contractor makes payment for GORTT natural gas less the cost of production and marketing;
4) Agreed price: Contractor purchases GORTT natural gas;
5) Percentage delivery: GORTT natural gas is taken in-kind based on the maximum monthly availability; or
6) Fixed volume delivery: Fixed daily or annual volume of GORTT natural gas is taken in-kind.

The third option applies by default either if no election is made, or there is a revocation of an in-kind option. Where the Minister elects either the joint marketing or agreed price options, a sales contract is negotiated with the contractor that includes the price and other arrangements for delivery. Otherwise, only in the case of a national emergency can GORTT modify deliveries of gas under the PSC.

There are two noticeable difficulties with the procedure contained in Annex D. Firstly, the marketing plan presented to the Minister is prepared by the Contractor. Thus far the Minister has agreed to joint marketing as proposed by the marketing plans. Secondly, the commitment of GORTT's share of natural gas has not been subject to conditions that allow GORTT to influence how production is allocated between NGC and ALNG when there is insufficient gas available to fully satisfy both customers.

In Poten's view there should be a clear process and criteria for evaluating market development plans submitted under a PSC.

7 Article 13.4(d)

8 The matrix uses a double sliding-scale for production and prices, and is similar to that previously adopted by Indonesia for its offshore exploration blocks.

9 This provision appears as Articles 21.5 and 21.6 in most PSCs.

5.1.3 Domestic Market Obligation

In T&T, commercial aspects of natural gas supply to the internal market is addressed through contract rather than by regulation. There is no obligation for PSC contractors to supply the internal market. The Minister's role in gas marketing is contained in the gas development provisions in of the PSC. Subject to minor limitations, PSC contractors can export any natural gas taken for cost recovery and as profit natural gas, collectively referred to as "available petroleum". GORTT further appears to have committed its share of profit natural gas to the contractor's marketing programs.

In other countries the terms of the PSC include a domestic market obligation (DMO) clause, primarily in regards to crude oil. Generally, there are two approaches to a DMO. Firstly, as in India, natural gas is completely dedicated to the domestic market. Alternatively, a contractor is obliged to make a portion of their share of production available for the domestic market in proportion to all gas produced, up to a fixed percentage of the contractor's total share. The price paid for the DMO gas is fixed in the PSC.

Nevertheless, at least three of the aforementioned options regarding the sale of GORTT's share of natural gas give the Minister to ability to direct that GORTT natural gas is used to supply the domestic market. However, unless the provisions of Annex D have been invoked, GORTT's share of profit natural gas cannot be taken in-kind. Options under the current model PSC for securing gas for the internal market are limited to the following:

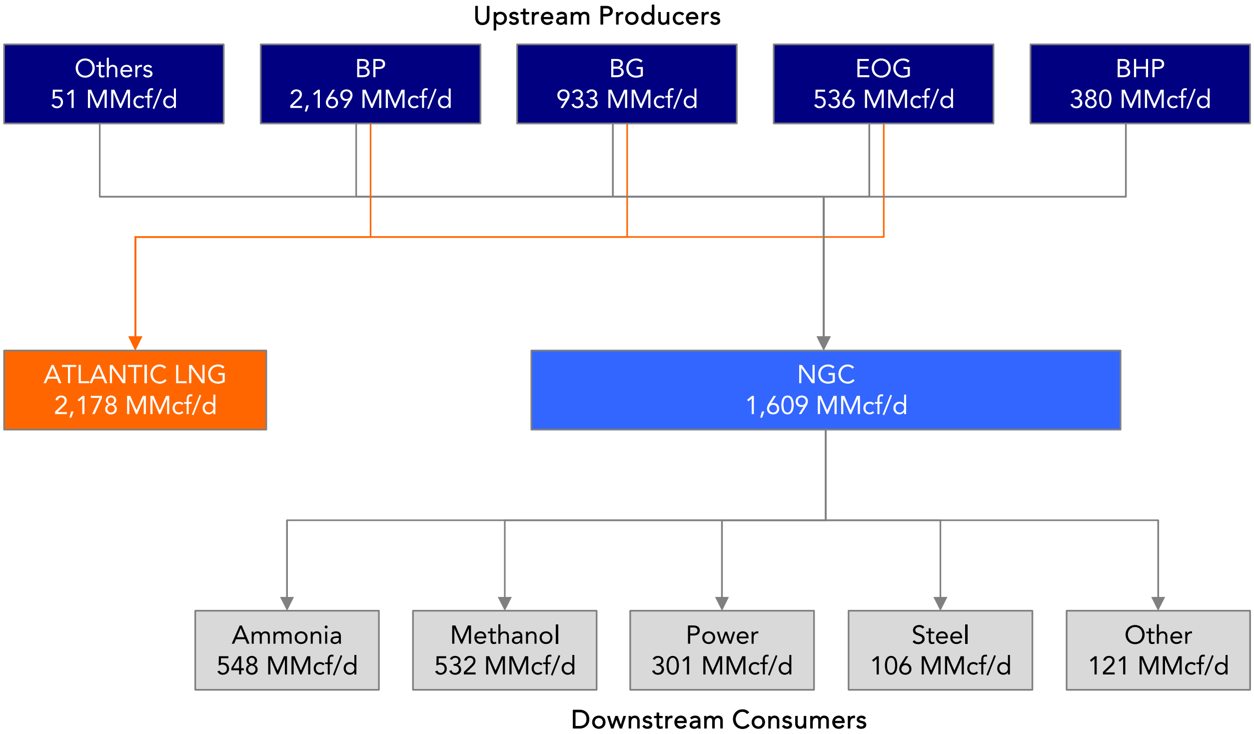
- Negotiation of supply agreements under the conditions of Annex D at the direction of the Minister;
- Requisition under the conditions of a national emergency in accordance with Section 36 of the Act.

As a result, NGC must either take delivery in-kind of GORTT's royalty gas under the EPLs, or negotiate with PSC contractors for gas supply.

5.2 REVIEW OF CURRENT GAS SUPPLY ARRANGEMENTS

Gas produced in T&T is supplied to either NGC or ALNG as illustrated in Figure 5-1.

Figure 5-1 2014 Gas Supply Schematic



5.2.1 Gas Supply to NGC

5.2.1.1 Gas Supply Contracts

NGC currently contracts for around 2.1 Bcf/d of gas to supply the downstream sector in T&T through 11 contracts, as shown in the table below.

It should be noted that Poten only received very limited information about the contracts and was not provided with copies of the contracts themselves. Hence, we are not in a position to comment on specific contractual parameters or commitments.

Typically the original gas purchase contract terms are 15-20 years, and in general the gas contract durations are aligned with PSC contract expiry timelines. We understand that the contracts have Take-or-Pay (ToP) levels of 85-95% of Annual Contract Quantity (ACQ) and an upward flexibility in the form of a Maximum Daily Quantity (MDQ) equal to up to 112-115% of the Daily Contract Quantity (DCQ). The supply contracts typically allow make up gas to be recovered over 5 years.

The contractual structures for gas supply to NGC were developed during a time of gas surfeit when flexibility in volume offtake was required to stimulate downstream industry. Since then the situation has changed to one of shortfall. We understand that while there are obligations in NGC's upstream contracts on the producers to meet supply commitments, in many cases there are no specific penalties for failing to do so. In most contracts we understand that there is the ability to bank gas that is not delivered, with a 5 year expiry term for banked gas.

The major bpTT contract is particularly complex as it covers 6 separate tranches of gas which are supplied in a specific order, and some trances have sub-tranches. Each tranche of gas has specific ToP levels and separate pricing.

Table 5-1 NGC Gas Supply Contracts

(source: NGC Data)

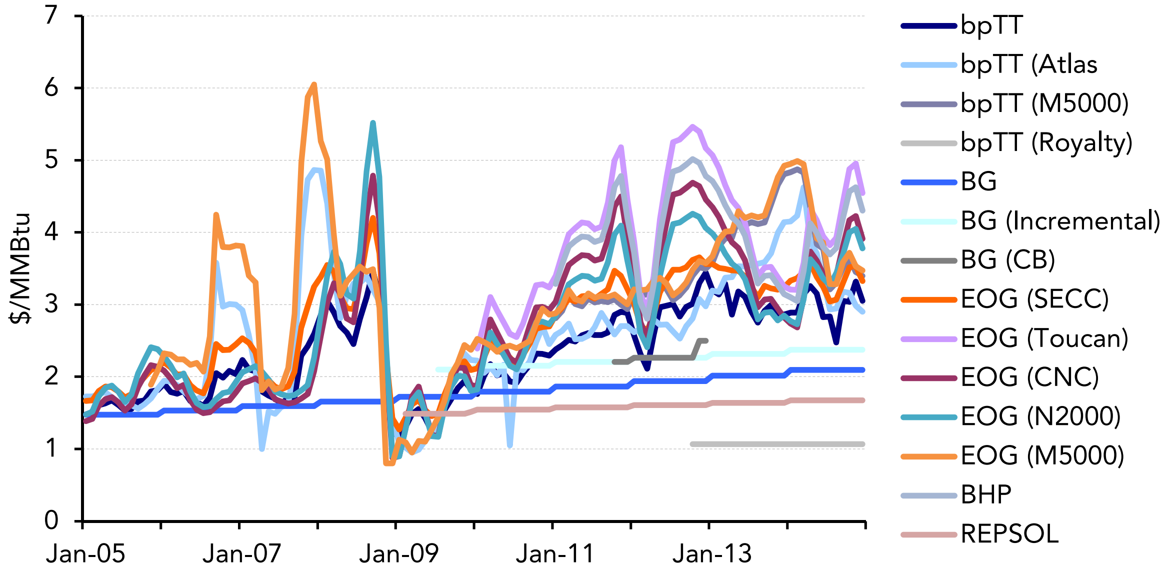
Gas Supplier	Daily Contract Quantity	Contract Expiration Date	Pricing basis
bpTT	645 MMcf/d	31 Dec 2018	Various tranches
bpTT Royalty Gas	160 MMcf/d	31 Dec 2016	See Section 5.2.3
bpTT for Atlas	164 MMcf/d	16 Sep 2014	Netback from methanol prices
BG Base	250 MMcf/d	31 Dec 2015	Flat pricing with escalation
BG Incremental	220 MMcf/d	31 Dec 2019	Flat pricing with escalation
EOG Base	150 MMcf/d	31 Dec 2018	3 tranches with flat price, and linkages to Ammonia, Methanol respectively
EOG Incremental	110 MMcf/d	31 Dec 2024	Linked to HH and netbacks from ammonia prices
EOG for CNC	60,000 MMBtu	26 June 2017	Netback from ammonia prices
EOG for N2000	60,000 MMBtu	23 Aug 2019	Netback from ammonia prices
EOG for M5000	130,000 MMBtu	22 Sep 2020	Netback from methanol prices
BHP	220-245 MMcf/d	22 April 2021	Fixed price and ammonia linkage elements
Repsol	Up to 20 MMcf/d	31 Dec 2018	n/a

In general NGC acts as an aggregator and intermediary for gas supply to downstream consumers, and assumes any volume/price mismatch risk between its contracts for gas purchases and sales, e.g. if an upstream producer fails to supply NGC it does not follow that NGC is relieved of its obligation to supply downstream industries. However, under some upstream contracts tied to specific downstream plants NGC does not take volume risk, although it still acts as an intermediary; this risk is passed back directly between upstream supplier and downstream buyer. Examples of this are bpTT (Atlas methanol) and EOG (CNC/N2000 ammonia; M5000 methanol).

5.2.1.2 Pricing

Much of the gas supply under the different contracts is priced based on end product markets (methanol, ammonia and US Henry Hub gas). The prices paid under the different contracts/traches are shown in the figure below.

Figure 5-2 Historical Gas Pricing from Upstream Suppliers to NGC
(source: NGC)

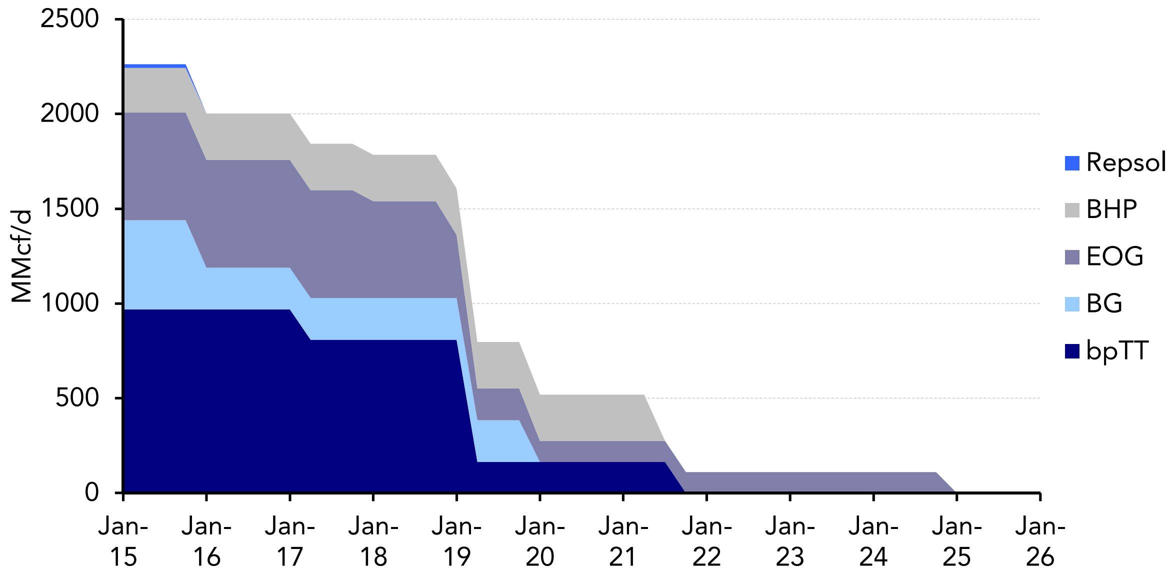


BG's is the only contract not linked to downstream pricing; it is based on a flat price with annual escalation.

5.2.1.3 Contracted Volumes

NGC currently contracts for around 2.3 Bcf/d of gas supply under the contracts discussed previously. Most of these contracts expire within the 2015-19 time period. As shown in the figure overleaf, total volumes contracted by NGC decline to around 2.0 Bcf/d from 2016 and then to less than 1 Bcf/d by early 2019.

Figure 5-3 Contracted Gas Supply Volumes to NGC
(source: NGC)



5.2.2 Gas Supply to ALNG

5.2.2.1 Gas Supply Contracts

Contracts are currently in place to supply an average of 1,469 MMcf/d to ALNG Trains 1-3 (Table 5-2).

Table 5-2 ALNG Gas Supply Contracts

(source: ALNG)

Train	Gas Supplier	Gas Buyer	Annual Contract Quantity (MMcf)	Daily Equivalent (MMcf/d)[#]	Contract Expiration[10]	Pricing Basis
1	bpTT	ALNG Ltd.	161,200	442	2019	Netback fraction of LNG/NGL revenues
2	bpTT	ALNG 2/3 Ltd.	85,966	261	2024	LNG/NGL revenues minus Plant Net Entitlement
2	NCMA (BG)	ALNG 2/3 Ltd.	89,444	249	2024	LNG/NGL revenues minus Plant Net Entitlement
3	bpTT	ALNG 2/3 Ltd.	133,817	395	2024	LNG/NGL revenues minus Plant Net Entitlement
3	NCMA (BG)	ALNG 2/3 Ltd.	16,070	45	2024	LNG/NGL revenues minus Plant Net Entitlement
3	ECMA (BG)	ALNG 2/3 Ltd.	28,156	77	2024	LNG/NGL revenues minus Plant Net Entitlement
	TOTAL			1,469		

[#] Based on daily average of ACQ for 2014/15 from ALNG

In addition, there are processing contracts in place with ALNG Train 4 (tolling facility) totaling an estimated 743 MMcf/d, as shown in Table 5-3. This gives a combined "contracted" gas supply figure to ALNG of 2,212 MMcf/d.

Table 5-3 ALNG Train 4 Gas Processing Contracts

(source: ALNG)

Gas Supplier	Daily Contract Quantity (MMcf/d)[11]	Contract Expiration[11]	Effective Pricing Basis
BP (from bpTT)	281	2025	LNG/NGL revenues minus Processing Fee
BG	215	2025	LNG/NGL revenues minus Processing Fee
Shell (from bpTT)	165	2025	LNG/NGL revenues minus Processing Fee
TTLNG (NGC from EOG & bpTT)	83	2025	LNG/NGL revenues minus Processing Fee
TOTAL	743		

10 Estimate

11 Estimate

It should be noted that Poten only received high level summaries of both the gas supply and processing contracts. Hence, we are not in a position to comment on specific contractual parameters or commitments. Each of the contracts is for 20 years' duration. Buyer ToP levels are 90% for Train 1 and 95% for Trains 2 and 3.

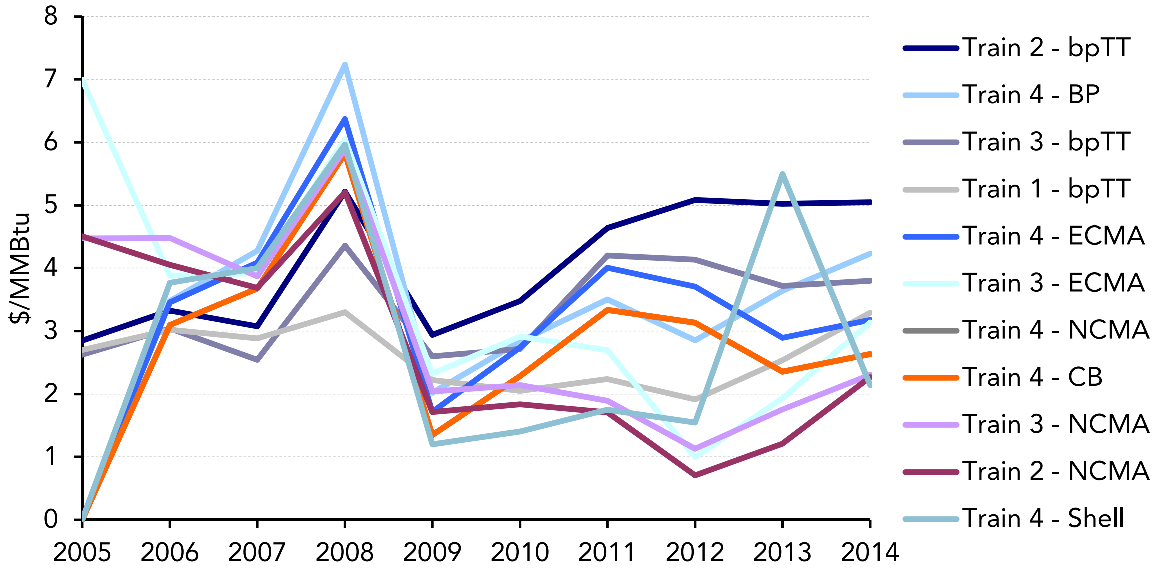
5.2.2.2 Pricing

The pricing realised by upstream producers for supply to LNG is linked to the LNG/NGL revenues realised from the gas supply:

- Train 1: Gas price is ~53% of combined LNG and NGL revenues.
- Train 2: Gas price is equivalent to combined LNG and NGL revenues minus Plant Net Entitlement of ~$1.3/MMBtu of gas supply.
- Train 3: Gas price is equivalent to combined LNG and NGL revenues minus Plant Net Entitlement of ~$1.1/MMBtu of gas supply.
- Train 4: Effective gas price (tolling facility) is equivalent to combined LNG and NGL revenues minus Processing Fee of ~$1.3/MMBtu of gas supply.

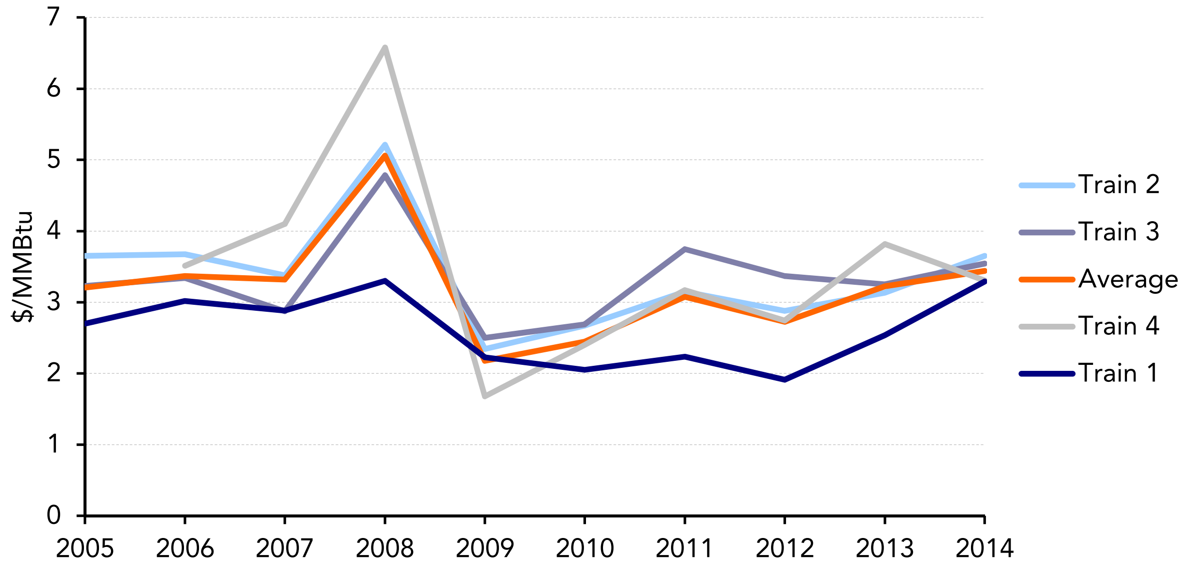
Historical pricing under these arrangements is shown in Figure 5-4. There are clearly significant disparities realised by the different tranches of upstream supply to the different trains. For example, realised pricing under the different arrangements in 2014 is estimated to have ranged between $2.14/MMBtu and $5.05/MMBtu. These differences can be explained by the specifics of the downstream LNG supply arrangements associated with the particular tranches of gas supply. Details of these arrangements how they relate back to upstream are provided in Section 10.

Figure 5-4 Historical Gas Pricing to Upstream Suppliers from ALNG
(source: ALNG, MEEA)



The gas prices paid by TTLNG/NGC for Train 4 supply from bpTT and EOG are not included as they are part of NGC's general gas supply contracts and are not linked to downstream LNG sales. These contracts are covered in Section 5.2.1.

Figure 5-5 Historical Gas Pricing to Upstream Suppliers from ALNG by Train
(source: ALNG, MEEA)

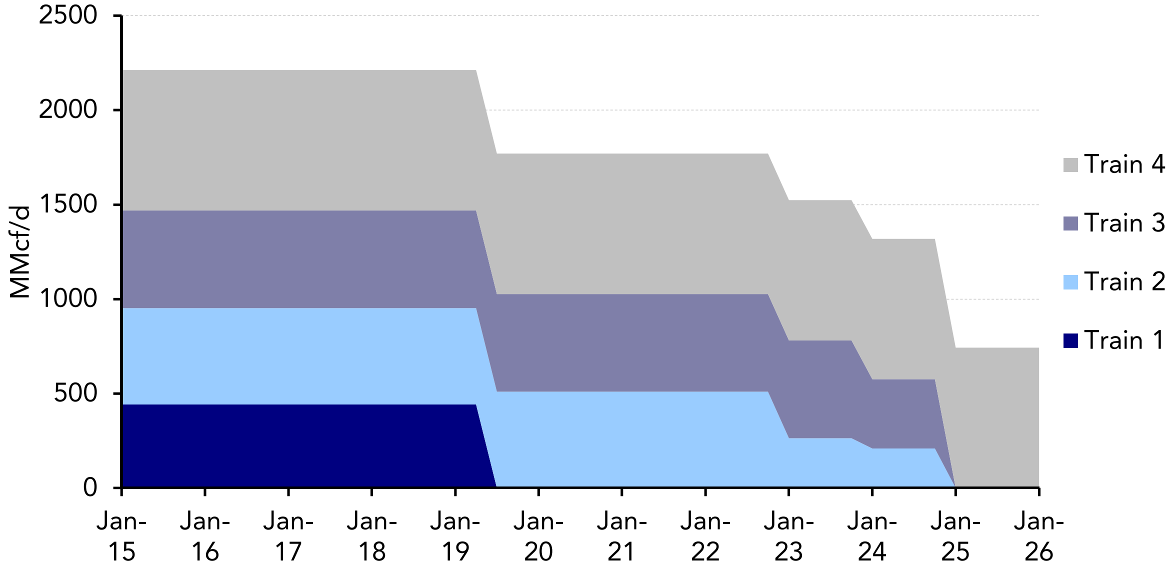


The figure above show weighted average prices realised by upstream for supply to each train and overall. The average gas price for supply to ALNG is estimated at $3.44/MMBtu for 2014.

5.2.2.3 Contracted Volumes

Including the processing contracts in place with Train 4 (tolling facility) the combined "contracted" gas supply figure to ALNG is 2,212 MMcf/d. As shown in the figure below, this declines to around 1,770 MMcf/s from 2019 with the expiry of the Train 1 supply contract. Contracted volumes are then maintained into 2023 when the Train 2/3 gas supply / LNG offtake arrangements begin to expire.

Figure 5-6 Contracted Gas Supply Volumes to ALNG
(source: ALNG)



5.2.3 Utilisation of Royalty Gas

In addition to the gas which is contracted from upstream suppliers NGC receives gas from bpTT on behalf of GORTT. The original agreement came about in 2004 when GORTT sought to renegotiate the royalty provisions in bpTT's gas supply contract for gas supply that was used for LNG. The key element of the revised arrangement is that the royalty of 10% is honoured in kind, i.e. in the form of gas, rather than cash. Poten understands that the original driver for this was the GORTT desire to secure low cost gas that could be used for NGC and provided to industries that it was government policy to encourage, such as aluminium (which ultimately, did not materialise), and for power generation.

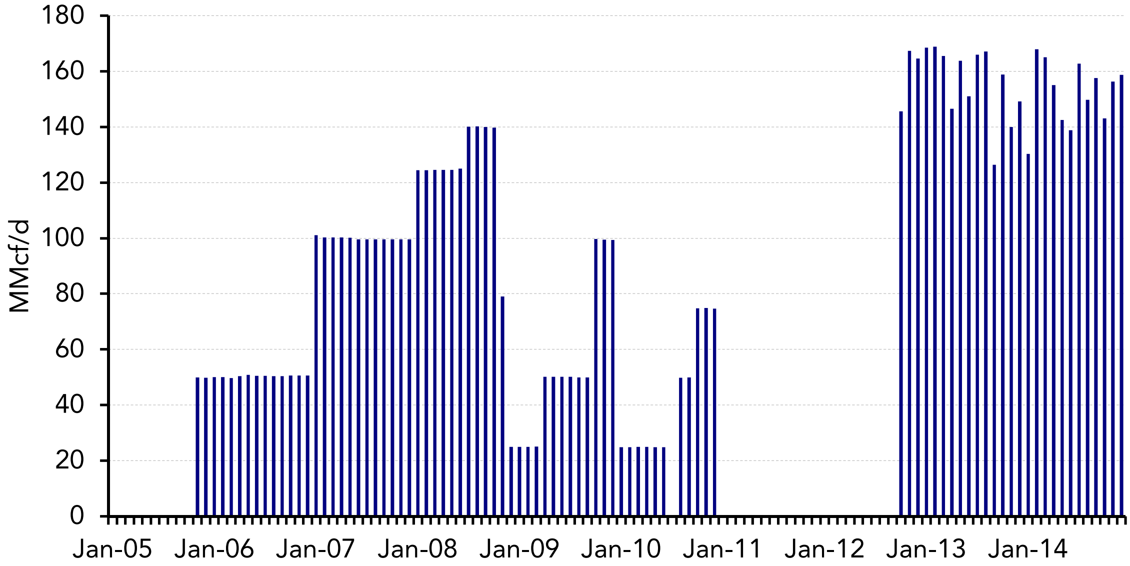
There is no fully termed contract for this arrangement, but under an agreement known as the "2005 principles" bpTT provides natural gas to GORTT in lieu of royalty payments for the following volumes:

- 50 MMcf/d from October 2005.
- 100 MMcf/d from 1st January 2007.
- 10% of gas sold (by bpTT) for LNG from 1st January 2008 .

The "2005 principles" provides these volumes of gas at a price $0/MMBtu, and as such bpTT considers the agreement a commercial arrangement. The arrangement ends in 2016. GORTT has nominated NGC to receive this gas. Initially NGC did not pay GORTT for this gas and used it to provide low cost gas to the power sector, local customers and steel.

For a period of time after Q4 2010 NGC was unable to take the gas in kind due to insufficient market demand. Royalty gas take was restarted in October 2012 under low supply conditions, however since the restart MEEA has requested payment. GORTT is being paid at the rate of T&TEC gas price less a US$0.12/Mcf tariff. GORTT payments are only being made when NGC is paid. T&TEC is paying NGC at a 'frozen' rate of US$1.1818/MMBtu until final determination by RIC on pricing.

Figure 5-7 Royalty Gas Supply 2005-2014
(source: NGC, MEEA)



Initially NGC was receiving the full benefit of the Royalty Gas, as it received the gas at zero cost. The gas was sold to the portfolio of downstream suppliers so would have effectively realised the average sales price. Under the amended arrangements from October 2012 the company has passed on some benefit to GORTT. In 2014 NGC received an average of ~150 MMcf/d of royalty gas, which at the above price would have provided around US$ 70 million to GORTT. Given that the weighted average selling price of NGC was around $4.1/MMBtu in 2014 then NGC would have made around US$240 million gross margin from the sales of royalty gas. To the extent that NGC distributes this revenue back to GORTT in dividends this represents economic rent capture by GORTT. (The NGC dividend in 2013 was $230 million).

Given that the Royalty Gas arrangements end in 2016 under the present agreement this leaves little opportunity for a more strategic option such as storage etc. and in any case the downstream market clearly needs the gas as it is produced.

5.3 SECURITY OF SUPPLY

5.3.1 Supply to NGC

Figure 5-8 overleaf shows annual average gas supply to NGC from the different upstream gas producers from 2005 to 2014, while Figure 5-9 shows monthly gas supply over the same period. Estimated supply from bpTT has dropped significantly below the contracted level (969 MMcf/d) over recent years, declining from a peak of 917 MMscf/d in 2007 to 613 MMcf/d in 2014. Declining supply from bpTT has at least partially been attributed to increased maintenance and asset integrity reviews post the Macondo disaster.

Supply from BG (estimated peak of 384 MMcf/d in 2012 to 311 MMcf/d in 2014) and EOG (estimated peak of 497 MMcf/d in 2010 to 450 MMcf/d in 2014) has also declined although less markedly. BG supply has also suffered significant annual outages due to maintenance. BG and EOG's supply levels have dropped significantly below their contracted volumes of ~470 MMcf/d and ~570 MMcf/d respectively. New supply from BHP from 2011 has maintained total supply levels to NGC as supply from other producers has declined. Total supply to NGC peaked at an average of ~1,760 MMcf/d in 2011 and was ~1,610 MMcf/d in 2014. Critically, total supply to NGC has been well below its total current supply contract volume of 2.25 Bcf/d.

Shortfalls in contracted gas supply volumes to NGC have had a knock-on effect on the ability of NGC to meet its downstream gas supply commitments, as is discussed in Section 11.

Figure 5-8 Estimated Historical Annual Average Gas Supply to NGC
(source: MEEA, NGC)

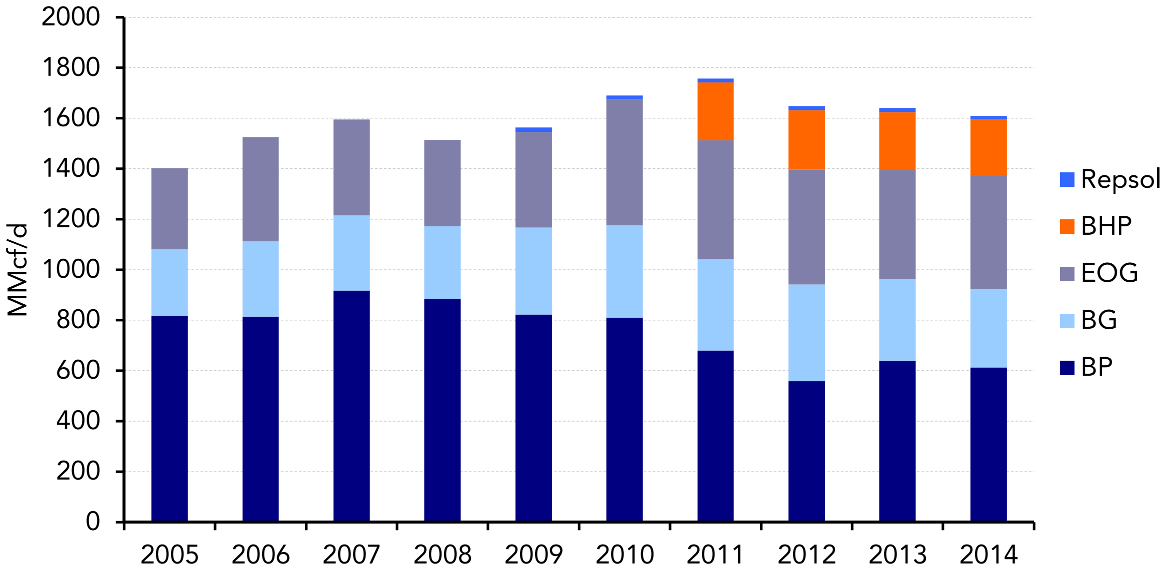
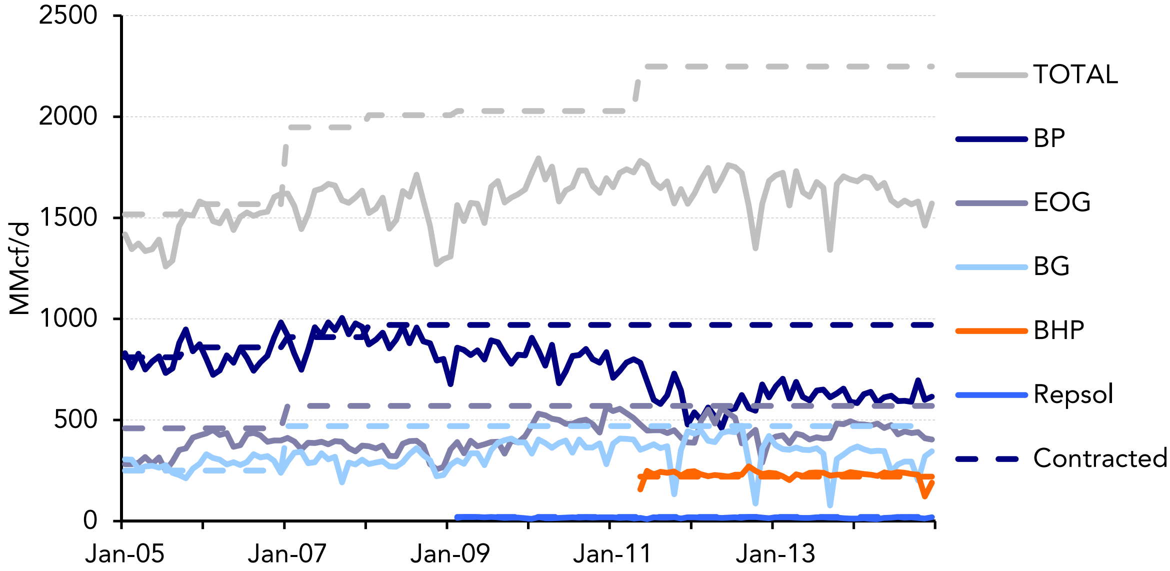


Figure 5-9 Estimated Historical Monthly Contracted & Delivered Gas Supply to NGC
(source: MEEA, NGC)



Another significant issue for NGC has been the short-term variability in supply due to outages etc. As can be seen in Figure 5-9, supply from BG has been particularly affected by a number of major disruptions since 2011.

5.3.2 Supply to ALNG

Figure 5-10 shows historical annual average supply to ALNG from 2005 to 2014, by company where data has been provided. Monthly figures over the same period are shown in Figure 5-11.

Total supply to ALNG peaked at an average of 2,321 MMcf/d in 2010 and was 2,178 MMcf/d in 2014, representing a decline of 6.1% from peak supply. However, in contrast to the position of NGC, supply to LNG has been largely maintained at the level of contractual supply commitments, which are estimated at 2,212 MMcf/d for 2014/15 (average supply was around 2% below this figure in 2011, 2012 and 2014).

Most of the decline can be attributed bpTT, which has seen its estimated supply to ALNG decline from a peak of 1,673 MMcf/d in 2010 to 1,552 MMcf/d in 2014; a reduction of 7.2%. BG's supply to ALNG has declined less substantially from a peak of an estimated 619 MMcf/d in 2010 to 598 MMcf/d in 2014; a reduction of 3.3%.

Figure 5-10 Estimated Historical Annual Average Gas Supply to ALNG
(source: MEEA, ALNG)

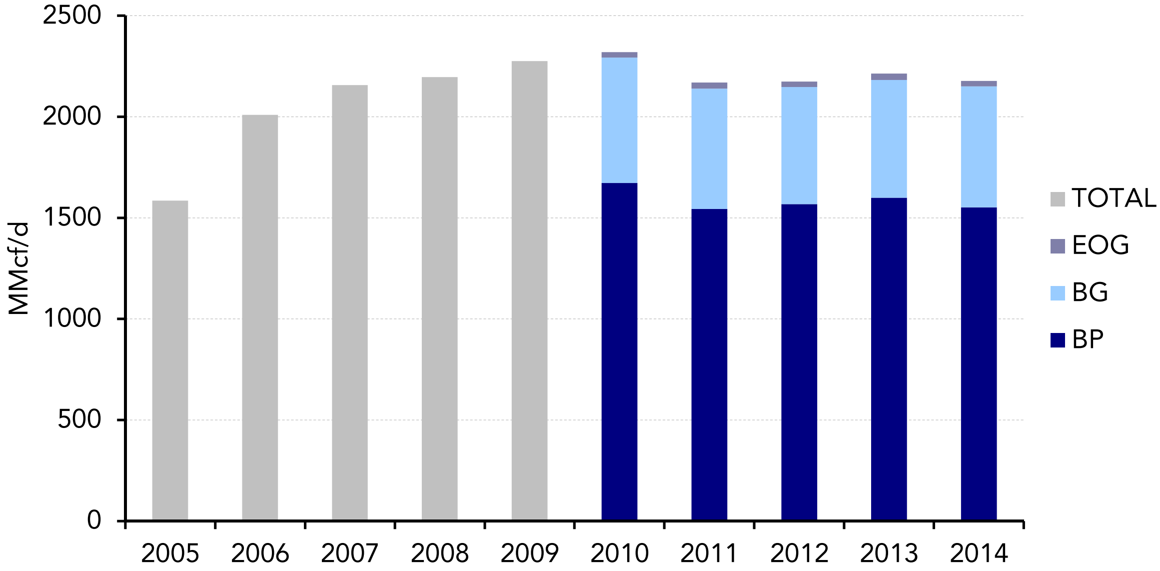
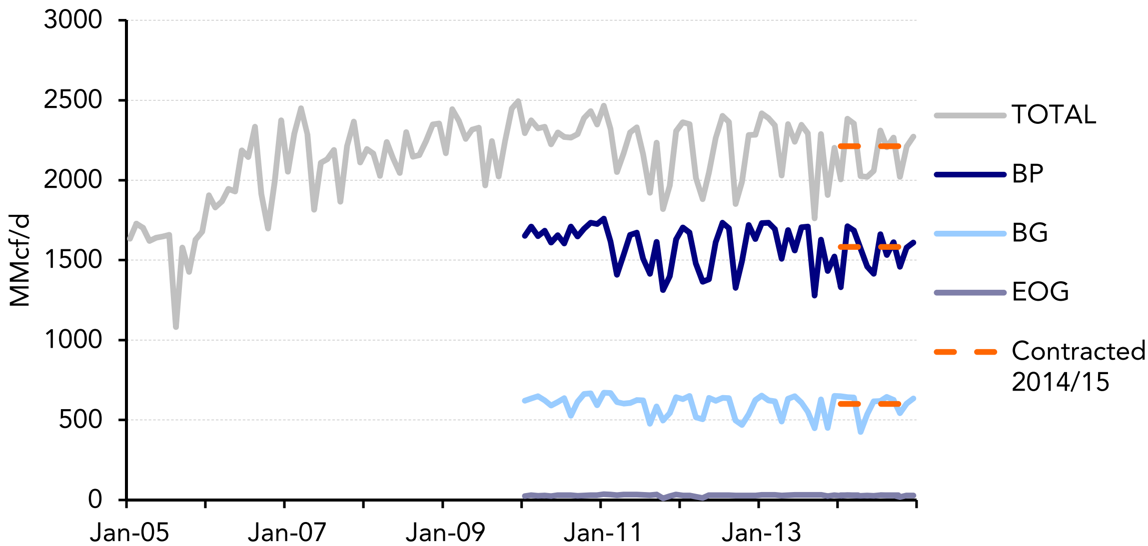


Figure 5-11 Estimated Historical Monthly Contracted & Delivered Gas Supply to ALNG
(source: MEEA, ALNG)



Monthly gas supply to ALNG has also been subject to significant fluctuations, although they have been less significant in terms of overall supply than the short-term declines experienced by NGC in 2012 and 2013. It is noted that BG's supply to ALNG has proved substantially more stable than its supply to NGC.

5.3.3 Gas Storage Potential

In 2014 NGC undertook a study to investigate the possibility of developing gas storage to manage short-term gas supply fluctuations. The criteria were to ensure that NGC could provide 1,750 MMcf/d of gas supply without curtailment, using the storage volumes to back stop the primary supply contracts and smooth out intra-week shortfalls. The study looked at the storage capacity required to manage the supply variations that were experienced by NGC in 2013 and determined that the storage facility should have the following parameters:

- 5 Bcf of working capacity.
- 200 MMcf/d minimum deliverability.
- 100 MMcf/d injection capacity.

In addition it was identified that 155 MMcf/d of additional gas supply capacity would be required to meet NGC's supply requirements and enable injection into storage. Where this would come from is not addressed in the documentation provided, which is clearly a key issue.

The capital costs for the storage were identified as follows:

- Total facility costs: $198 MM
- Cost to fill storage (50 Bcf cushion gas): $132 MM

The operating costs were estimated to be $5 MM per annum.

A 10% IRR was identified as a target for the project, but the economics of the project or the tariff that would be required to provide such a return were not detailed in the documentation provided.

The Mahaica abandoned gas field was identified as the primary candidate. This is a sandstone reservoir located 15 miles from Port of Spain on the NGC pipeline. The field was drilled in 1979 and abandoned after limited gas production. Of the technical risks identified the most concerning is that the reservoir dimensions are uncertain. Seismic and drilling are proposed to better visualise the reservoir parameters.

5.3.4 Conclusions & Recommendations

The relatively low exploration success in the last decade has resulted in a decline in deliverability of the producing gas reservoirs as larger fields deplete and increasingly small and marginal fields are brought onstream to fill the supply gap. The decline in available deliverability over recent years has led to increasingly frequent supply curtailments to both NGC and ALNG. Critically for NGC its average supply levels have been well below the contracted volumes, in contrast to ALNG where average supply levels have largely been maintained at least at contractual commitment levels. Shortfalls in contracted gas supply volumes to NGC have had a knock-on effect on the ability of NGC to meet its downstream gas supply commitments, as is discussed in Section 11.

The contractual structures for gas supply to NGC were developed during a time of gas surfeit when flexibility in volume offtake was required downstream. It was not necessary to impose firm delivery requirements on upstream suppliers from when gas deliverability was sufficient for suppliers to compensate for outages in individual fields by increasing production elsewhere. However, as deliverability has declined the frequency of supply shortfalls has increased due to planned and unplanned production system shutdowns reducing the total deliverability of the supply system. This has led to a shortfall in annual supply to NGC's downstream customers and greater variability in day-to-day levels of supply as the gas producers do not have deliverability to compensate for shortfalls in gas from one field by increasing production from another. In previous years, when there had been a surplus of supply capacity, these effects were not felt.

In the absence of any penalties being imposed on suppliers for shortfalls in gas delivery to NGC, suppliers are left to make their own decision on whether the limited supply of gas should be sent to ALNG or NGC. The disproportionate curtailment of gas supply to NGC by upstream suppliers in favour of ALNG is likely a result of the somewhat higher prices paid by LNG in some cases and, most importantly, the upstream suppliers' overall commercial position along the LNG supply chain, i.e. the upstream supplier receives additional rent from the downstream LNG chain which encourages them to supply LNG preferentially.

There is also no requirement or financial incentive for suppliers to maintain excess deliverability (swing or cushion gas) which would allow them to compensate for supply reductions in other parts of the production system. As the gas system approaches the end of plateau production, deliverability will depend on depleted mature fields and an increasing number of small field developments which will typically have high depletion rates and limited excess deliverability. The vulnerability of the system to outages in individual fields will consequently tend increase over time.

Supply interruptions can be reduced by ensuring that there is sufficient deliverability in the gas production system to allow production to be increased to compensate for planned and unplanned shutdown of individual elements of the system. This can be addressed from two perspectives:

- Reduce the magnitude of supply shortfalls caused by shutdowns of system elements.
- Increase the available deliverability of the gas supply system.

Reducing the impact of shutdowns can be addressed to some extent by better planning of maintenance programmes between producers to avoid too many production systems being off line for maintenance at any given time. However the system will still be exposed to unplanned shutdowns.

Increasing system deliverability requires investment, primarily in additional wells or field compression, given that gas treatment and transportation systems have demonstrated sufficient capacity in the past. This could take the form of accelerating current development plans to increase short-term production capacity before existing fields decline. Producers can be incentivised to do this by:

- Requiring excess deliverability in new supply contracts (difficult to measure and verify).
- Offering an additional tariff for maintaining reserve capacity (difficult to measure and verify).
- Paying a premium for interruptible gas.

These measures risk being inefficiently prescriptive or open to manipulation. In general the production operator is best placed to determine the most efficient approach to maintaining reliable supply to the consumers and the approach most often used in gas supply contracts is "Ship or Pay" terms which apply a penalty on the producer for failure to supply gas within the terms of the contract. This allows more granular definition of terms, for instance with an obligation to supply to the Daily Contract Quantity (DCQ) level, with incremental supply up to the Maximum Daily Quantity (MDQ) on a best efforts basis. This also provides a counterbalance to the upstream supplier's financial incentive to preferentially supply a related party consumer, in this case ALNG. As Poten has not been provided with specific details of the existing upstream supply contracts we are not in a position to comment on the extent to which "Ship or Pay" or equivalent terms are already contained in the contracts.

Poten has also been provided with limited information on a gas storage project which aims to compensate for short-term reductions in gas supply by producing gas stored in a depleted reservoir. The proposal acknowledges that overall gas supplies must be increased by 155 MMcf/d if the planned deliverability of 200 MMcf/d from the storage project is to be workable. However, Poten's view is that the investment required in wells and facilities for the storage concept would likely be better spent on increasing offshore deliverability and supply security to avoid the shortfall occurring in the first place. We are not aware of any other examples of where a gas storage project has been developed to cater for a largely export-based gas sector with a flat demand profile such as T&T. Delivery requirements under gas supply contracts are usually relied upon to ensure steady supply, rather than external storage.

In all cases the supplier who fails to deliver gas and causes the shortfall to occur should bear some of the cost of measures taken to compensate for that shortfall, potentially through contract penalties. However the consumers must also accept that continuity of supply has a value that has not to date been reflected in the gas prices they have paid to date and that they must bear part of this cost in the future.

6.1 INTRODUCTION

Addressing the dual challenges facing T&T's gas producing industry of maintaining shallow water production levels and exploring for new fields in deepwater areas will require significant capital investment by International Oil Companies (IOCs). T&T must compete with investment opportunities in other countries to attract a share of the limited exploration and development funds available. The competition for funds has been exacerbated by the current period of low oil prices and many companies have reacted quickly in response to the recent fall in oil prices by cutting expenditure.

In order to assess the competitive position of T&T, a benchmark group of gas producing countries has been selected with similar gas industry characteristics: countries with similar gas reserves and production with both domestic and international market links, particularly LNG export, and countries that are engaged in marginal field and/or deepwater developments, with a preferred focus on Latin America.

There will always be a natural commercial tension between the IOCs and host countries. An IOC's primary concern will be in securing their rights to monetise the reserves, in an attractive, stable and enforceable environment. Host countries will generally look for a fair revenue share, limited exposure to exploration risk, local economic development, and control over the sector. Our assessment was based on consideration of factors important to IOCs considering investment opportunities:

- Is the reserves position attractive?
- Is there an accessible market for gas?
- Are the fiscal terms attractive?
- Is the country business culture attractive?

Our review of benchmark candidates has paid particular attention to countries in which oil and gas companies already active in T&T are investing in exploration and production opportunities.

6.2 T&T FISCAL REGIME

The fiscal terms in T&T have evolved significantly over the preceding decades. The early years of the industry were administered under a Production License (PL) tax and royalty regime. In the 1990s Production Sharing Contracts (PSCs) were introduced in addition to existing PLs. Under the PSC regime, GORTT take was based on the allocation of a share of production thresholds rather than the fixed royalty under the PL. Profit production split is determined by a 'matrix' that takes into consideration prices as well as production levels. The increase in state-take under the PSCs was off-set by a provision that committed the Minister to pay royalties and other taxes assessed on PSC operations from his share of the profit petroleum.

6.2.1 PL Tax and Royalty

Exploration and production licensees must pay a royalty at a rate stipulated in the license on the net petroleum won and saved from the licensed area. Historically, applicable royalty rates have ranged from 10% to 15% for crude oil and US$0.015/Mcf for natural gas.

T&T has placed a higher rate of taxation on the oil and gas industry compared to other sectors of its economy. For example, non-petroleum businesses are liable to a corporate tax of 25%, which is globally competitive. In contrast, Petroleum Profits Tax, which is the equivalent of the tax on corporate income, is 50% in shallow water areas and 35% where production is in deep water (defined as blocks with more than half the area at depths greater than 400 m). In addition to the Petroleum Profits Tax, the following taxes and levies are imposed on petroleum production:

- Supplemental Petroleum Tax (SPT): SPT is imposed on the gross income from the sale of crude oil (including condensate) of companies liable to petroleum profits tax, calculated at a rate which varies with the price of oil. Discounted rates apply for new fields and deepwater fields. These rates are further discounted by 20% for mature and small marine oil fields;

Table 6-1 Supplemental Petroleum Tax Reference Rates

Crude Oil Price ($/bbl)	Standard Rates	New Field	Deepwater
<50	0%	0%	0%
50 to 90	33%	25%	18%
90 to 200	= SPT rate +0.2%(Crude P - 90)		
> 200	55%	47%	40%

- Investment tax credit of 20% of qualifying capital expenditure incurred in either:
  - Approved development activity in mature marine oil fields and mature land oil fields
  - Acquisition of machinery and plant for use in approved enhanced oil recovery projects

- Petroleum Production Levy: PPL is levied pro rata on every production company with the revenue used to pay a subsidy to petroleum marketers. The maximum charge that can be made is 4% of gross income from the production of crude oil. Small producers with a daily average production of 3,500 barrels or less are exempted.

- Petroleum Impost: Every exploration and production licencee is obliged to pay a petroleum impost in respect of petroleum won and saved at rates per Mcf specified by the Minister. The applicable rate varies and is usually published on an annual basis.
- Green Fund Levy: GFL is charged at the rate of 0.1% of the company's gross income, and applies even if the business is exempt from business levy. Green Fund Levy cannot be credited against corporation tax or business levy and so is an additional tax.
- Unemployment Levy: 5% on the profits of companies subject to the Petroleum Taxes Act.

Deductions are allowed for capital depreciation and ordinary business expenses as well as Supplemental Petroleum Tax paid for the period, Petroleum Impost, Production Levy and Royalty. GORTT's profit share allocated under a PSC is not an eligible deduction for tax purposes. Depending on the level of reinvestment, the total current tax rate would appear to reach 65%.

Table 6-2 Depreciation Rates

Spend Category	Capital Depreciation
Exploration	Intangible & tangible 2014 to 2017 (Yr. 1) - 100% of costs Intangible & tangible 2018 onward (Yr. 1) - 50% of costs (Yr. 2) - 30% of costs (Yr. 3) - 20% of costs
Development	Intangible & tangible expenditure (Yr. 1) - 50% of costs (Yr. 2) - 30% of costs (Yr. 3 - 20% of costs
Work Over & Qualifying Sidetracks	100% deduction of all tangible and intangible costs incurred
Deep Horizon Uplift *TVD of 8,000 feet on land or 12,000 feet in shallow marine areas*	1 January 2013 to 31 December 2017 140% of spend
Deepwater allowance *>50% of block at >400m*	140% of spend

6.2.2 PSCs

PSCs contain a tax indemnification provision where income/profit based taxes are reimbursed out of GORTT's share of production. The Petroleum Production Levy and Subsidy Act contains a provision that allows PSC Contractors to 'contract out' of the levy. If the provisions of the PSC conflict, or are at variance with this Act, the provisions of the PSC prevail. This renders the PSCs free of tax apart from Green Fund and Unemployment levies, leaving the rate of cost recovery and the split of profit production as the key fiscal terms in the PSC.

The speed of cost recovery is determined by a schedule of when costs are amortised for recovery and the proportion of annual revenue that can be allocated to the recovery of costs. In shallow-water areas exploration costs are expensed in the year that they are incurred. Early (1996-2005) PSCs depreciated development capital at 40% in the year following the expense, and 20% for the subsequent 3 years. In later PSCs (2011-12) development capital is expensed in the year that it is incurred. The proportion of revenue available for cost recovery is typically capped at 50-60% in shallow-water PSCs. The more recently awarded deepwater PSCs allowed development capital to be expensed in the year that is incurred and raised the ceiling on cost recovery to 80% of annual production.

There is a significant range of profit split terms in current PSCs and a thorough review of the terms made available for this Master Plan can be found in Section 8. In general the contractor share of profit gas ranges from 15-30% at high production rates to 40-70% at low production rates. Variation within these ranges is driven by gas price and individual PSC terms. The indexing of profit production split to gas price has evolved over the years. The first two PSC's awarded in 1974 and 1993 had no gas price index on profit production split. From 1996 PSCs became the primary structure for new acreage release and indexing of profit split to gas prices was introduced. Early PSC (1996-2005) terms were linked to what are now unrealistically low gas prices ranges ($1-$3/Mcf) compared to more the gas price ranges in more recent PSC terms ($3-$7/Mcf). This has resulted in a two-tier system:

- Holders of older PSCs (1996-2002, 2005) are burdened by low contractor profit gas splits at even moderate gas prices by present standards.
- Holders of later PSCs (2011-12) and those without gas price indexing of profit splits (1974, 93) operate under terms intended by the original negotiation.

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6.3 SELECTION OF BENCHMARK COUNTRIES

Benchmark countries have been selected based on consideration of their reserves and production characteristics, their experience with mature production areas and deepwater exploration plays, and the recent investment behaviour of companies already active in T&T.

6.3.1 Gas Reserves and Production

In the Statistical Review of World Energy published by BP in 2015, T&T ranks 34th for proven gas reserves globally as of 31st December 2014. T&T held estimated volumes of 12 Tcf at that time, equating to 0.2% of global gas proven reserves of more than 6,500 Tcf. T&T holds relatively small gas reserves compared to the world's top five resource holding countries which hold 62% of world reserves, the top 10 with more than 78% and the top twenty with almost 92%. Comparison of gas production characteristics provides a more meaningful peer group of benchmark countries. Figure 6-1 and Figure 6-2 summarise current and recent gas production characteristics of countries with similar gas production levels and access to a combination of domestic and international gas markets.

Table 6-3 Proven Gas Reserves (as of the end of 2014)

(source: BP Statistical Review of World Energy 2015)

Rank	Country	Proven Gas Reserves Tcf	World share
1	Iran	1201	18.2%
2	Russian Federation	1153	17.4%
3	Qatar	866	13.1%
4	Turkmenistan	617	9.3%
5	US	345	5.2%
6	Saudi Arabia	288	4.4%
7	United Arab Emirates	215	3.3%
8	Venezuela	197	3.0%
9	Nigeria	180	2.7%
10	Algeria	159	2.4%
11	Australia	132	2.0%
12	Iraq	127	1.9%
13	China	122	1.8%
14	Indonesia	102	1.5%
15	Canada	72	1.1%
16	Norw ay	68	1.0%
17	Egypt	65	1.0%
18	Kuw ait	63	1.0%
19	Kazakhstan	53	0.8%
20	Libya	53	0.8%
21	India	50	0.8%
22	Other Africa	42	0.6%
23	Azerbaijan	41	0.6%
24	Uzbekistan	38	0.6%
25	Malaysia	38	0.6%
26	Netherlands	28	0.4%
27	Oman	25	0.4%
28	Ukraine	23	0.3%
29	Vietnam	22	0.3%
30	Pakistan	20	0.3%
31	Brazil	16	0.2%
32	Peru	15	0.2%
33	Mexico	12	0.2%
34	**Trinidad & Tobago**	**12**	**0.2%**
35	Argentina	12	0.2%
36	Bolivia	11	0.2%
37	Other Asia Pacific	10	0.2%
38	Syria	10	0.2%
39	Myanmar	10	0.2%
40	Brunei	10	0.1%
41	Yemen	9	0.1%
42	Bangladesh	9	0.1%
43	United Kingdom	9	0.1%
44	Thailand	8	0.1%
45	Other Europe & Eurasia	8	0.1%
46	Israel	7	0.1%
47	Bahrain	6	0.1%
48	Colombia	6	0.1%
49	Papua New Guinea	5	0.1%
50	Romania	4	0.1%
51	Poland	3	0.1%
52	Other S. & Cent. America	2	<0.1%
53	Italy	2	<0.1%
54	Germany	2	<0.1%
55	Denmark	1	<0.1%

Table 6-3 identifies a broad peer group based on 2014 production levels that includes many of the world's key LNG producers and significant gas producers in Latin America.

Figure 6-1 2014 Gas Production in Selected Countries

(source: BP Statistical Review of World Energy 2015)

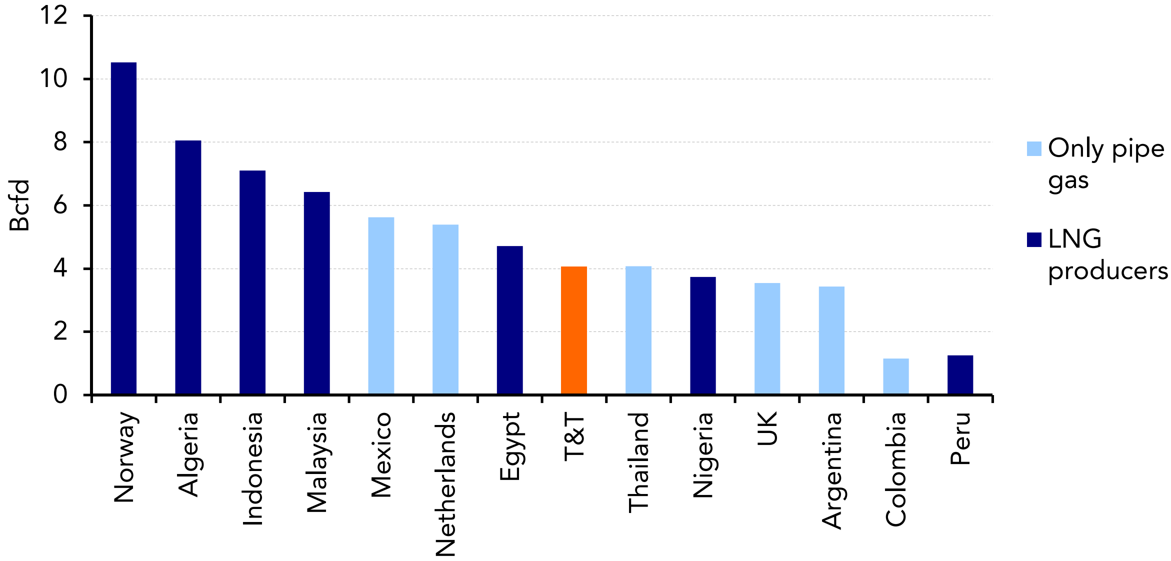


Figure 6-2 Historical Gas Production in Selected Countries

(source: BP Statistical Review of World Energy 2015)

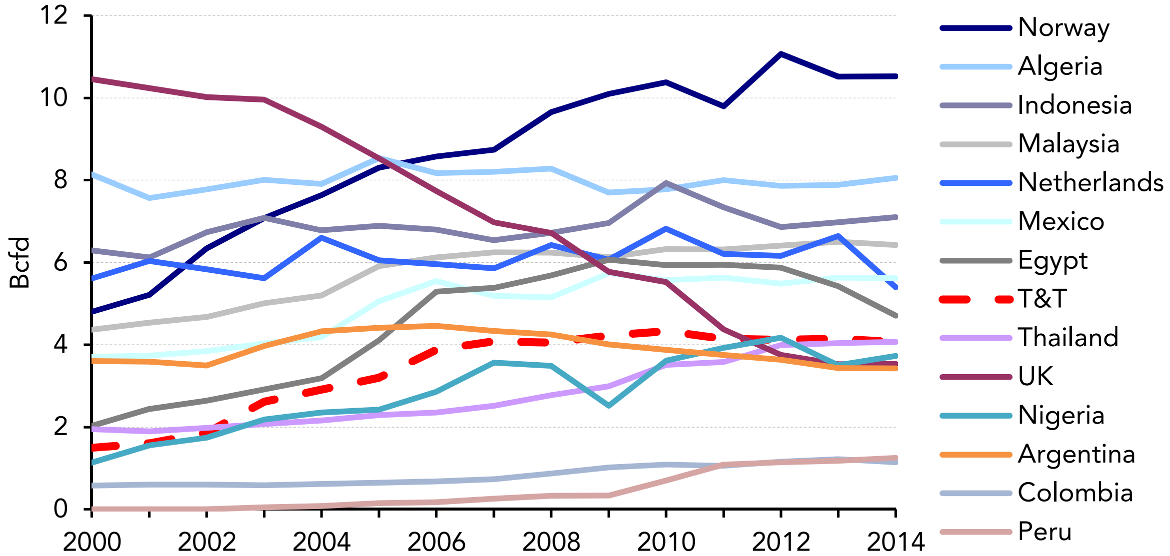


Figure 6-2 presents gas production levels since 2000 for this peer group and allows categorisation into countries with growing production (e.g. Norway and Nigeria), plateaued production (e.g. T&T, Algeria, Indonesia, Mexico, Egypt) and declining production (e.g. UK and Argentina).

The parallels with countries currently on plateau or which are already in decline will be particularly relevant for comparison with T&T.

6.3.2 Deepwater Developments

T&T is in the early phases of attracting investment in its deepwater acreage. A review of the activities of IOCs with particular deepwater skills will assist in identification of countries with whom T&T must compete for these funds.

Many major energy companies and quite a few smaller players are exploring unproven or recently proven deepwater and ultra-deep frontiers. T&T's deep and ultra-deep license blocks have water depth analogues in other countries that have been successful in attracting investment in recent years in competition with T&T. In some cases it has been the more adventurous small players that have demonstrated the viability of new development areas well ahead of the majors and super-majors.

Kosmos Energy of Texas surprised the world by pushing Ghana to adopt E&P licensing terms attractive enough to encourage very successful exploration campaigns. Their first deepwater discovery in 2007, the Jubilee field, is now producing over 100,000 bbl/d. It is surrounded by additional commercial discoveries and has attracted major international players to a country that was ignored for decades, even by companies developing assets in nearby Nigeria. According to Kosmos' website, "success at Jubilee was the result of the company's identification of the overlooked Upper Cretaceous structural-stratigraphic play concept along the Transform Margin of Africa. It was one of the largest finds of 2007 worldwide, and the largest find of the entire decade offshore West Africa."

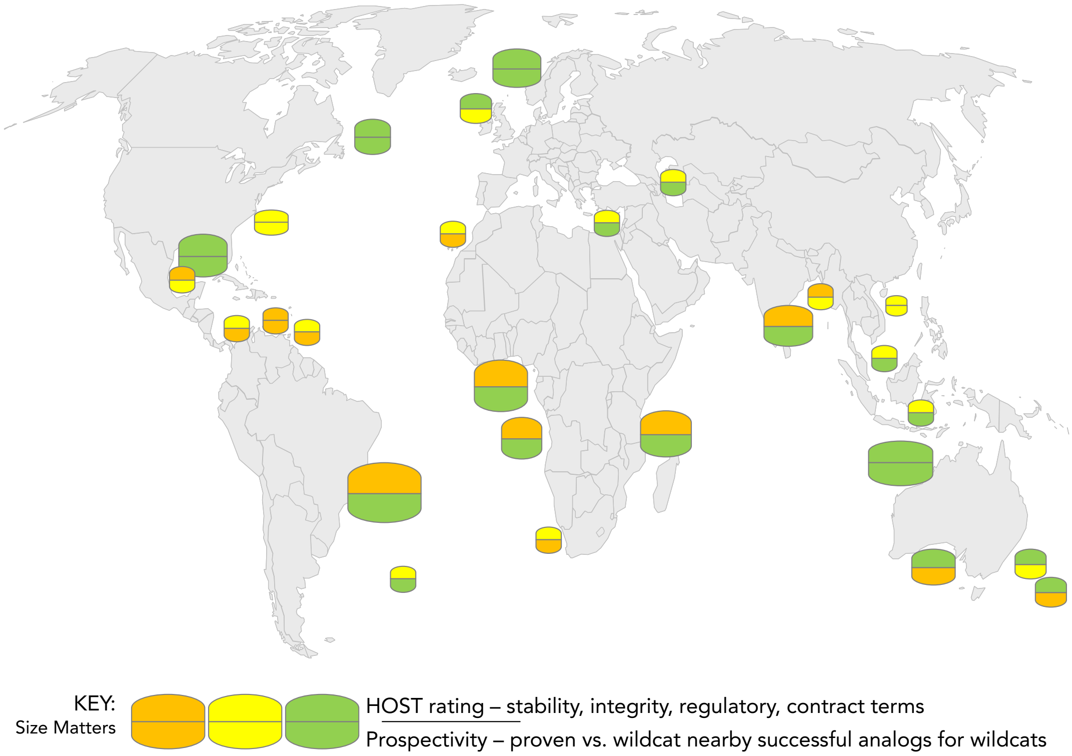
Anadarko embarked on a deepwater exploration campaign off Mozambique to prove the existence of a world-class gas basin off the coast of East Africa even before terms for commercial development were resolved with the government. Subsequent exploration led by super-majors Eni, BG, and Statoil (with ExxonMobil) have proven the Rovuma basin to be one of the most important natural gas sources in the world, extending north into Tanzanian waters, in spite of final exploitation contract terms not being resolved.

The map in Figure 6-3 highlights exploration "hot zones" around the globe. The size of the bubbles on the map indicates the significance of the basin while the color-coding of the upper and lower halves indicate two aspects of attractiveness. The upper half indicates the business environment for international companies considering exploration ventures in the region. The most stable regions/countries with the most business-friendly environment are coloured green, while regions without long-term stability or proven business environments are graded "amber". The lower half colour scheme is green where discoveries have proven up the presence of hydrocarbons in commercial quantities.

One of the most recently opened areas is offshore Myanmar. The 2013 round was successful in attracting strong international interest despite long-held concerns on the country's political openness. BG, Chevron, Eni, Reliance (India), Shell, Statoil, Total and Woodside were all granted blocks in the 2013 licensing round. Woodside just completed negotiation of its PSCs with Myanmar's Ministry of Energy in March 2015, making it holder of exploration rights over the largest acreage in the country. Smaller players, like the UK's Ophir, were attracted into the licensing round by "multiple mapped prospects of world-class potential".

Some of the biggest E&P companies in the world (including BP, Chevron, and Statoil) are making significant investments in the remote deep and ultra-deep frontiers off South Australia and New Zealand. The proximity of T&T to energy-hungry markets in North America and Europe should allow T&T to establish attractive exploration opportunities in comparison to such remote targets.

Figure 6-3 World Deepwater "Hot Zones"



The companies embarking on exploration of T&T's deepwater frontier (BHP, BP, Repsol and BG) are considered well-established deepwater players in the global E&P industry. However, to broaden the search for benchmark countries the recent activities of two other players with quite distinct characteristics provide an alternative perspective on the opportunity to explore off T&T: one is a well-established NOC and the other is a visionary independent. The map in Figure 6-4 shows the global deepwater exploration footprint of Statoil and Noble Energy.

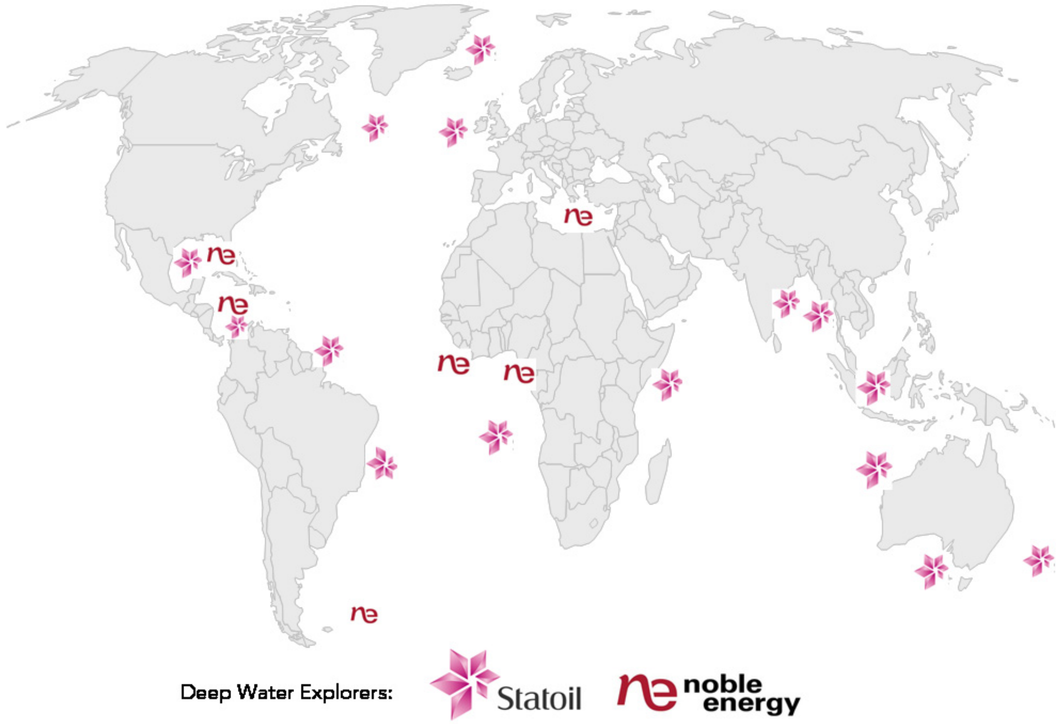
Statoil invests a great amount in deep waters offshore Norway. However, in the past decade its international exploration has also proven very successful. In addition to confidence in its ability to take on the development and application of cutting-edge production technologies, Statoil is also pushing its explorers into many promising deepwater basins around the globe from offshore Greenland in the north (Arctic) to the harsh metocean conditions off the South Island of New Zealand (close to Antarctic waters).

- Statoil, largely through its acquisition of Norsk Hydro, has established a strong presence in the deep waters of the US Gulf of Mexico where production enjoys convenient pipeline access to the world's largest energy market.
- It has established production in deep waters off Brazil at Peregrino and continues to explore in deep waters.
- Statoil also locked in exploration opportunities off Suriname and Colombia covering key prospecting locations along the east and north of South America.
- Across the South Atlantic, it is well positioned in Angola. According to its 2014 annual report, the Angolan continental shelf is the largest contributor to Statoil's oil production

outside Norway. Statoil also participates in Chevron's huge Agbami oil field in deep waters off Nigeria.

- Statoil also has seven discoveries offshore Tanzania in deep water Block 2 with ExxonMobil with expectations for 20 Tcf of reserves. Its exploration efforts off Mozambique, however, have not been successful.
- Acquisition of a 30% interest in BP's 24,000 km^2 license in the Great Australian Bight off South Australia has provided access to a significant opportunity that is planned for drilling by 2017. Statoil also has taken a 100% interest in a 13,700 km^2 exploration license in the well-established Carnarvon basin off the Northwest Australian coast.
- Statoil holds a 100% stake in almost 12,000 km^2 of acreage in waters 1000-2000 m deep northwest of New Zealand's North Island and is participating with Chevron in a very large deepwater license off the east coast of the South Island.

Figure 6-4 Statoil and Noble Energy Deepwater Exploration/Development Locations



Noble Energy (Noble) is a relatively small Texan company that has had a significant impact on the E&P industry. Noble is not so well funded that it can tackle the technology challenges that Statoil can embrace, but Noble has been and is exploring where others have not ventured.

- Like Statoil, Noble continues exploring for and developing reserves in the US Gulf of Mexico.
- Noble drilled an exploration well on a huge target in Nicaraguan waters in 2013 that was dry. However, that result has not stopped Repsol and Petrobras from making another attempt in deep waters north of Colombia.

- Far south off the east coast of South America, Noble has taken positions off the Falkland Islands.
- Across the South Atlantic, Noble is operating in Equatorial Guinea and exploring off Cameroon and Sierra Leone.
- In the eastern Mediterranean, Noble has discovered gas fields (Tamar, Leviathan, and Aphrodite) that are estimated to hold over 40 Tcf of reserves.

Although these two companies have distinctly different economic foundations, technical capabilities, work forces, and exploration styles, their areas of activity provide guidance to the selection of benchmark countries competing with T&T for exploration and development funds.

6.3.3 Mature Fields

T&T's shallow-water basins have been in production for decades and have entered a mature phase of development. Mature fields account for over 70% of global production. With average recovery factors of 70% for gas and 35% for oil, increasing recovery could add years of production to the global hydrocarbon supply. As production costs from mature fields increase, operators are increasingly applying enhanced recovery techniques, reservoir stimulation and targeted resource acquisition in order to maintain and extend the production from mature assets.

As the economic operating margin of maturing fields declines, major companies often relinquish fields to mid-size independent oil companies with lower overhead costs. Recent examples include the sale to Apache of BP's Forties field (in the UK North Sea) in 2003 and North America and Egypt mature plays in 2010, although more recently Apache announced its exit from UK as part of a global strategy to focus on North America. Talisman Energy has also developed a proven track record of growing production and extending the life of mature fields in Malaysia and in the UK. Hess developed the same competence targeting Egypt and Indonesia. Developing a dedicated mature fields policy is high on the agenda of major oil and gas producing countries.

Brazil has built a dedicated mature fields policy for small players which was implemented during the 2013 annual licensing round by offering blocks in mature basins and inactive areas with marginal accumulations. These rounds are exclusive to small and medium-sized local players and are also part of a broader government strategy to promote local content in the industry.

In Mexico, Pemex has signed a range of collaboration agreements since Mexico voted last year to allow private participation in its oil sector for the first time in 75 years. In late 2014, Pemex and Chevron signed an agreement to explore opportunities including deepwater, heavy oil and mature fields. Similar deals were also signed with ExxonMobil, BHP Billiton, Canada's Pacific Rubiales and India's ONGC.

6.3.4 Incumbents' Investment Behavior

The areas of investment and production by T&T's current oil and gas producers, namely BG, bpTT, BHP, EOG and Repsol, are summarised in Table 6-4. These countries are competing directly for investment with T&T and should be represented among the benchmark countries selected for analysis of T&T's competitive position. Appendix C contains a summary of each company's investments, reserves and production.

Table 6-4 T&T Upstream Incumbents' Worldwide Developments

Company	Investment	Production	Comments
BP	USA, Asia (Indonesia, India), Africa (Egypt, Angola), UK, South America (T&T), Canada, Australia, rest of Europe (Azerbaijan), Middle East	Angola, Azerbaijan, GOM, Egypt/North Africa, Asia Pacific, UK/North Sea, T&T, Alaska, Middle East, USA	Deepwater exploration: Angola (core), Australia (frontier), Brazil (core, frontier) Canada (frontier), GOM (near-field, core), Morocco (frontier)
BG	Australia, Brazil, UK, Egypt, Norway, T&T, Tanzania, Kazakhstan, Thailand, USA	Egypt, UK, Kazakhstan, T&T, USA, Thailand, Brazil, Tunisia, Bolivia, Australia, India, Norway	Recognised expertise in sour gas, HPHT, deepwater and unconventional gas
EOG	USA, Canada, T&T	USA, T&T, Canada	
BHP	USA, Australia, Algeria, UK	USA, Australia, Algeria, Pakistan, T&T, UK	25% of gas production (412 MMcf/d) came from deepwater in 2014 / GOM
Repsol	USA, Brazil, Venezuela, Peru, Libya, Algeria, T&T, Bolivia, Russia	T&T, Venezuela, Africa, Peru, North America, Asia, Europe, Argentina	Deepwater activity: Brazil, GOM

6.3.5 Selected Countries

The following eight countries have been selected to benchmark T&T's international competitive position to secure funds for further development of the oil and gas industry:

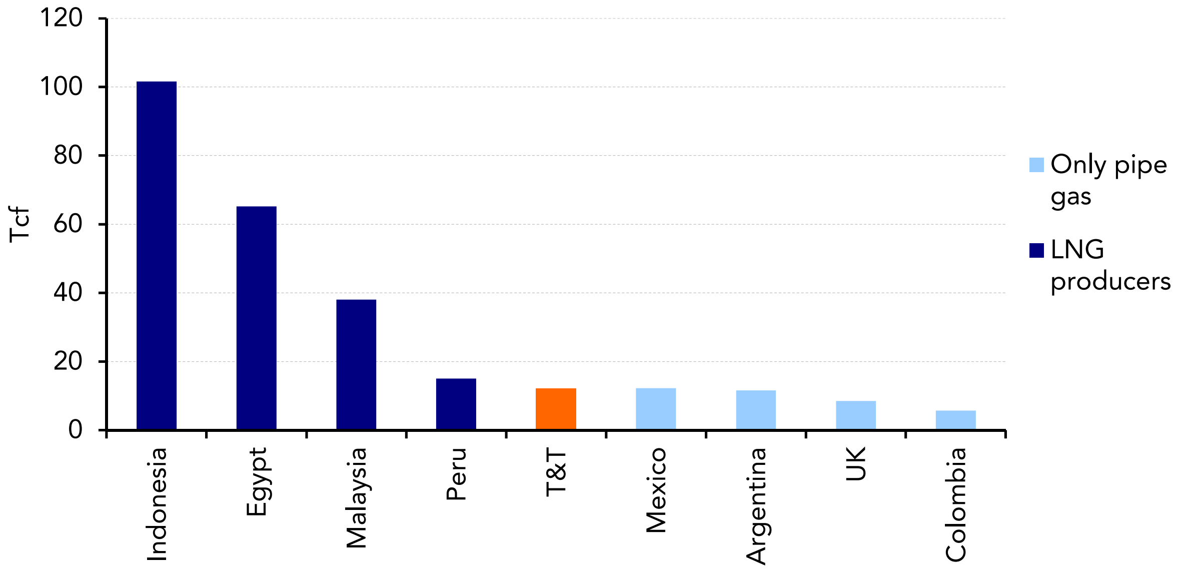
Table 6-5 Comparison of Selected Countries with T&T

	Production Characteristics	Latin America	LNG Producer	Deepwater Exploration	Mature Fields	Incumbent Interest
Indonesia	•		•	•	•	
Egypt	•		•	•	•	•
Malaysia	•		•	•	•	
Peru		•	•			•
Mexico	•	•		•	•	•
Argentina	•	•		•		
UK	•				•	•
Colombia		•		•		•

6.4 GAS RESERVES COMPETITIVE POSITION

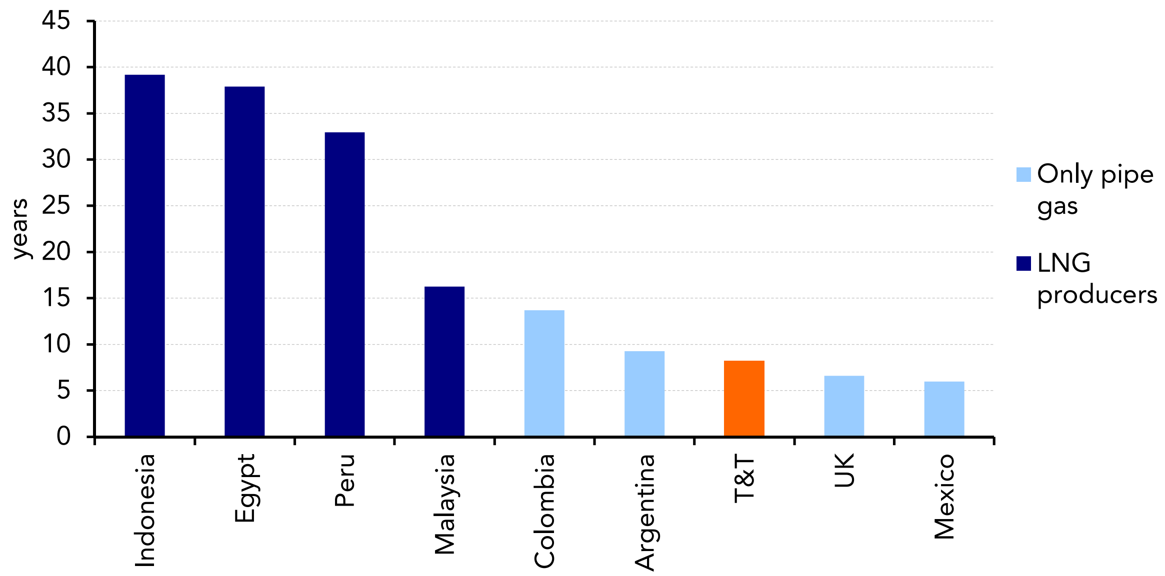
T&T differs from its LNG producing peers in our benchmark group in terms of gas reserves and reserves to production (R/P) ratios. The gas reserves of the benchmark group are presented in Figure 6-5. T&T has the smallest reserves base of any LNG producing country in the benchmark group and with the exception of Peru is the smallest by a considerable margin.

Figure 6-5 Proven Gas Reserves for Benchmark Countries (as of the end of 2014)
(source: BP Statistical Review of World Energy 2015)



The relatively low reserves base is reflected in the R/P ratio presented in Figure 6-6.

Figure 6-6 R/P Ratio for Benchmark Countries (as of the end of 2014)
(source: BP Statistical Review of World Energy 2015)



T&T has an R/P ratio of only 8.2 years based on 2014 reserves and production figures. This contrasts with all the other LNG producing countries in the peer group which have ratios between 15 and 40 years. In this respect, T&T is similar to countries supplying a purely domestic gas market (Argentina, UK and Mexico).

6.5 GAS MARKET ACCESSIBILITY

Gas market access is a key consideration for oil and gas companies considering investment in a country as it is critical to monetising their resources. A gas market that is largely accessible, transparent and with reasonable pricing will encourage investment, while the absence of these characteristics could be seen as a fatal flaw. In this section, we review T&T's competitive position with regards to the price gas developers can achieve and the ease of capture of a gas sale from a regulatory (access to infrastructure, access to market) perspective.

Figure 6-7 Estimated Gas Pricing to Upstream in Benchmark Countries (2013)

(source: various)

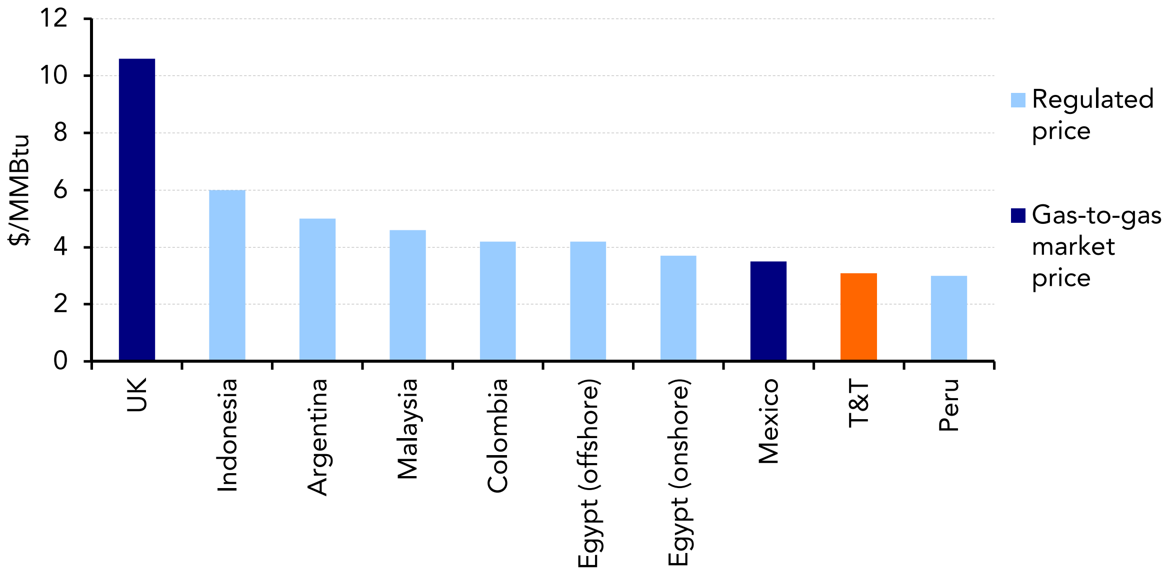


Figure 6-7 shows the estimated average price that upstream gas producers achieved in each of the benchmark markets in 2013. The benchmark group price range extended from more than $10/MMBtu to less than $3/MMBtu, with T&T lying almost at the bottom of this range. If the two countries that have implemented transparent gas-to-gas markets (National Balancing Point (NBP) price for UK gas producers and Henry Hub (HH)-related price for Mexican gas producers) are removed from the comparison and only regulated prices are compared, then the price range is reduced to between $6/MMBtu and $3/MMBtu, but T&T's position near the bottom of the range remains unchanged.

In comparison with the benchmark countries, T&T offers a relatively unattractive gas price to upstream producers.

6.5.1 Enhancing Gas Market Accessibility while Reforming

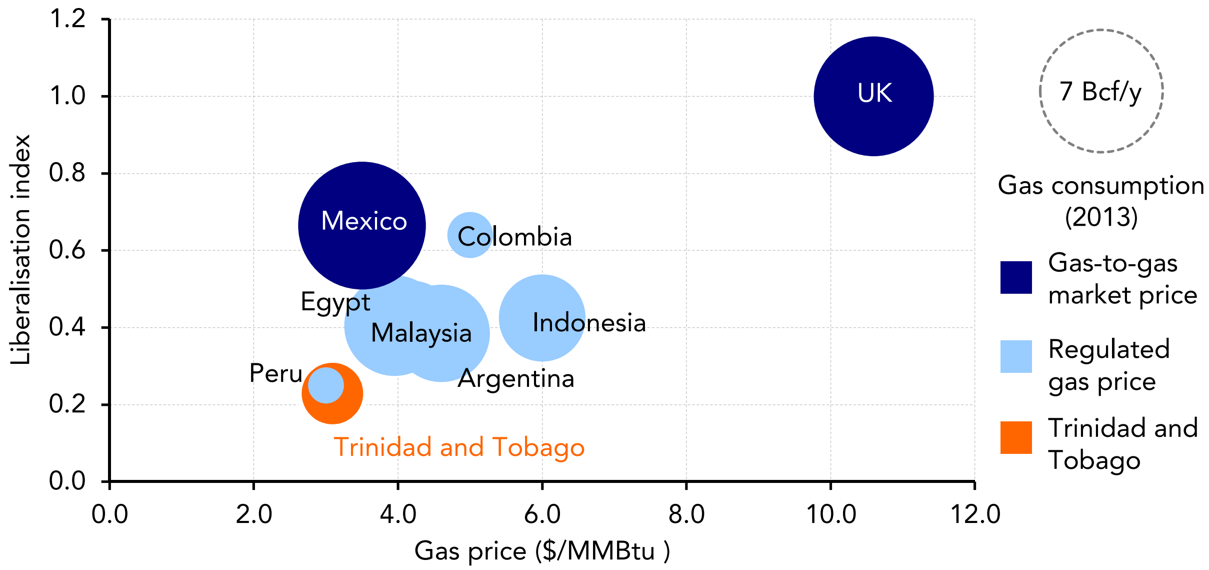
In addition to price, a key consideration for potential investors will be the ease with which their production can access the gas market in terms of both infrastructure and regulation.

Figure 6-8 below provides a view on where each country sits relative to its peers in terms of gas price achievable in the country and its gas market liberalisation status or gas market accessibility. For this later indicator, we have developed a methodology to rank each country following a "liberalisation index", based on assessing for each country two main criteria:

- First, the level of competition in the market, ranked from a pure liquid market down to a private monopoly market, with oligopoly and state monopoly markets in between;
- Second, the transparency of the gas prices in the relevant market. This assessment is based on the existence of an open market, or regulated prices down to private negotiation to establish the gas price.

We subsequently applied the market share that corresponded to each criterion which provided us with the country ranking shown the vertical axis of Figure 6-8 below.

Figure 6-8 Relative Market Attractiveness to Producers in Benchmark Countries (2013)



The UK stands out from the benchmark group. It has a liquid market, enjoying high demand with associated highly developed gas infrastructure. In addition the NBP average price was high in 2013, making the UK the benchmark group leader by far.

The high degree of state participation in the gas value chain in almost all benchmark countries results in a liberalisation index well below the UK for the rest of the benchmark group. In Colombia, which took the path of liberalisation more than a decade ago, prices are still regulated and access to infrastructure is restricted. Nonetheless, the majority of the benchmark countries are making efforts to improve gas market accessibility and pricing as well as improving infrastructure access, for example via partnership with investors to develop new infrastructure under State guarantee of a certain level of offtake.

Compared to the peer group T&T lags the competition in both average gas price and gas market accessibility.

6.6 FISCAL REGIME ATTRACTIVENESS

The following comparison of fiscal terms in each of the benchmark countries is based on public domain information and Poten's business intelligence regarding the main contractual and licensing terms.

In the early years of industry development, T&T awarded Production Licenses to operators under a tax – royalty structure. More recently acreage has been awarded under PSCs, with the terms awarded varying from year to year according to GORTT policy. The following analysis addresses both structures, however all future awards are expected to be under a PSC structure.

Details of some of the competitiveness initiatives put in place in the benchmark countries are provided in Appendix E.

Considering the extremely limited information we received regarding the matrix of production levels applied in T&T's PSCs, in particular the ones regarding deepwater developments, we were unable to perform a detailed comparison of existing matrices in other countries fiscal regime.

6.6.1 Government Take

A fundamental comparison among benchmark countries is the share of revenues that the investor will keep to cover costs and to provide for a return, compared to that taken by the host government. Figure 6-9 below provides the comparison of the government take of each country.

Figure 6-9 Range of "Government Take" in Benchmark Countries

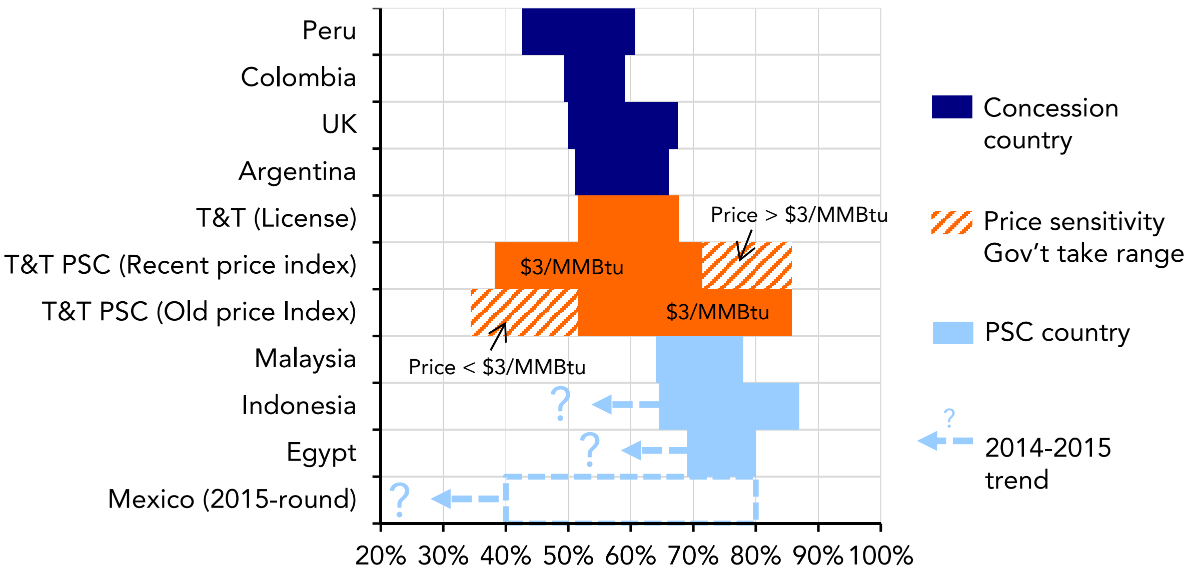


Figure 6-9 provides a high level assessment of current government take in the benchmark group. These countries have been split in two categories: those applying a concession license regime and the others applying a PSC regime. T&T has both concession licenses and PSCs and so both are represented in Figure 6-9. A further delineation is made between early PSC (1996-2005) with terms linked to what are now unrealistically low gas prices ranges and more recent PSCs together with those without price indexing which are robust to market shifts in gas price in the last 5-10 years.. The PSCs use a matrix of production levels and gas prices to determine the share of profit gas retained by the government. PSCs that were signed 1996-2005 have profit gas matrices ranging from \$1/Mcf to an upper limit of \$2 to \$3/Mcf, while more recent PSCs provide profit gas matrices ranging from \$3/Mcf to \$7/Mcf. In cases where the PSC terms are heavily geared to gas prices, the older matrices default to the highest government profit gas share under current gas prices of \$3/Mcf. Newer PSCs with current pricing bands and older PSCs with a relatively low linkage between gas price and profit gas allocation are more robust to the gas price increases over the last 5-10 years.

Figure 6-9 demonstrates that PSCs in T&T which are robust to recent changes in gas pricing are competitive with the benchmark group, and at \$3/MMBtu gas prices span the range of competing concession terms and yield lower government take than benchmark PSC regimes. However, older, price-sensitive PSC terms are significantly less competitive.

PSCs are perceived as providing the host state with a greater share of production than a concession license. This general rule is confirmed by our benchmark group, as depicted in Figure 6-9 above where Malaysia, Indonesia and Egypt enjoy higher government take (from low 60% to over 85%) than Peru, Colombia, UK and Argentina (usually around 50%). Mexico is currently opening its acreage to foreign investment for the first time in 76 years. The terms of the contracts to be introduced are not yet known (and subject to bidders offer), and therefore should be further assessed when they become available. T&T PSC terms span the range covered by both PSC and concession license terms in the benchmark group.

Finally, T&T's previously implemented license terms would be reasonably attractive if applied to new acreage, falling in the lower half of the government take range.

Benchmark peer countries are quickly adapting to the new oil price environment and competition for investment funds. Figure 6-9 above already includes the new UK fiscal package announced on 20th March 2015 which aimed at enhancing production in that mature basin. Mexico is also adapting the terms of the first set of blocks released (shallow waters) following industry feedback on the previously proposed terms and Egypt has recently obtained significant development proposals from its incumbents (BP, BG and Eni).

6.6.2 Cost Recovery as a Differentiator

The speed of cost recovery allowed under a fiscal regime will impact both economic performance of an investment and the perceived risk of investment. Cost recovery mechanisms and rates differ between PSC and tax-royalty concession regimes. PSCs often cap the proportion of a year's production revenue which can be applied to cost recovery whereas tax-royalty concession regimes generally do not. Both regimes set a constraint on how quickly the cost of a particular expenditure item can be recovered, through a depreciation schedule under a tax-royalty regime and a cost recovery schedule under a PSC.

In general PSCs offer more rapid recovery of cost than a tax-royalty concession and, being bid as part of the petroleum license, are more easily adjusted by a host government than the tax-royalty terms which are often set in tax legislation.

Figure 6-10 Maximum Cost Recovery in Percentage of Annual Revenues (PSC)

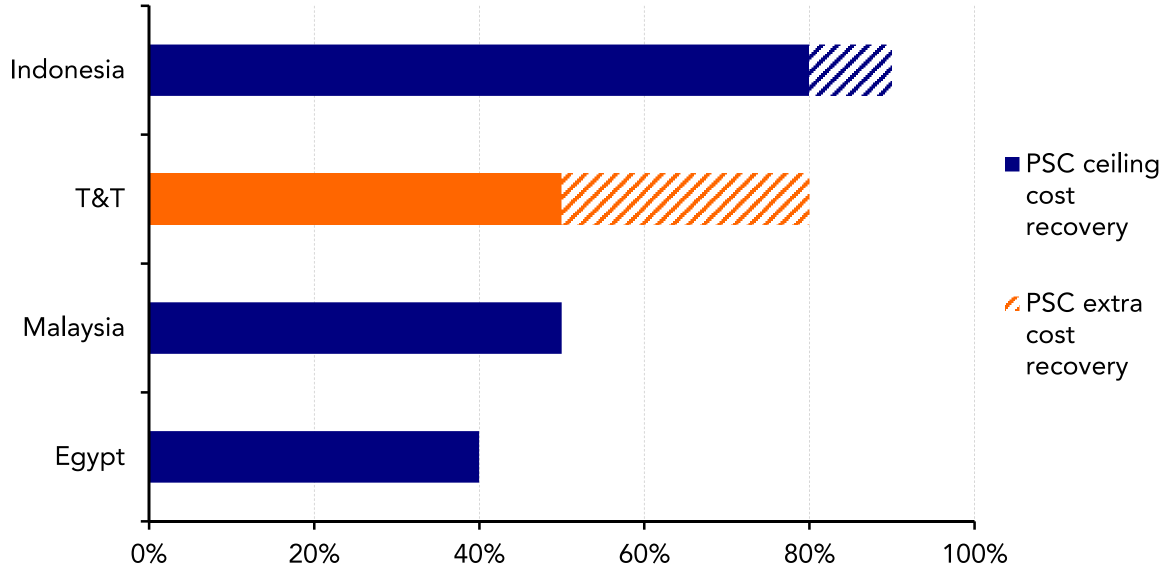


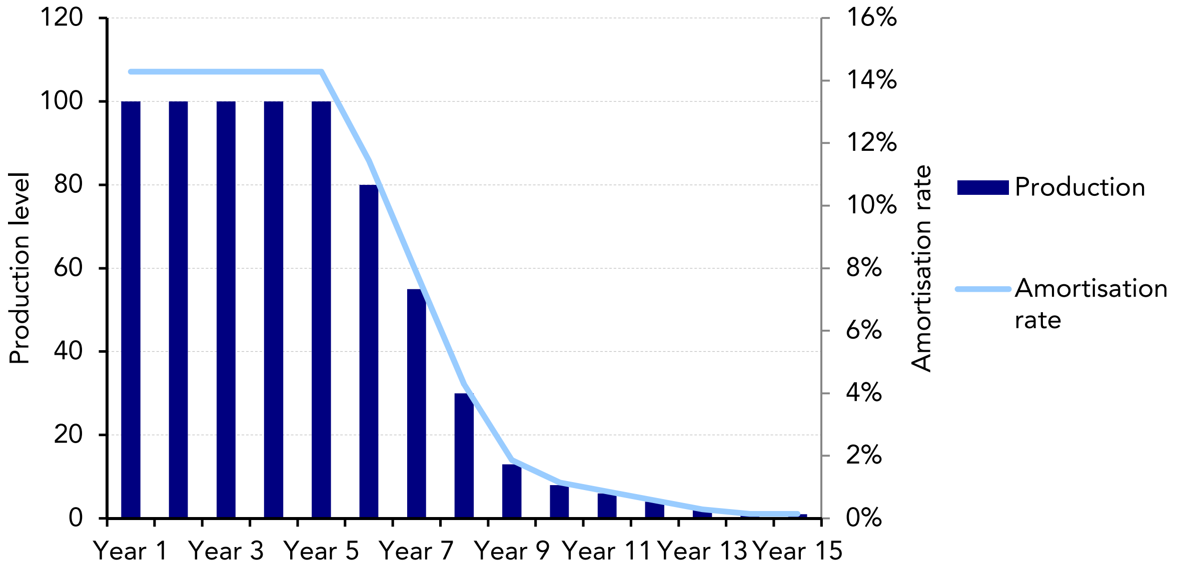
Figure 6-10 provides a comparison of the PSC revenue ceiling dedicated to cost recovery in our pool of countries. T&T sits in the mid to high range of this comparison at 50%-80%, compared with Egypt at 40%, Malaysia at 50% and Indonesia at 80% of annual revenue.

The actual amount allocated to cost recovery will also be limited by the recoverable cost pool within the PSC ring fence. If the amount of cost available for recovery on the basis of the annual amortisation schedule is less than the ceiling (80% of revenues for Indonesia) then only the costs available for recovery can be used to claim a cost oil allocation. Recent T&T PSCs awardee in 2011-12 allow capital cost recovery as it is expensed and thus the only limit on cost recovery is the cap of production revenue. Earlier PSCs (1996-2005) specify allocation of costs to the cost recovery pool over a period of up to 4 years (40%, 20%, 20%, 20%).

A tax-royalty concession typically allows the entire production revenue to be used to offset costs, the only cap being the annual maximum amount of cost being amortised. In the list of countries offering concession analysed, the capital cost depreciation schedule is 5 years (20%) for Colombia and Peru, and 4 years for the UK (25%).

Argentina is proposing a less favourable “Unit of Production” (UoP) or R-Factor mechanism which spreads amortisation of capital costs over the production plateau period. Under a UoP amortisation scheme, the annual amortisation rate is defined as the annual production for that year divided by the cumulative production over the life of the field. In the example showed in Figure 6-11, the cumulative production of the fields is set at 700 units and the plateau is set at 100 units per year, which gives an amortisation rate of ~14% during the plateau years, well below the 25% (or 20%) expected under either the other concession licence or PSC terms.

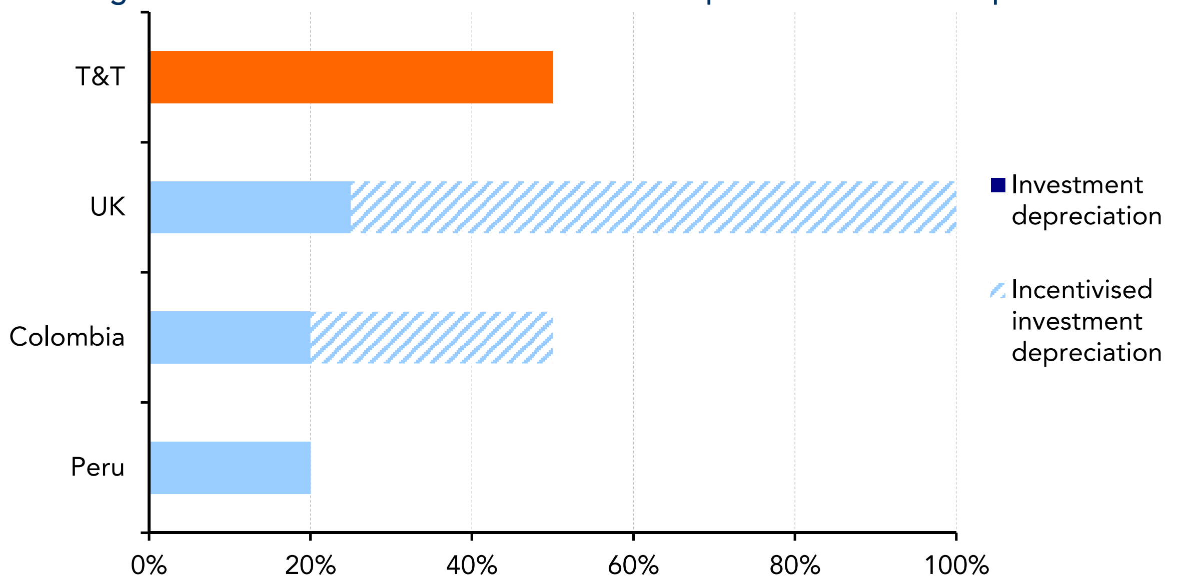
Figure 6-11 Schematic of "Unit of Production" Amortisation Rate



The production licenses awarded in earlier years by T&T, but which are no longer offered, provided a more attractive mechanism for cost recovery than most tax – royalty schemes. Depreciation for the 1st year was set at 50%, 30% for the 2nd year and finally 20% for the 3rd and final year of amortisation. Figure 6-12 ranks T&T first out of the countries offering concession license from the benchmark group, when focusing on the 1st year rate of investment depreciation.

Depreciation rates may also be adjusted as an incentive for specific investment classes. For example, the UK incentivises some fields with a 100% amortisation in the year of expenditures to encourage investment in brownfield developments.

Figure 6-12 Concession License 1st Year Depreciation Rate Comparison



6.7 EASE OF DOING BUSINESS

Political and broader country risks are a critical part of the assessment of a potential investment in a country and a review of the ease of doing business in the countries of our benchmark pool provides another measure of comparison. Three independent ratings have been reviewed to provide a high-level comparison of each country's relative position in the benchmark group.

T&T compares well under the ease of doing business criteria for its oil and gas industry, second only to the UK. Fraser Institute data shows T&T is attractive in terms of country/political risks for companies wishing to invest in oil and gas sector, nonetheless T&T ranks lower in the World Bank's "ease of doing business" ranking, which recommends improvement on the enforcement of contracts. Indonesia, Egypt and Argentina consistently rank low in this comparison. However, these three particular countries have proved successful in raising their investment profile recently.

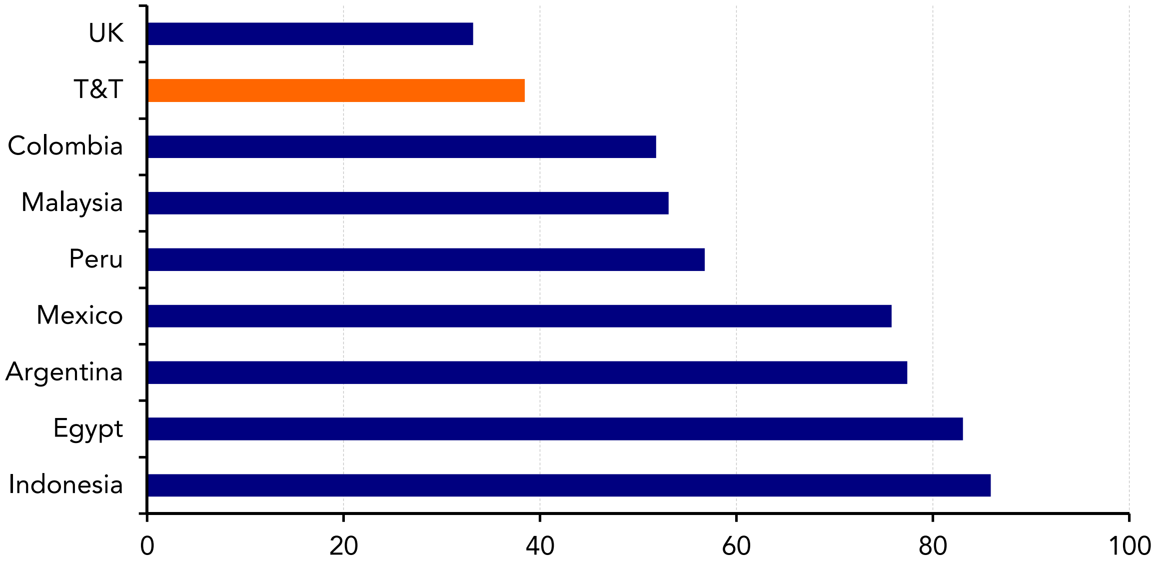
6.7.1 Fraser Institute Global Petroleum Survey

The Fraser Institute conducted surveys on 156 jurisdictions (710 respondents) regarding barriers to investment in oil and gas exploration and production facilities. Each jurisdiction was assigned a score on the result of 16 questions that affect oil and gas investment decisions. The questions asked for scoring covered the following areas:

- Fiscal terms, taxation
- Environmental regulation
- Regulatory enforcement
- Cost of regulatory compliance
- Protected areas
- Trade barriers
- Labour regulations and employment agreements
- Quality of infrastructure
- Quality of geological database
- Labour availability and skills
- Disputed land claim
- Political stability
- Security
- Regulatory duplication and inconsistencies
- Legal system

The final country score is based on the proportion of negative responses a country (jurisdiction) received with regard to each question. The greater the portion of negative responses for a country, the greater were its perceived investment barriers, and, therefore, the lower its ranking (maximum score of 100 was reached by Venezuela making it the worst place to attract E&P investment in 2014). The Fraser Institute categorises the results per group of countries on the basis of their reserves. Figure 6-13 shows the results for our benchmark group of countries without distinction for size of reserves.

Figure 6-13 Fraser Institute – Barriers to Investment in Benchmark Countries (2014)



In our benchmark group, three distinct groups emerge:

- The UK and T&T have relatively low barriers for oil and gas investment. They were ranked as 31st and 44th among the 156 countries/regions. Both stand as much more attractive than the other countries in our benchmark group.
- Colombia, Malaysia and Peru ranked as 65th, 70th, and 78th respectively. Regulations and approval process/time were issues quoted for Colombia and Peru, while tax issues were mentioned as an issue in Malaysia.
- Mexico was assessed prior to constitutional modifications and was perceived as a difficult place to invest (rank 125th). Argentina was split into six regions for the evaluation purpose, and all the regions ranked between 107th and 134th. Gas pricing structure was highlighted as a major problem in Egypt which ranked 136th. The bottom rank of our benchmark group was held by Indonesia which ranked 145th out of 156.

6.7.2 Credit Ratings

A credit rating from one or more of the major credit rating agencies (Standard & Poor's, Moody's Investors Service, and Fitch Ratings) is one of the most widely used indicators to communicate creditworthiness and credit quality. It provides a benchmark for evaluating the relative credit risk of issuers worldwide.

Figure 6-14 S&P Credit Ratings for Benchmark Countries (2014)

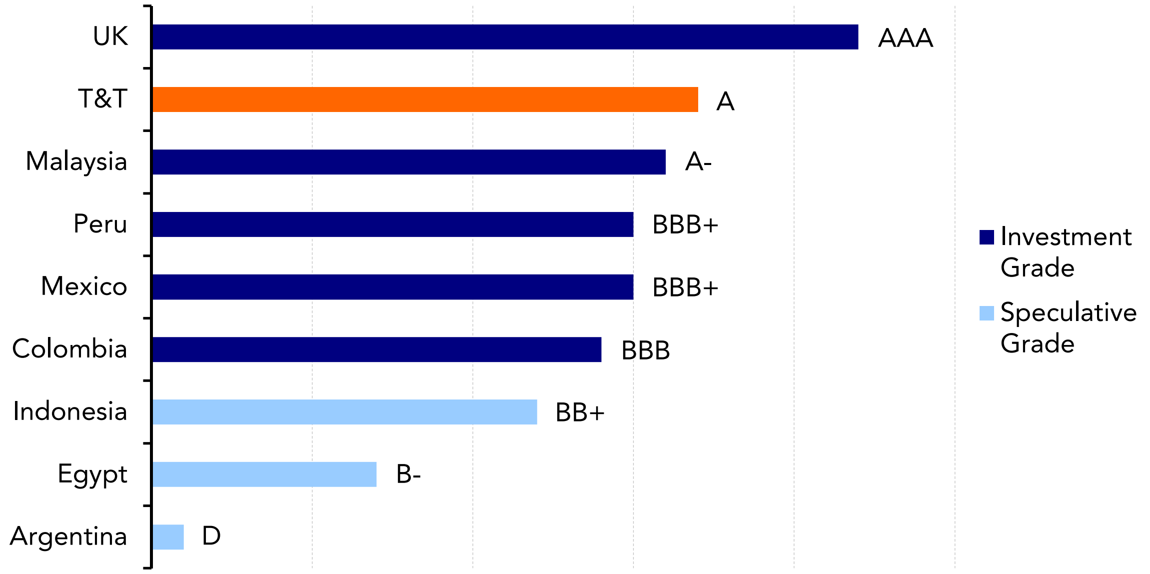


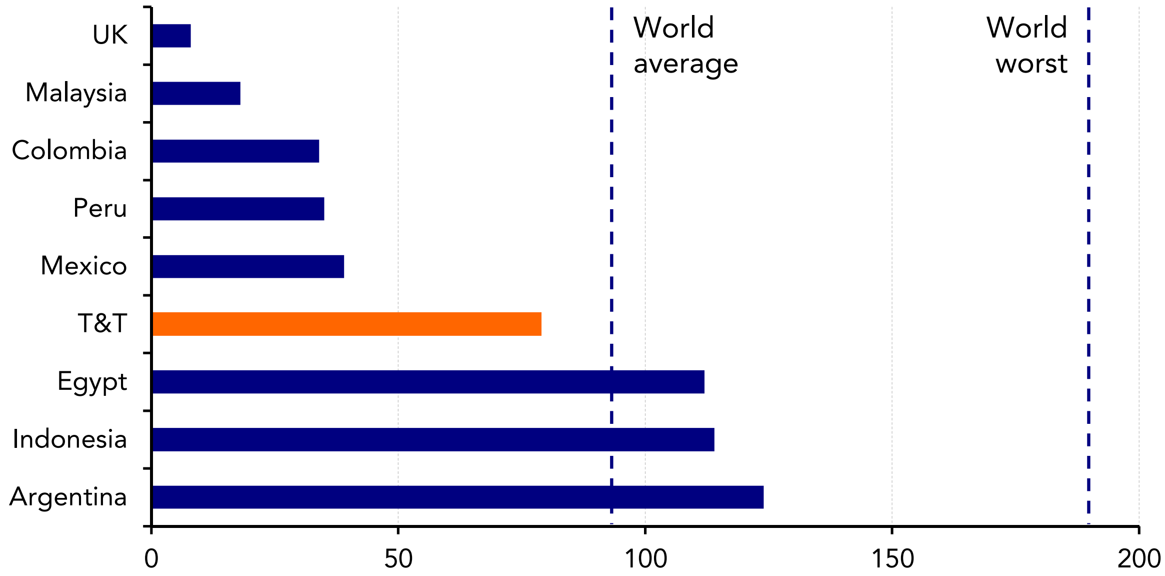
Figure 6-14 ranks the different countries according to S&P ratings. T&T stands as a strong second, behind the top-ranked UK. Three countries, Indonesia, Egypt and Argentina rank as "speculative grade". Argentina has the worst credit rating possible, as the country failed to repay part of its national debt on time.

6.7.3 World Bank "Ease of Doing Business" Ranking

While the Fraser Institute report focuses exclusively on oil and gas sector investments, the World Bank report is more general as it covers the following topics:

- Enforcing contracts
- Trading across borders
- Paying taxes
- Registering property
- Getting credit
- Getting electricity
- Dealing with construction permits
- Starting a business

Figure 6-15 World Bank "Ease of Doing Business" Ranking (2014)



The World Bank's "Ease of Doing Business" index for the benchmark group is shown in Figure 6-15 above. It shows that UK and to a lesser extent Malaysia are easy places to do business, followed by South American countries, namely Colombia, Peru and Mexico, which are as attractive as, for example, France or Japan (both the latter countries also ranking in the 30s). T&T appears as a relatively more difficult place for business, but not as difficult as Egypt, Indonesia and Argentina. According to the World Bank, T&T would need to primarily improve contract enforcement.

6.8 CONCLUSIONS

Based on the four main criteria assessed on the previous sections (gas reserves, gas market accessibility, government take level and ease of doing business ranking) an overall ranking has been developed for the benchmark countries, which is summarised in Table 6-6 below. The table shows two distinctive cases for T&T: the gas price sensitive PSCs and the gas price robust PSCs.

Table 6-6 Overall Ranking by Benchmark Country

COUNTRY	OVERALL RANKING	Ranking per criteria (out of 9):			
		Proven Reserves	Market Accessibility	Gov't Take	Ease of Doing Business
Colombia	#1	5	2	2	3
UK	#2	8	1	3	1
Peru	#3	2	8	1	5
T&T (Price Robust PSC)	#4	7	9	1	2
Indonesia	#5	1	3	7	9
Malaysia	#6	4	6	6	4
Argentina	#7	6	5	4	7
T&T (Price Sensitive PSC)	#8	7	9	5	2
Egypt	#9	3	7	8	8
Mexico	TBC	9	4	TBC	6

T&T's price-robust PSCs with profit splits indexed to current gas prices or without price indexing at all are ranked in fourth place, leading the countries where PSCs were implemented; but still lagging behind countries that have implemented concession licences. However older price-sensitive PSCs linked to gas prices below current levels rank second to last within the benchmark group, highlighting the fact that an incumbent under price-sensitive PSC terms faces a greater hurdle to invest in T&T to sustain production compared to opportunities elsewhere. T&T's production license terms deliver similar economic results to the older price-sensitive PSC terms.

In conclusion, although T&T is a reasonable place to do business, improvements in fiscal terms and gas market accessibility are required to further attract investment, in particular for incumbents under old PSCs and license terms who have to invest to maintain production.

The ranking presented here should be read as a qualitative rather than rigorously quantitative analysis. Some countries with a low ease of doing business score but with substantial gas reserves have managed to attract investment by modifying aspects of their industry sectors such as gas price, government take, license periods and investment allowances.

7.1 RESERVES TERMINOLOGY

The terms Proven, Probable and Possible Reserves are used to describe the incremental volumes added by increasingly optimistic levels of assessment of the commercially recoverable volumes from a reservoir.

- Proven Reserves are those quantities of petroleum, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the proven (1P) quantities actually recovered will equal or exceed the estimate.
- Probable Reserves are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proven Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.
- Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proven plus Probable plus Possible (3P) Reserves, which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

A full description of the SPE reserves terminology and guidelines used in this analysis is described in more detail in Appendix D.

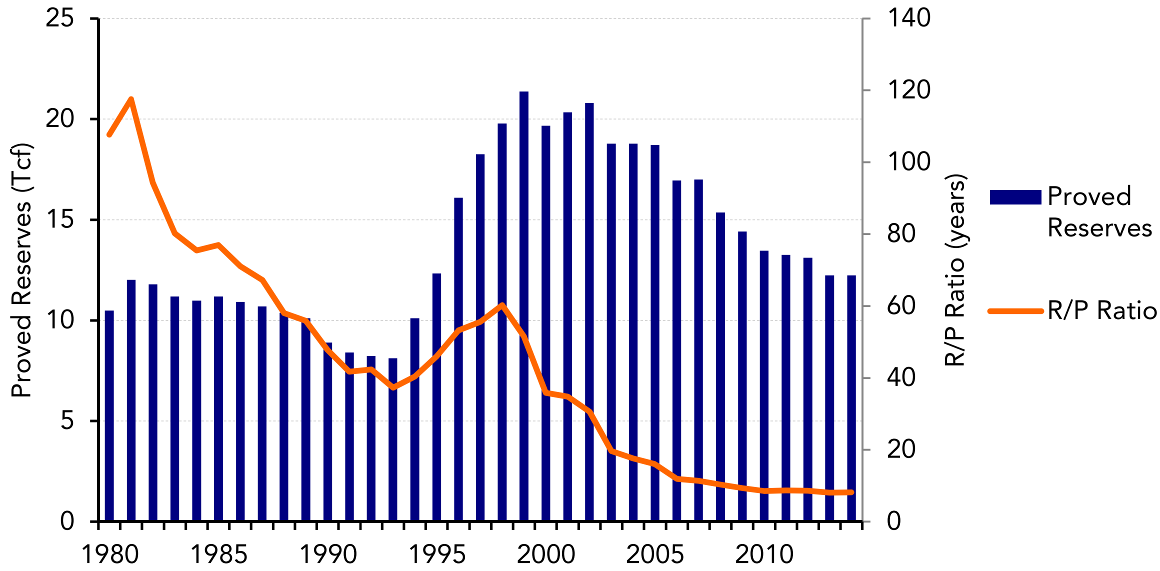
7.2 T&T RESERVES BASE EVOLUTION

The total proven natural gas reserves in T&T have been in decline over the last decade as the rate of reserves additions has failed to keep pace with production. Proven reserves peaked in 2002 at approximately 20.8 Tcf. During 2003 and 2004 there was almost 100% reserves replacement but by 2006 proven reserves had dropped to 17 Tcf. The decline since has fluctuated year on year but by the end of 2013 proven reserves had dropped 41% from the 2002 peak.

Recently the production rate has declined marginally from a peak of 1.58 Tcf in 2010 to 1.47 Tcf in 2013. This has been due to supply curtailments as field deliverability has fallen and not been replaced with sufficient new production capacity to cover planned and unplanned shutdowns on individual fields. Annual demand remains at ~1.62 Tcf (4.27 Bcf/d supply to downstream, assuming 3.5% shrinkage), but customers have been obliged to reduce their consumption as supply has been periodically curtailed or interrupted.

Figure 7-1 T&T Reserves Evolution

(source: BP Statistical Review of World Energy 2015)



The ratio of reserves to production (R/P) provides a measure of the sufficiency of reserves to maintain production over the long term. Based on Ryder Scott data, as of end-2013, proven (1P) R/P ratio was 8.3 years and the Proven + Probable (2P) R/P ratio was 12.1 years (see Figure 7-2). The BP Statistical Review of World Energy gives a proven (1P) R/P ratio of 8.2 years as of the end of 2014 (see **Error! Reference source not found.**).

Considering current demand of ~1.62 Tcf/y, the R/P ratios are as follows:

- Ryder Scott 1P/BP 1P: 7.6 years
- Ryder Scott 2P: 11.0 years

However, due to the natural decline in deliverability of the gas fields as reserves are depleted, gas production will fall below the ~1.62 Tcf/y plateau level significantly earlier than the ~8-11 year durations implied by these ratios, even if such a plateau rate could be achieved.

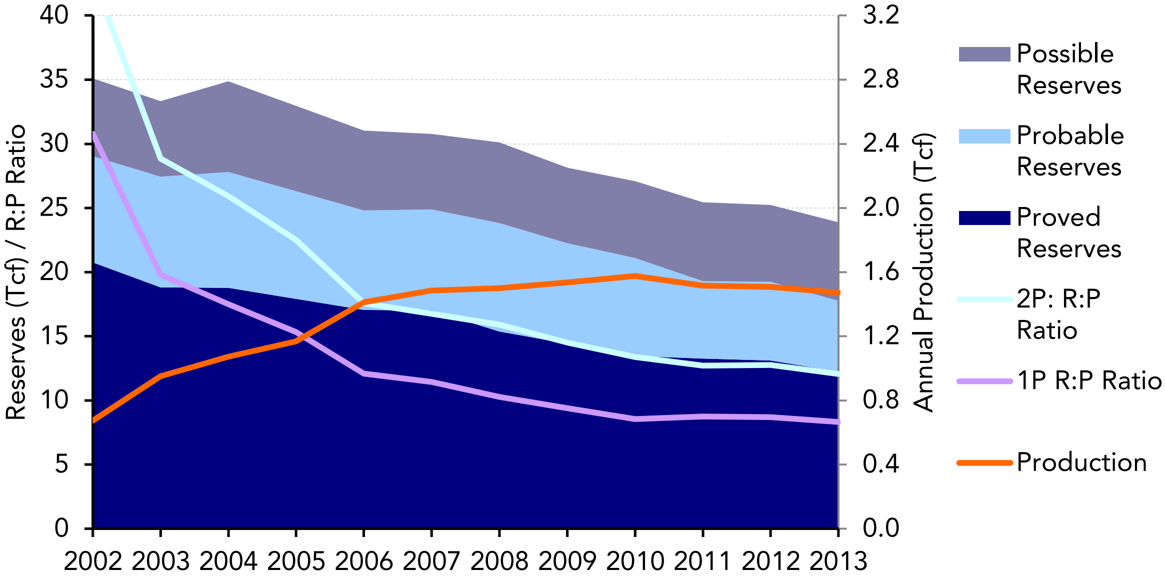
Table 7-1 T&T Gas Reserves Development

(Bcf, source: Ryder Scott)

Year	Proven	Probable	Possible
2000	19,647	7,693	5,468
2001	20,348	8,117	5,857
2002	20,758	8,280	6,062
2003	18,809	8,627	5,890
2004	18,775	9,029	7,066
2005	N/A	N/A	N/A
2006	17,052	7,760	6,225
2007	16,997	7,883	5,888
2008	15,374	8,451	6,266
2009	14,416	7,837	5,893
2010	13,460	7,642	5,995
2011	13,257	6,035	6,158
2012	13,106	6,142	5,987
2013	12,240	5,526	6,116

Figure 7-2 T&T Reserves and Reserves/Production Ratios

(source: Ryder Scott)



The challenge for the industry is therefore two-fold:

- Restoring and maintaining production deliverability from the reserves base to meet the current annual gas demand of ~1.62 Tcf/y; and

- Replacing the produced gas volumes with new reserves from appraisal and exploration activity.

The fast diminishing R/P ratio would indicate that there should be a focus on encouraging exploration activities to prove up new gas reserves from its potential resource base and boost the pace of exploration.

7.2.1 Current Reserves Base

MEEA commissions a reserves report for all national acreage annually; the most recent report by Ryder Scott details reserves and resources as at 31 December 2013. This report provides a comprehensive statement of estimated remaining reserves and prospective resources, risking factors for these volumes and indicative production profiles for each field.

T&T's proven natural gas reserves totalled 12.2 Tcf at end 2013. These reserves consist mainly of non-associated gas and as such the potential production restrictions of gas associated with oil production are limited. The analysis from the most recent Ryder Scott reserves report commissioned by MEEA is shown in Table 7-2 and Table 7-3.

The proven reserves make up 51% of the unrisked reserve distribution, with 23% in the probable category and 26% in the possible category.

As can be seen in Table 7-3 the largest proven gas resources are held by bpTT who hold 55% of the unrisked reserve base, followed by BG with 20% - so three quarters of the country's reserves are in the hands of these two companies. It should be noted that in this table the volumes held by Chevron relate to T&T equity reserves in the cross-border fields with Venezuela, which will not be readily available until a cross-border field development plan is put in place. Without the Chevron reserves the unrisked proven reserves would be ~11 Tcf.

Table 7-2 T&T Unrisked Gross Reserves at December 2013
(Source: Ryder Scott)

Category	Gas (Bcf)	Condensate (bbl)	NGL (bbl)
Proven Reserves	12.240	41,012,953	44.119,615
Probable Reserves	5,526	22,880,305	21,377,993
Possible Reserves	6,116	32,175,419	24,236,007
Total	23,881	96,068,677	89,733,615
Identified Exploration Resources	39,867	112,448,469	188,281,911
Total	63,748	208,517,146	278,015,526

Table 7-3 T&T Unrisked Gas Reserves (Bcf) by Company at December 2013

(Source: Ryder Scott)

Company	Proven	Probable	Possible	Sub-Total	Identified Exploration Resources	Total
bpTT	6,728	2,969	2,881	12,578	5,597	18,175
BG	2,388	1,159	2,099	5,646	8,546	14,191
BHP	526	243	156	924	668	1,592
Chevron	1,186	382	-	1,568	-	1,568
EOG	754	269	342	1,366	2,152	3,518
Centrica	618	498	397	1,512	5,415	6,927
Repsol	41	7	-	48	-	48
Niko	-	-	-	-	8,292	8,292
Open Areas	-	-	240	240	9,198	9,438
Total	12,240	5,526	6,116	23,881	39,867	63,748

While the Proven, Probable and Possible reserves estimates provide an indication of the range of possible recovered volumes, it is often more instructive to consider the mean or most likely reserves figure. This is calculated by applying a risk factor to the Probable and Possible contributions, to reflect the fact that they are less likely to be realized than Proven reserves. Ryder Scott has produced an estimate of risked reserves based on their own risk factors for the different categories (see Table 7-4).

Table 7-4 T&T Risked Gas Reserves at December 2013

(Source: Ryder Scott)

Category	Gas (Bcf)	Condensate (bbl)	NGL (bbl)
Proved	12,240	41,012,953	44,119,615
Probable	3,369	13,964,181	12,288,284
Possible	1,368	7,409,315	5,553,847
Total	16,976	62,386,449	61,961,746
Identified Exploration Resources	6,237[1]	17,710,139	28,135,692
Total	22,213	80,096,588	90,097,438

The average risk factors applied by Ryder Scott are 61% to probable reserves, 22% to possible reserves and 12% to exploration resources. The basis of these risking factors was not included in the Ryder Scott

[1] There appears to be an arithmetic error in Table 2 in the Ryder Scott report which excludes the Niko volumes from the total risked exploration volumes. This error is carried through the Ryder Scott report summary, but is corrected in the table above.

report and therefore Poten is not able to comment upon these risking factors other than to note that they are similar, but not identical to Swanson's rule risking factors (see Appendix D).

7.2.2 Ryder Scott Reserves and Resources

7.2.2.1 Role of Reserves Certifier

A reserves certification is an independent view of gas volumes based on information provided by the operator. The certifier's role is to review the information and development plans provided by the operator and make an assessment of remaining volumes and risks on the basis of the certifier's professional experience and judgment in the context of an internationally accepted reserves classification system. Ryder Scott has applied the widely used 2007 SPE PRMS classification system described in Appendix D. The data provided by operators to Ryder Scott represents a snap shot in time of their development plans which will continue to evolve. The Ryder Scott report provides a statement of reserves as at 31 December 2013. It is dated June 2014 and, given the extensive body of work which went into this report, is likely to be based on operator data generated in late 2013 / early 2014.

The report provides a narrative of the data assessed for each field and prospect that was reviewed, tabulates the P10, P50, P90 remaining volumes and assigns a Probability of Success to exploration prospects. Expected forward production profiles are documented by reserve category. It provides a comprehensive and authoritative reference for assessing the remaining gas volumes in T&T fields. The forward production profiles should, however, be read as an independent assessment of a technically credible scenario, rather than a firm plan for production by the operators. It does not differentiate between firm operator development plans and notional plans yet to be sanctioned for development. The forward profiles therefore provide a view on possible future production that must be read in conjunction with operator plans to provide a balanced picture on likely future gas production.

The following section presents the results of the Ryder Scott report. Subsequent sections contrast the Ryder Scott report with operator plans and provide an opinion on the range of outcomes that should be considered for master planning purposes.

7.2.2.2 Reserves and Prospective Resource Profiles

The Ryder Scott Report presents Proven, Probable and Possible reserves for all discovered fields together with a Risk Factor for each reserves category. Each reserves category in each field is multiplied by the Risk Factor to provide Risked Profiles, the sum of which are presented as a mean production profile for the portfolio. The risk factors presented are similar to the factors presented by Swanson[2] for estimation of mean production from a P10, P50 and P90 distribution and vary slightly between fields. No discussion of the derivation of the risk factors is presented. The graphs below present raw profiles from the Ryder Scott report, an adjustment of the profiles to align with the available gas market in T&T, and a discussion of the interpretation of these results.

[2] See discussion in Appendix D.

Figure 7-3 Ryder Scott Risked Reserves and Prospective Resource Profile

(Source: Ryder Scott)

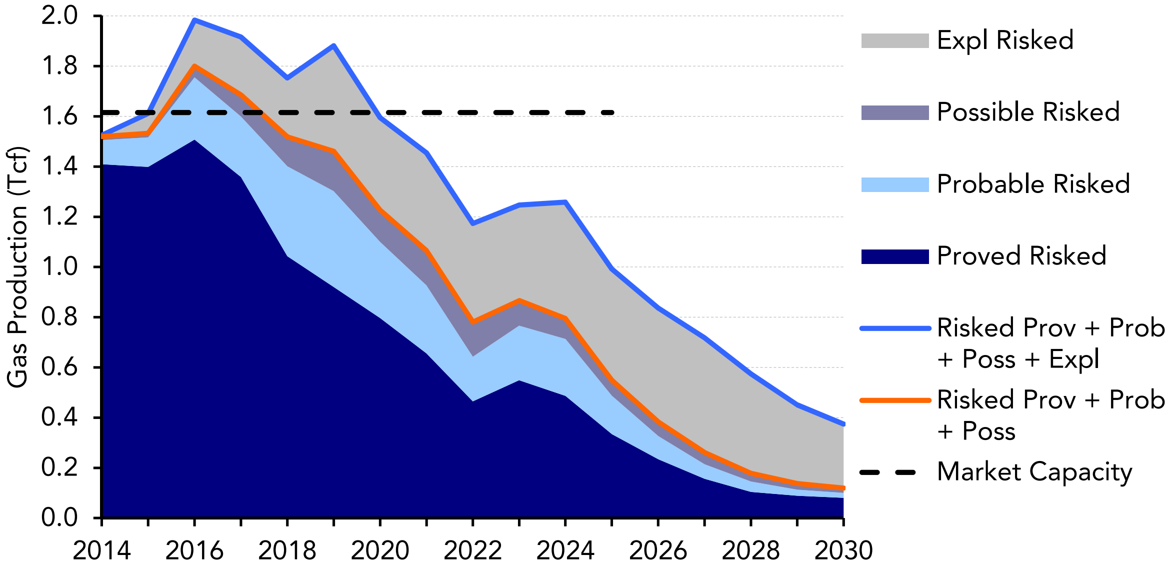


Figure 7-3 plots the risked (expected) gas profile from the Ryder Scott report, showing the contributions from Proven, Probable, Possible and Prospective resource categories from all the fields assessed by Ryder Scott. The technically possible gas production depicted in this figure is unconstrained by market capacity and assumes that all field development plans will be sanctioned by the operators.

Poten has reviewed the historical consumption of gas in T&T through ALNG and NGC and matched this with gas production records provided by MEAA. This data suggests a maximum average demand of 4,268.5 MMcf/d. Supply records indicate a shrinkage of 3.5% between produced gas and consumed volumes which is likely to be due to a combination of offshore facility and compression fuel consumption, liquids drop out in the transmission system and gas accounting assumptions. The 3.5% shrinkage has been maintained in our forward projections, resulting in a maximum offshore production rate of 4,423 MMcf/d or 1.616 Tcf/yr. The impact of constraining production to this level is illustrated in Figure 7-4. By deferring gas production from early years where production potential exceeds demand, the production plateau is extended and the initial rate of decline from plateau is reduced.

Figure 7-4 Ryder Scott Risked Reserves and Prospective Resource Profile Constrained to Market Demand of 1.62 Tcf/y

(source: Ryder Scott)

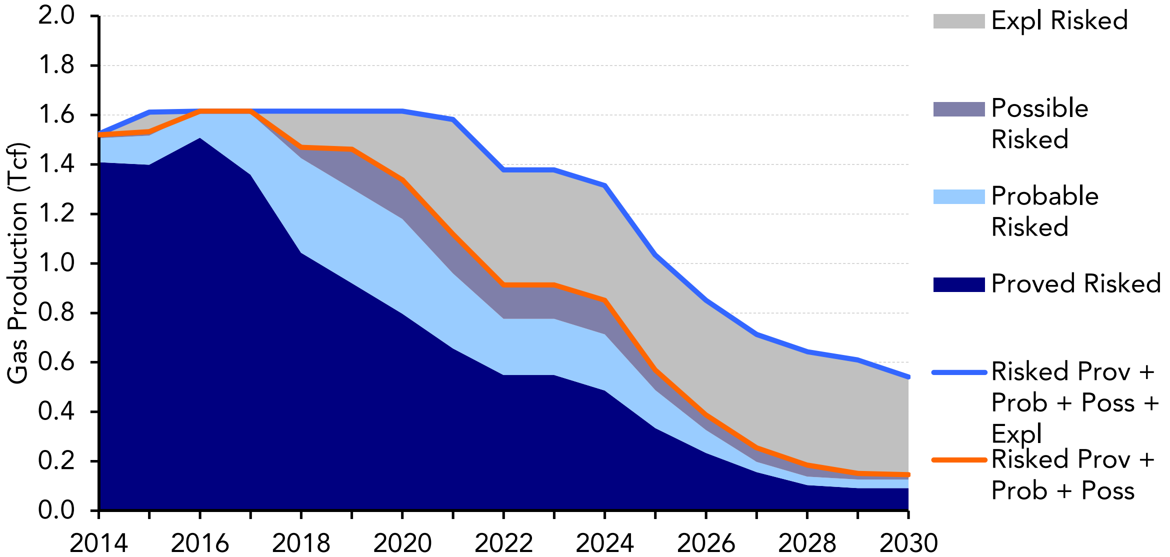
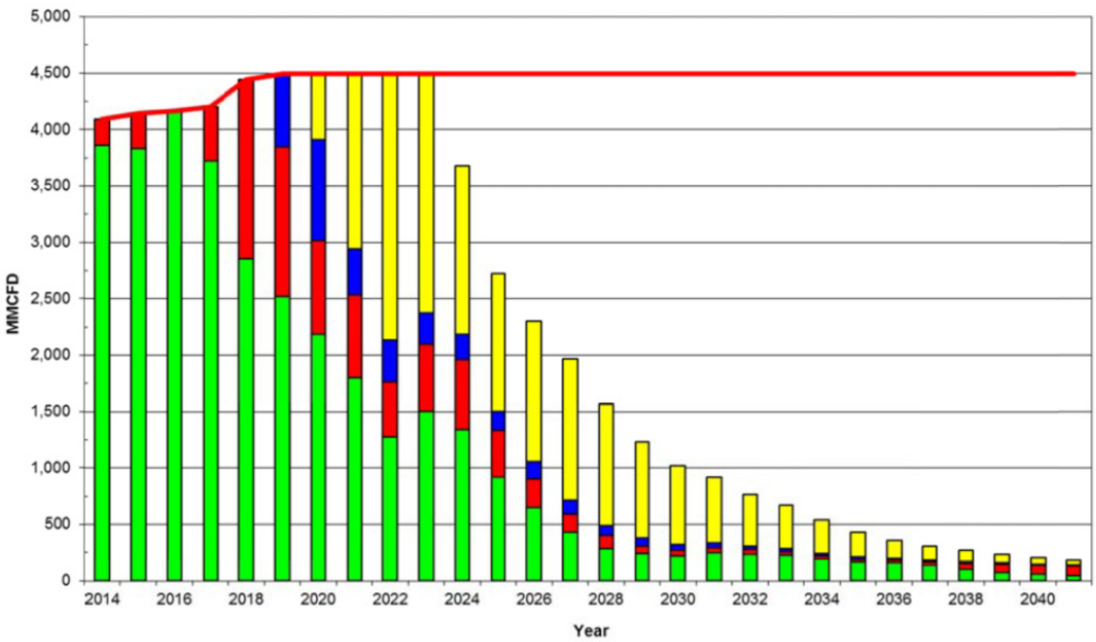


Figure 7-5 Ryder Scott Risked Reserves Gas Forecast versus Market Demand

(source: Ryder Scott)



The impact of these adjustments is illustrated in Figure 7-4, showing that:

- Based on only Proven, Probable and Possible reserves (i.e. discovered resources) gas production will fall below the market demand of 4.42 Bcf/d (1.62 Tcf/y) in late 2018.
- Taking into consideration the expected outcome from the exploration prospects reviewed by Ryder Scott, the production plateau period is extended to late 2020 / early 2021.

Without access to the detailed analysis of individual fields, the market levelling applied here is likely to be a little conservative. A similar exercise is presented in the Ryder Scott report, but for a different level of market demand, the results of which are re-produced in Figure 7-5.

The Ryder Scott market levelling assumes a ramping market demand, but with a similar average to the Poten assumption of 4.4 Bcf/d. The final plateau year from only Proven, Probable and Possible reserves (i.e. discovered resources) is 2019, which aligns with the Poten analysis. When prospective resources are taken into consideration the last plateau year in the Ryder Scott profile is 2023, but to achieve this profile relies on circa 50% of production in 2022 and 2023 from prospective resources. This represents a significant acceleration of prospective resource production from the profiles detailed in the body of the Ryder Scott report which would need to rely upon a high success rate in early exploration wells and a significant increase in exploration activity.

7.2.2.3 Treatment of Prospective Resources

The Ryder Scott report catalogues prospective resource volumes and Probability of Success in some detail. The risked or expected volume from the exploration prospects totals 6,300 Bcf from 151 prospects. The distribution of prospect sizes is illustrated in Figure 7-6 which presents the success case mean recoverable volume (blue columns together with cumulative risked and unrisked portfolio volumes (lines). The portfolio includes a large number of prospects with relatively small success case volumes.

A prospect portfolio will typically be screened with a cut-off success volume, representing the volume of gas required to justify the cost of wells and infrastructure required to discover and develop the field. The cut-off volume will vary depending on the distance from the prospect to existing infrastructure both for gas export and as a location from which to drill. A prospect within drilling reach of an existing platform on which there is excess gas handling capacity will be commercially viable at a lower success volume than a remote prospect requiring mobilization of a drilling rig and subsea controls and flowlines to tie back to production infrastructure. The impact of applying a cut-off volume to the prospect portfolio is presented in the figure below. Applying a cut-off volume will reduce the portfolio expected volume from 6,272 Bcf as follows

- 100 Bcf cut-off would result in a portfolio expected volume of 5,691 Bcf.
- 150 Bcf cut-off would result in a portfolio expected volume of 4,916 Bcf.
- 200 Bcf cut-off would result in a portfolio expected volume of 4,462 Bcf.

Figure 7-6 Ryder Scott Prospect Success Volumes and Cumulative Portfolio Risked and Unrisked Volumes

(source: Ryder Scott)

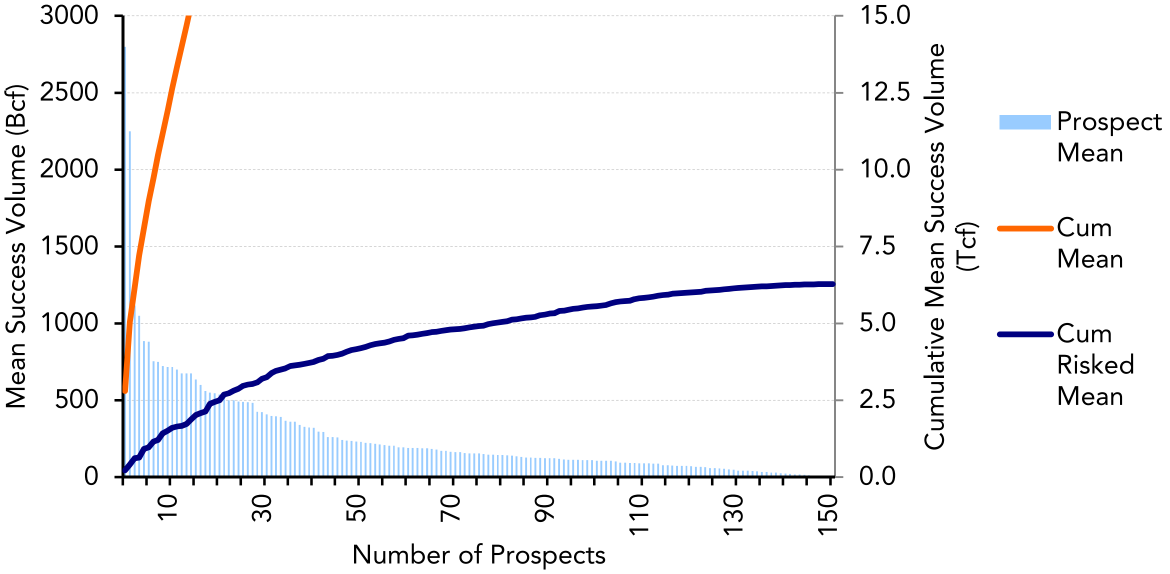
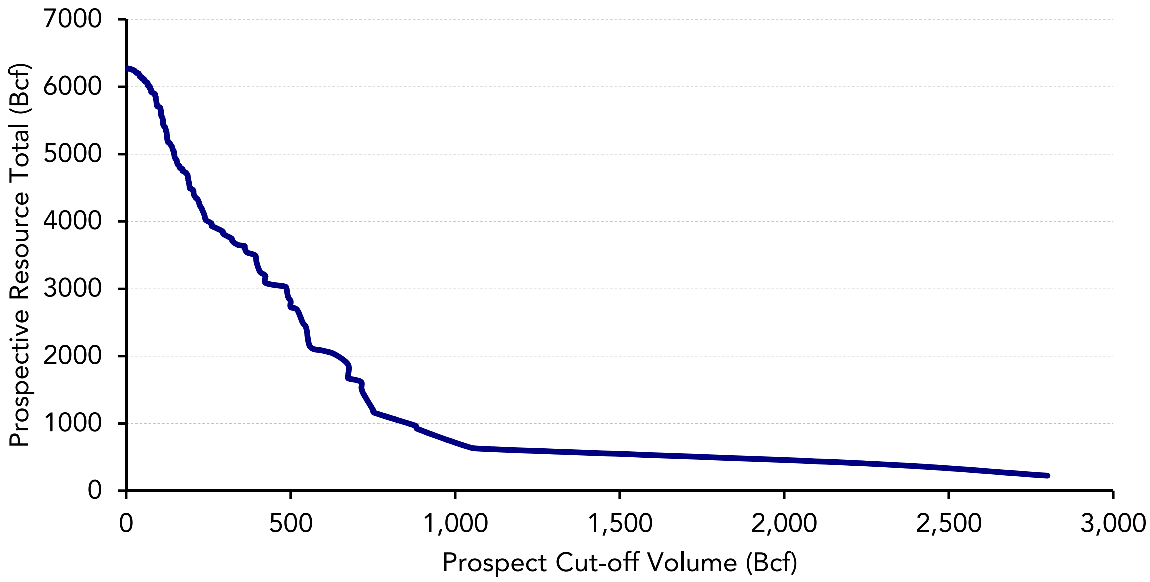


Figure 7-7 Ryder Scott Prospect Risked Cumulative Volume vs Prospect Cut-off Volume

(source: Ryder Scott)



It must also be remembered that the estimation of the Probability of Success of prospects is not a precise science, which introduces significant uncertainty to estimates of expected prospective volumes. The average Probability of Success for the prospect portfolio is 15%. The unrisked resource volume, representing a theoretical success rate of 100% exceeds 40,000 Bcf. While this is not a credible scenario it illustrates that there is significant uncertainty in the risked prospective resource estimate.

Finally although no map of the prospect locations was provided in the Ryder Scott report, it is assumed from the level of information available to the reserves certifier that these are dominated by shallow water (<300 m water depth) prospects adjacent to the island of Trinidad and the general area of development infrastructure. The prospectivity of the deepwater area is yet to be substantially tested and the results of exploration wells in the deepwater PSCs may impact estimates of prospective volumes significantly.

7.2.2.4 Production Profile Uncertainty Range

There are three key factors that drive uncertainty in the overall gas production profile:

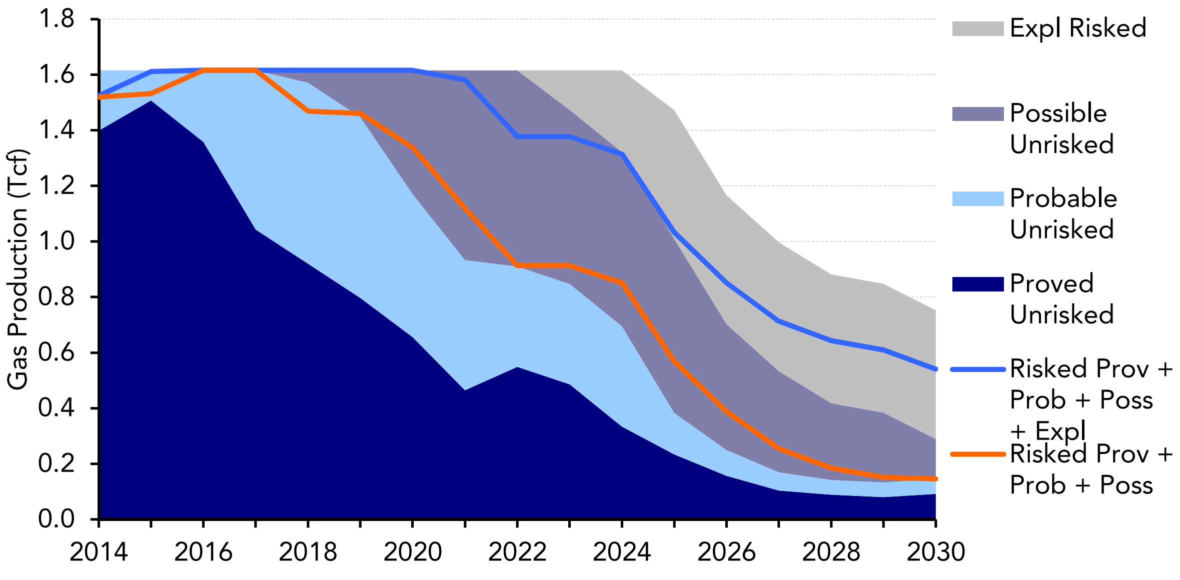
- Uncertainty in the recoverable volumes from discovered resources, represented by the range of 1P, 2P and 3P reserves.
- Uncertainty in the success rate from exploration of the prospective resource portfolio.
- Uncertainty in the commercial viability and development timing of undeveloped reserves.

Figure 7-8 provides some insight into the potential magnitude of the first and second uncertainty by plotting the expected profiles with and without exploration success over a background of unrisked discovered resource categories and risked prospective volumes.

The risked (mean) profile for reserves is similar to the Proven + Probable (P50) profile which is to be expected.

Figure 7-8 Ryder Scott Deterministic Sum of Unrisked Reserves and Risked Prospective Resources

(Source: Ryder Scott)



The pitfalls of summing probabilistic reserve categories is explored in Appendix D. The Proven Reserves value for a given field has a 90% probability of being exceeded by the actual recovered volume. The chart below presents the arithmetic sum of proven reserves which would only be representative of the 1P volumes of the portfolio if there was complete dependency between reservoir outcomes across the portfolio (i.e. a low outcome in one reservoir would give high certainty of a low outcome in other reservoirs). This will not be the case and so the sum of proven reserves represents an estimate which has higher than 90% chance of being exceeded by the actual recovered volume. The range presented by the sum of Proven Reserves on the low side and the sum of Proven + Possible + Probable on the high side is therefore wider than the true 1P – 2P – 3P range, but nonetheless provides an upper bound on the uncertainty range.

The chart does however illustrate that the expected exploration success volume from the current portfolio of shallow water prospects is not expected to have a significant impact on plateau duration and is probably similar in magnitude to the uncertainty in recovery from discovered fields.

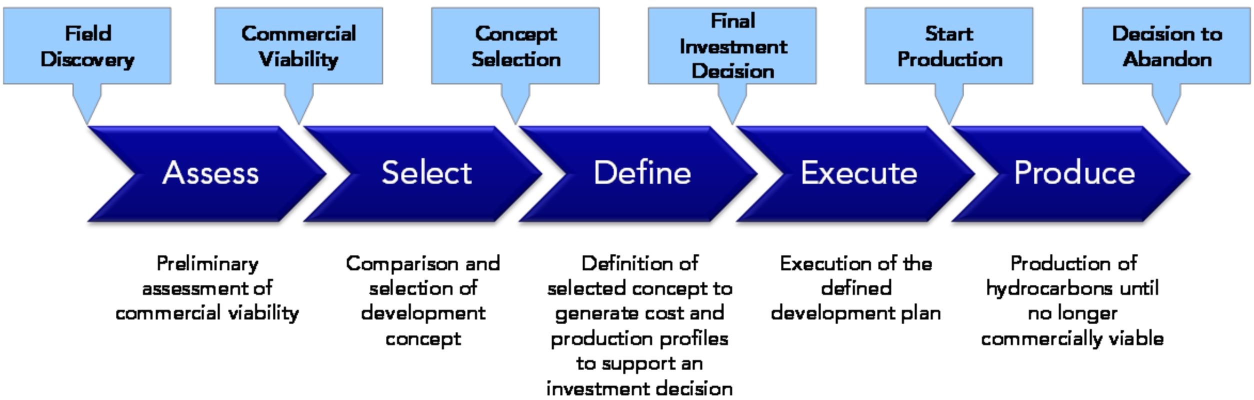
7.3 OPERATOR DEVELOPMENT PLANS

7.3.1 Summary of Operator Development Plans

The operators of licensed and contracted acreage in T&T are continuing to develop the discovered and prospective resources identified in their acreage. The Ryder Scott report reviewed the uncertainty in volume that could be developed from these assets and in the case of prospective resources, the chance of discovery. The report also includes production profiles from all the fields which represent technically credible development. However, the report acknowledges that the developments presented "were not subjected to rigorous economic evaluations" and also that "certain fields and/or reservoirs have been classified as reserves from a technical standpoint even if a detailed development plan was not available". The actual timing and capacity of field developments will be defined by the operator and JV partners and is likely to vary from the forecasts presented in the Ryder Scott report.

Operators typically apply a stage gate process to manage the development of fields illustrated in the figure below.

Figure 7-9 Typical Stage Gate Development Process



In order to transition from one development phase to the next the project team must collate a credible and commercially viable development plan covering technical, commercial and marketing issues. As the project progresses from the initial Assess phase through Select and Define phases, the estimated production and cost profiles and overall development timing will evolve and become more detailed and accurate. There is however no certainty of execution of the development, or of the final timing of a development until it has passed through the final investment decision and been sanctioned for execution. The plans and production profiles presented by the operators have therefore been split into existing and sanctioned developments (about which there can be a reasonable degree of certainty) and unsanctioned developments which although planned, cannot yet be relied upon to deliver gas on the forecast schedule.

The following sections describe the status of operator development plans as presented for the Gas Master Planning exercise.

7.3.1.1 bpTT

bpTT has a portfolio of approved development plans that have entered the execution phase:

- The Amherstia development came on production in October 2000, producing from both the Amherstia and Parang fields through 14 platform based wells. Future development plans for this field include recompletions and sidetracks using the existing wellbores and new drills.
- The Juniper development will produce from the Corallita and Lantana fields with first gas targeted for Q4 2017. Phase 1 will comprise five subsea wells. Phase 2 development will comprise two side-tracks for an additional 280 Bcf of Contingent resources.
- Production from the Kapok field platform began in 2003. The development consists of ten gas wells and associated sidetracks, with production from 22 reservoir segments, including two fault blocks in the Parang accumulation. Reserve and resource progression activities include an infill-drilling program of new drills and recompletes which are underway in the 2014/15 period.
- The Mahogany field has been developed with two fixed platforms, Alpha and Bravo. A total of 27 reservoir segments, including a thin oil rim have been developed through a series of horizontal and deviated wells. Future development of the field hinges on the application of multizone technology and recovery of compression resources.

bpTT has also prepared plans which are yet to be sanctioned for the development of additional assets in their acreage

- Angelin is scheduled for development and further appraisal in 2018 and first gas in 2019 as a tie-back through a normally unmanned installation (NUI) platform tied back to Cassia B via the Mango pipeline.
- Cannonball was brought into production in March 2006 via three producing wells. Further development would focus on recompletion of existing wells and possible appraisal well to a deeper target.
- The Cashima field was brought into production in 2008 through 6 wells. Future development of Cashima involves recompletions and sidetracks from existing wells and new drills to the NEQB and EQB fault block via extended reach drilling from the Cashima platform.
- Production from Cassia began in 1983, with 9 wells accessing 4 reservoirs. Deeper reserves remain undeveloped at this stage.
- Development of the Coconut field is planned as a subsea with a tie-back to the Cashima platform.
- Production from the Immortelle field commenced in 1994. Production through 25 wells is mainly gas but several sands have thin oil columns below gas caps and these have been developed through horizontal producers. Future development comprises of sidetracks, recompletes and a new drill.

- The Manakin field is located in Block 5(b) and reservoir segments cross the Venezuela-Trinidad maritime boundary. Execution of the Manakin project relies on the Juniper development. The Manakin facilities design will comprise three subsea wells linked via a "daisy chain" arrangement, tied back to Juniper via an 8 inch multiphase flow line.
- The Mango Field is a lean gas condensate accumulation on production since 2007 from seven wells targeting four reservoir sands. Future development opportunities comprise sidetracks, a recompletion and new drills.
- The Parang Field is part of the Greater Cassia Complex. Development of the eastern part of Parang was sanctioned in 1998 as part of the Amherstia development. The western part of Parang was sanctioned in 2002. Of the 14 wells drilled from Amherstia, three have produced reserves from western Parang reservoirs (reserves booked in Amherstia). The development of remaining Parang resources are currently planned from the Amherstia and Cannonball platforms.
- SEQB gas bearing reservoirs are shallow and require a low operating pressure in order for its reserves/resources to be produced. As such its development is currently tied to the implementation of compression, which at present is scheduled for 2021. Production from this field is planned from four wells and is now scheduled for start-up in 2021 with the addition of a new build compression platform bridge linked to the existing Amherstia facility.
- Onshore compression at the ALNG facility at Pt. Fortin is expected to reduce the system pressure by circa 200-400 psi for all hubs with the exception of Cassia B. Cassia B hub will remain at high pressure and feed directly into the NGC line. Onshore compression is expected to commence in 2017.
- Offshore compression assumes the installation of an Amherstia B compression platform that lowers the system pressure at all Amherstia Hub and Cassia Hub fields. This will occur in two phases reducing the system pressure down to circa 500psi in 2021 and 350psi in 2025 respectively. Offshore compression will be installed for all hubs with the exception of the Mahogany hub, which is currently not part of the project scope. Additionally the offshore compression project will allow efficient depletion of SEQB and other shallow gas reservoirs.

7.3.1.2 BGTT

BGTT developments cover ECMA and NCMA areas. The ECMA area development is centred on the Dolphin and Dolphin Deep developments. The Starfish field started production end 2014 as a subsea tie-back to the Dolphin platform. Development opportunities in this area include:

- Dolphin infill (target selection in progress, Sanction planned 2015, first gas 2017).
- Mahi Mahi exploration target (ready to drill).
- ECMA Compression (in concept select) – RFSU 2019.
- Grenadier (in concept select).
- Dolphin Deep Pliocene (seismic studies).
- Starfish terrace (seismic studies).
- Block 5c Bounty and Endeavour development. Bounty appraisal 2015, sanction 2016, RFSU 2019.
- Block 5d Lobster prospect, possible parallel development with 5c.

- Block 6 Manatee – Loran cross-border with Venezuela – negotiating agreements to support preparation of a development plan.

The NCMA area is centred on the Hibiscus field with production also from Chaconia, Poinsettia, Ixora, Bouganvilea, and Heliconia. First gas was achieved in 2002 and compression was started in early 2014.

The Central Block development produces from the Carapal, Baraka and Baraka East fields, all of which are on production.

7.3.1.3 EOG

Production is derived primarily from the Osprey development in block U(a) and the Pelican complex in SECC serving the Pelican, Ibis, Parula, Oilbird and Kiskadee/Banyan. A smaller contribution is made from the Toucan field in block 4(a). Immediate development plans focus on:

- 2nd stage compression planned for Kiskadee (2017), Parula (2018) and Oilbird (2019).
- Oilbird development and exploration (approved).
- Toucan compression.
- A five well programme in EMZ.

A series of future unnamed projects are in earlier planning phases to maintain production at circa 500 MMcf/d until 2021, after which a decline is forecast through to 2027. EOG have identified 2,200 Bcf of unrisked exploration potential in their permits.

7.3.1.4 BHP

BHP holds two shallow-water blocks. A number of fields in Block 2(c) PSC have already been developed: Canteen (oil & gas), Kairi (oil & gas), Horst (gas with oil rim), Aripo (gas). Angostura (Phase 3, gas) is in execution with RFSU scheduled in 2016. There are no plans to develop the Howler gas discovery. Block 3(a) PSC contains two discoveries which are currently under review to determine their commerciality:

- Delaware (gas) (market development, non-commercial).
- Ruby (gas) (market development possible appraisal).

BHP hold interests in a number of deep water blocks: TTDAA 3, TTDAA 5, TTDAA 6, TTDAA 7, TTDAA 14, 23a, 23b, TTDAA 28, TTDAA 29. This acreage is currently in the exploration phase and there are no firm development plans.

7.3.1.5 Centrica

Block NCMA-4 is in shallow to moderate water depths (<200 m) and contains Iris, Orchid and Jasmine fields. Block 22 is in moderate to deep water depths (300-1,500 m) and contains several discoveries: Cassra, Cassra Satellites, Sancoche and part of the Iris field. Extensive development studies for NCMA-4 and Block 22 include tie-back to ALNG and either a midsized LNG or CNG project on Tobago. With the change of government in Puerto Rico, the identified CNG buyer, Centrica is pursuing export to ALNG, either via Cove Estate in Tobago and into the existing NEO pipeline or through a tie-in to the Hibiscus pipeline. Centrica's development plans anticipate moving through concept selection and into concept definition in 2015 with FID in late 2016 and first gas early 2020. The gas profile provided commences in 2021, which allows for some schedule contingency but still relies on substantial development progress in

2015. Progress into concept definition will require greater clarity on access to third party infrastructure, in particular capacity at ALNG.

7.3.2 Operator Production Forecasts

The major operators have all provided forward production forecasts as input the Gas Master Plan. These have been combined with assumptions on the profile of the remaining 5% of production based on historical decline and Ryder Scott forecast to develop a forward production profile driven by the operators' business plans.

The profiles generated in this exercise were split into the following categories:

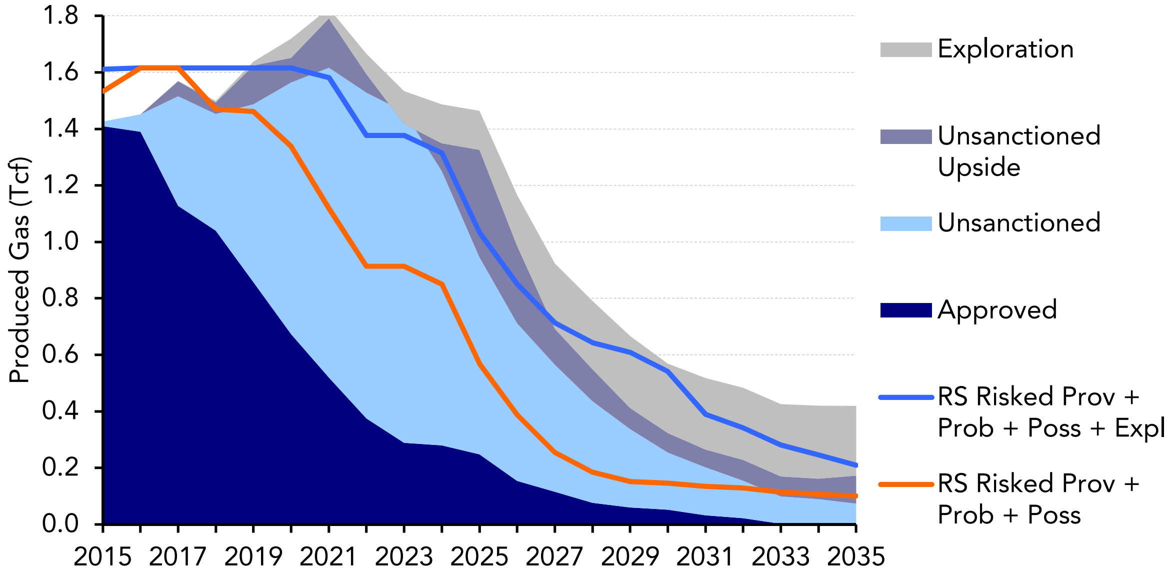
- Approved: gas production from existing developments and sanctioned extensions and new developments;
- Unsanctioned: gas production from the base case of planned developments which have not yet been sanctioned for execution;
- Unsanctioned Upside: incremental gas production from upside scenarios in planned but not yet sanctioned developments (where they have been provided);
- Cross-Border: gas production from the Manatee and Manakin fields operated by Chevron and BP respectively;
- Exploration: expected volume of gas from the portfolio of prospects across all acreage

The definition provided on exploration success volumes varied between operators, but a total of 9,280 Bcf of success case profiles were provided. Given the highly uncertain nature of the outcome of an exploration programme as described in Section 7.2.2.4, the operator's success case profile has been scaled to deliver a total of 4,460 Bcf of production, being the expected outcome of the prospects identified in Ryder Scott's reserves report with a cut-off of 200 Bcf minimum commercial volume applied. This achieves the dual objectives of presenting an exploration success volume which represents the entire portfolio of prospects with a development timeframe specified by the operating companies. The result of this analysis is presented in the graphic below, with the operator driven forecasts presented as solid areas and the previously derived levelled Ryder Scott profiles as lines for comparison.

The profiles presented in this section are limited to shallow-water developments planned by operators and exclude potential deepwater supply and potential production from cross-border fields subject to negotiation with Venezuela. The potential timing of deepwater gas production is considered in Section 0. Scenarios testing the impact of producing both T&T and Venezuelan shares of cross-border gas fields through the T&T infrastructure are examined in section 7.4.2.

Figure 7-10 Forecast Production from Operator Business Plans and Ryder Scott Risked Profiles

(source: Ryder Scott, bpTT, BGTT, EOG, Repsol, BHP, Centrica)



Several conclusions can be immediately drawn from this analysis:

1) The operator production profiles fall short of the demand potential of the ALNG plant and existing industries supplied by NGC.

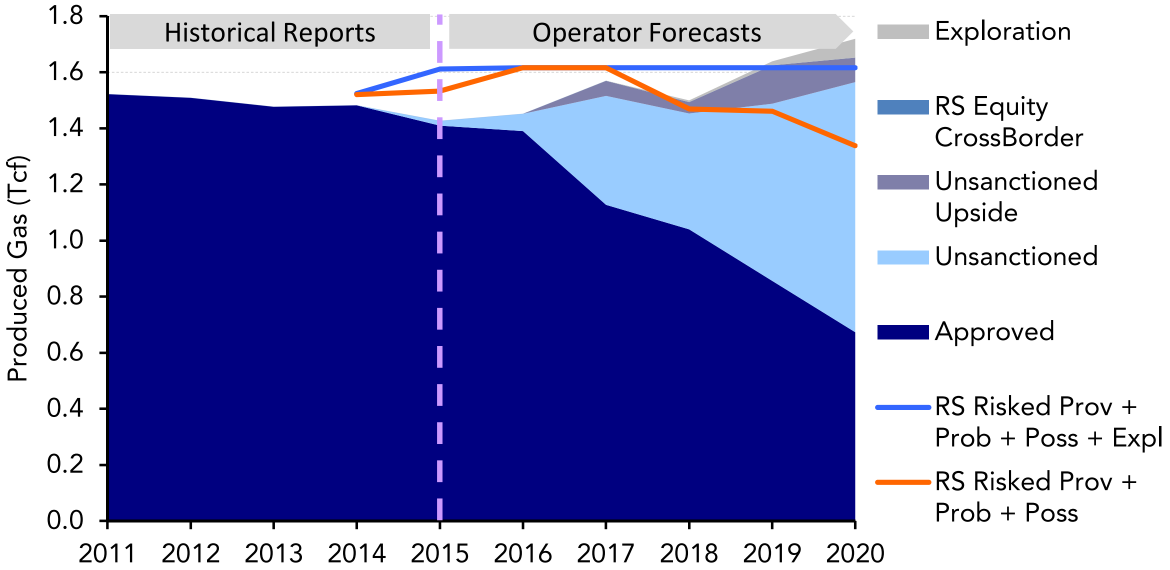
2) The operator production profiles rely heavily on unsanctioned projects which will only be realized if they pass operator economic screening hurdles and proceed into execution.

3) Overall the operators have plans to develop gas volumes in excess of the risked mean presented in the Ryder Scott reserves report.

The shortfall in production compared to the current consumer capacity presents the most immediate concern for the T&T gas industry. The production level that can be relied upon for the remainder of the plateau period is dependent primarily on approval of unsanctioned projects and, towards the plateau end, on exploration success. Given that not all unsanctioned projects will progress on time, a forecast production of 1.4 Tcf/y (circa 3.85 Bcf/day) is a reasonable planning basis allowing for upside and exploration success to offset unsanctioned project delays.

To confirm the consistency of the forecast dataset with actual gas production levels over the last few years the historical and forecast datasets have been merged. Figure 7-11 presents gas production since 2011 and the operator forward forecast until 2020.

Figure 7-11 Transition from historical data to Operator's Forward Production Profile
(source: Ryder Scott, bpTT, BGTT, EOG, Repsol, BHP, Centrica)



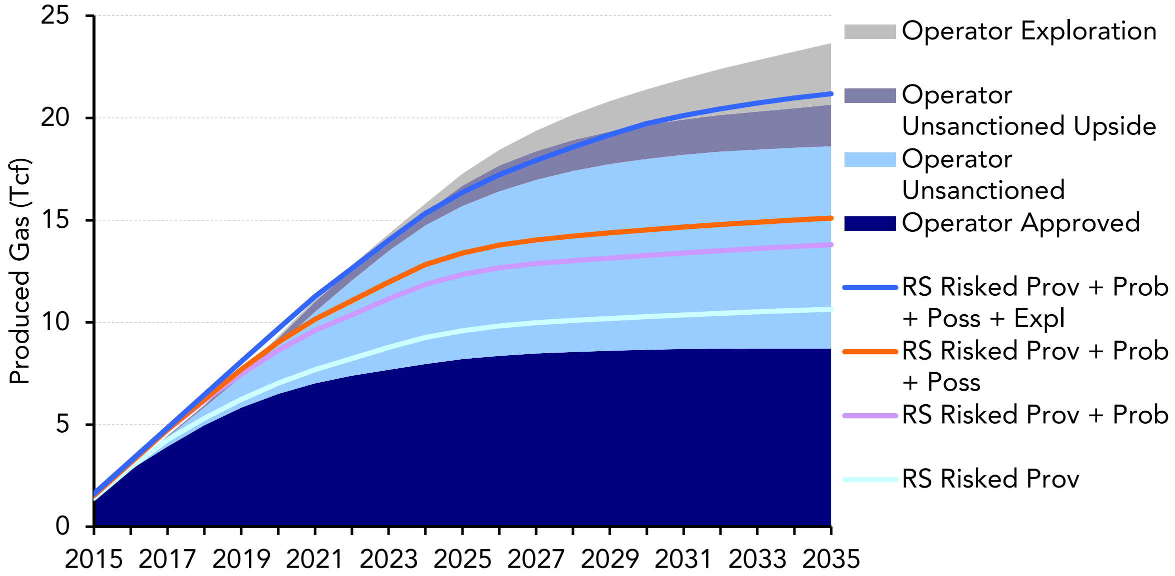
This shows a relatively smooth transition as part of a consistent trend of gradual production decline between the historical production data and the forward forecasts, confirming that the short term forecasts appear to be calculated on a realistic basis.

Figure 7-12 compares the cumulative volumes forecast by Ryder Scott (levelled to market constraint) with the cumulative forecasts prepared by the operators (solid areas on graph). The total cumulative volumes of gas identified by the operators for potential development is high compared to the Ryder Scott estimates, albeit on the assumption that all identified developments proceed. Ryder Scott's risked outcome excluding exploration is 15,400 Bcf, compared to the operator's Approved and Contingent of 18,400 Bcf. When development upside and Cross-Border gas is added this total rises to 23,100 Bcf. The dependence of Operator forecasts on as yet unapproved developments is also clear, with the operator's approved forecast falling below the Ryder Scott Proved level. This is not inconsistent, as the definition of proven reserves allows gas volumes for which development is likely to be approved within 5 years.

The heavy reliance of the forecast profile on unsanctioned projects post 2017 emphasizes the importance of operator decision making processes to GORTT. Within five years more than half of the forecast production is expected to come from projects that have not yet been sanctioned by the operators and joint venture partners. Any delay in sanction of the incremental developments providing these gas volumes will cause a decline in short term production levels. Given that these developments are targeting discovered volumes the decision making will be driven primarily by the economics of the incremental developments, which in turn is driven primarily by costs, gas prices and fiscal terms.

Figure 7-12 Cumulative Gas Profiles from Ryder Scott (RS) and Operators

(Source: Ryder Scott, bpTT, BGTT, EOG, Repsol, BHP, Centrica)



7.4 MEDIUM-TERM GAS SUPPLY

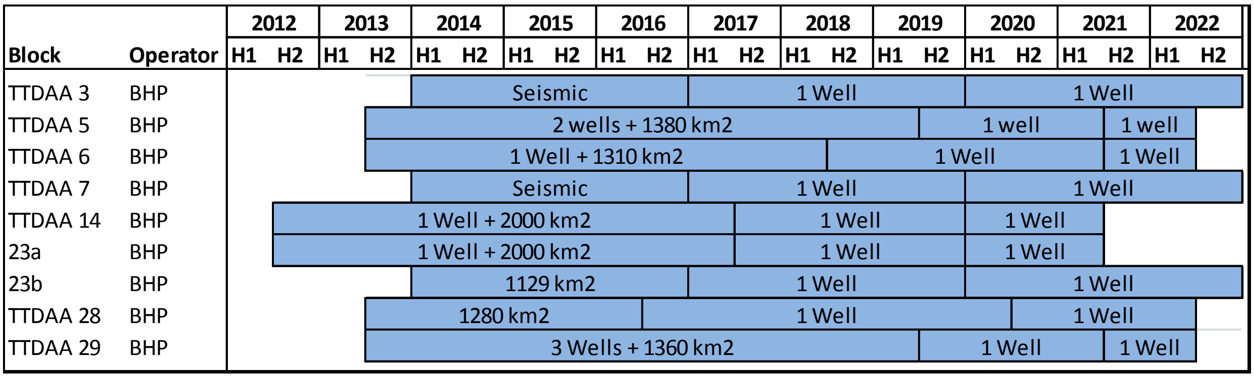
7.4.1 Deepwater Potential

7.4.1.1 Exploration Programme

A total of nine deepwater blocks have been awarded from bid rounds in 2010/11, 2012 and 2013, all operated by BHP. The work plans for these blocks are presented in Figure 7-13.

Figure 7-13 Deepwater Exploration Work Programmes

(Source: bpTT, BHP)

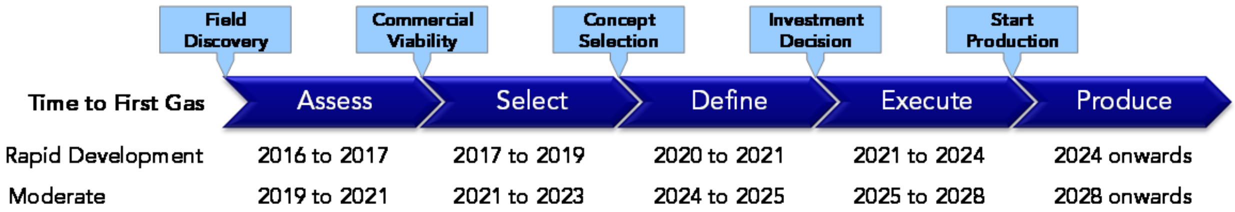


Each PSC has a term of 9 years split into three phases. Across the seven blocks a total of 8 wells are committed in the work programme of the first period of the blocks which end between 2016 and 2019, depending on the block terms. BHP is planning a mid-2016 drilling campaign to fulfil these commitments. An additional well is included in the work programme for each block for each of phase 2 and 3. Given typical success rates in exploration acreage of 10-20%, this suggests perhaps one or two discoveries in the first period with one or two further discoveries across the second and third periods. Of these some may be oil prone and any gas discoveries that are made may prove to be commercial once economic screening has been performed.

7.4.1.2 Commercialisation Timeline

The commercialisation timeline for deepwater acreage is significant. Given the exploration timeline, early appraisal and assessment of commercial potential is unlikely to be complete for a deepwater discovery before 2020. The assessment of deepwater technology in Section 3.3 suggests that platform infrastructure of some kind will be required to support production from most of the deepwater areas which will impact the execution timing.

We have considered two possible schedules, one based on a very rapid development of a clearly commercial discovery made early in a 2016 drilling campaign and on the basis that further appraisal drilling and seismic can be completed in parallel with early development planning. A second more moderate schedule reflects further iteration and optimisation of the development plan before sanction to execute.

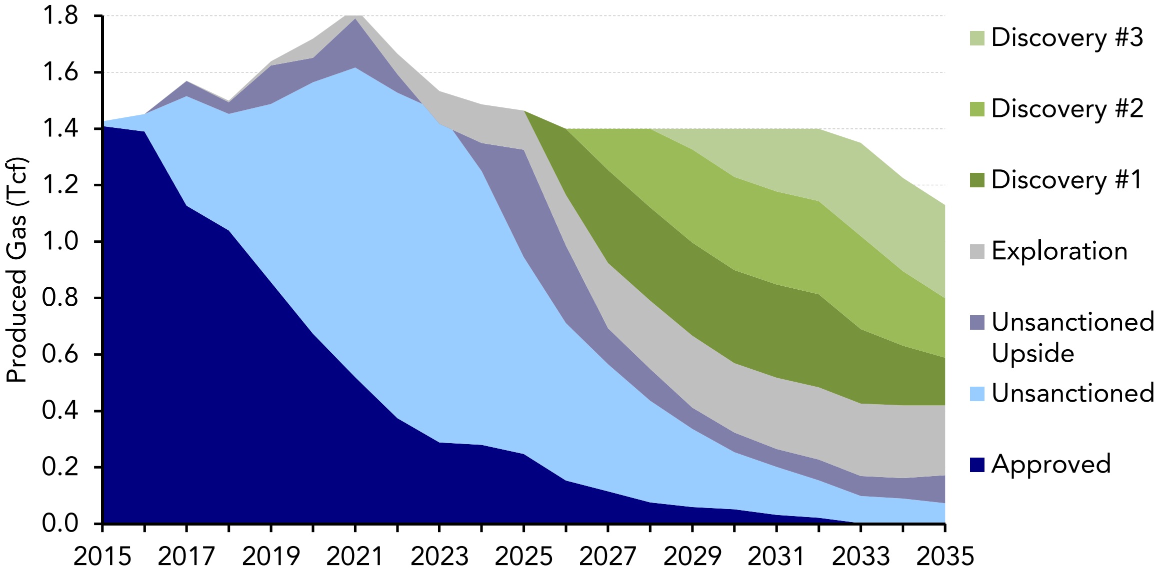


A notional discovery of circa 3,000 Bcf could sustain a production plateau of 1 Bscf/d for about 5 years before slipping into decline as the field is depleted.

To maintain the current plateau rates in the absence of cross border gas supplied by the shallow fields, two such developments would be required by 2026 and 2027, followed by a third in 2029, as illustrated in Figure 7-14. This would be an impressive run f discoveries from a frontier exploration area. Discovery of fewer or smaller fields would reduce the contribution to maintaining the plateau accordingly.

In order to improve the chances of production from deep water fields coming on stream within the notional development timeframe described above, the award of further acreage blocks with firm exploration drilling work programmes should be pursued by MEEA.

Figure 7-14 Deepwater Discoveries Required to Maintain Plateau



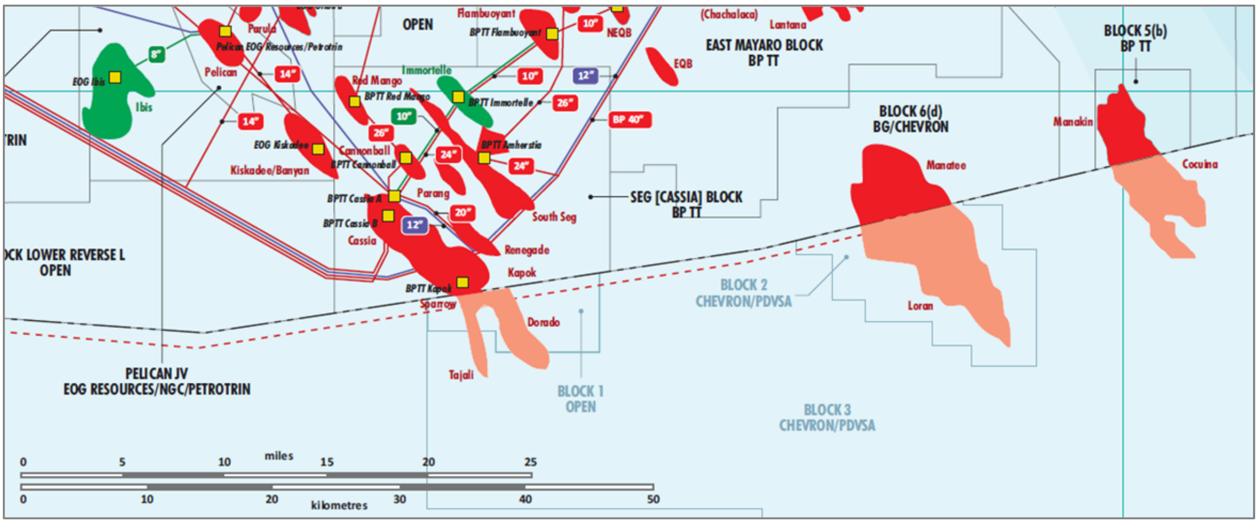
7.4.2 Cross-Border Gas Potential

Three discovered gas fields span the marine border with Venezuela:

- Loran–Manatee gas field
- Manakin–Cocuina gas field
- Kapok – Dorado gas field

Figure 7-15 Cross-Border Field Locations

(Source: Petroleum Economist)



Poten has identified two sources of reserve estimates for these fields, the Ryder Scott reserves report estimates the recoverable volumes within T&T's boundaries and a Cross-Border Status Report tabulates the volume estimates reported by the Joint Working Group (JWG) established by the governments of Venezuela and T&T. Application of the percentage splits carried by the JWG to the Ryder Scott estimate of T&T reserves allows back calculation of total field volumes. Volume estimates from these two data sources are presented below.

By far the largest field is the Manatee Loran field containing up to 7,175 Bcf of gas. The Manakin Cocuina field is relatively small and will not have a significant impact on the country's overall gas supply position and the Kapok Dorado field is already in production by bpTT, the operator.

Table 7-5 Cross-Border Gas Volume Estimates

(Source: MEEA and Ryder Scott)

Field	T&T Share	Estimate Source	T&T Recoverable Gas (Bcf)	Total Field Recoverable Gas (Bcf)
Manatee Loran	26.94%	JWG	1,933	7,175
		Ryder Scott	1,434	5,323
Manakin Cocuina	66%	JWG	429	650
		Ryder Scott	263	398
Kapok Dorado	84.10%	JWG	264	314
		Ryder Scott	725	862

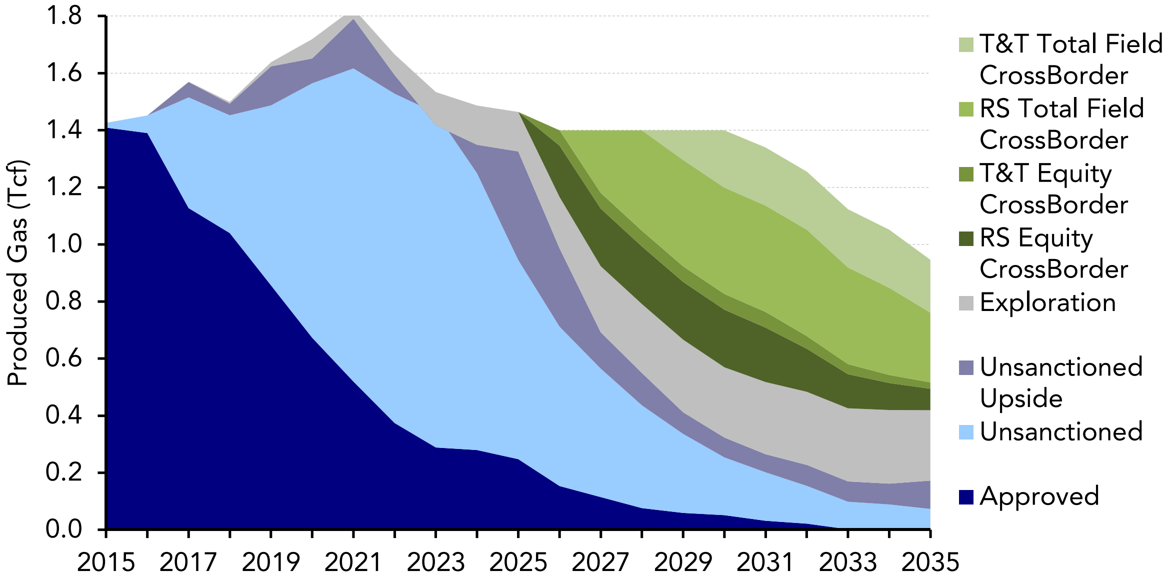
In September 2013 the governments of Venezuela and T&T signed an agreement that established the functional and governance structure to oversee the development of the Loran-Manatee gas field and agreed that the field would be developed via a pipeline to the Paria Peninsula on the Venezuelan coast where Venezuela's Mariscal Sucre project is also planned. More recently, February 2015 press reports have suggested that development of the field through existing T&T infrastructure could be under consideration again due to slow progress with the Venezuelan development project. This raises the possibility of the entire reserves volume being processed through the T&T infrastructure.

In order to illustrate the potential impact on T&T's gas supply profile we have assumed gas production begins in 2026. This allows several years for inter-governmental agreements to be executed as well as a timeline of circa 5 years for a project of this magnitude to pass through FEED, reach Final Investment Decision by the venture partners and also be executed. This timing also coincides with the availability of significant ullage capacity in T&T's gas processing infrastructure.

The impact of the potential range of gas volumes which may be produced from Loran Manatee on the overall gas supply forecast to T&T has been assessed, considering the equity volume estimated by Ryder Scott on the low side, up to the entire volume carried by the JWG.

The resultant gas profiles are presented in Figure 7-16. In each case it is assumed that no more than 11% of field reserves would be produced in any one year to allow responsible management of field depletion and avoid over investment in production infrastructure. This results in a production plateau of circa 6 years followed by a circa 7 year decline which may be considered aggressive, depending on evaluation of the reservoir performance.

Figure 7-16 Impact of Cross-Border Gas Scenarios on Production Profile
(Source: MEEA, Ryder Scott, bpTT, BGTT, EOG, Repsol, BHP, Centrica)



The dark green segment represents the equity gas volume estimated by Ryder Scott. It does not impact the end of plateau production but does help to slow the speed of decline in production.

Production of the equity volumes estimated by the JWG extends the expected production plateau by one year from 2025 to 2026. Adoption of the entire field volume estimate calculated by upscaling the Ryder Scott estimate by the T&T equity share, extends the plateau by a further year to 2028 and further reduces the rate of production decline.

Inclusion of the entire field volume estimated by the JWG in the production profile extends the production plateau out to 2030. While this offers the possibility of a 5 year extension of plateau production and life of the downstream gas industry it should be remembered that this scenario depends not only on Venezuela agreeing to development of the entire gas field (of which they own 73.06%) through T&T infrastructure, but also on the realisation of the reserves estimate carried by the JWG which is still subject to some uncertainty.

7.5 CONCLUSIONS

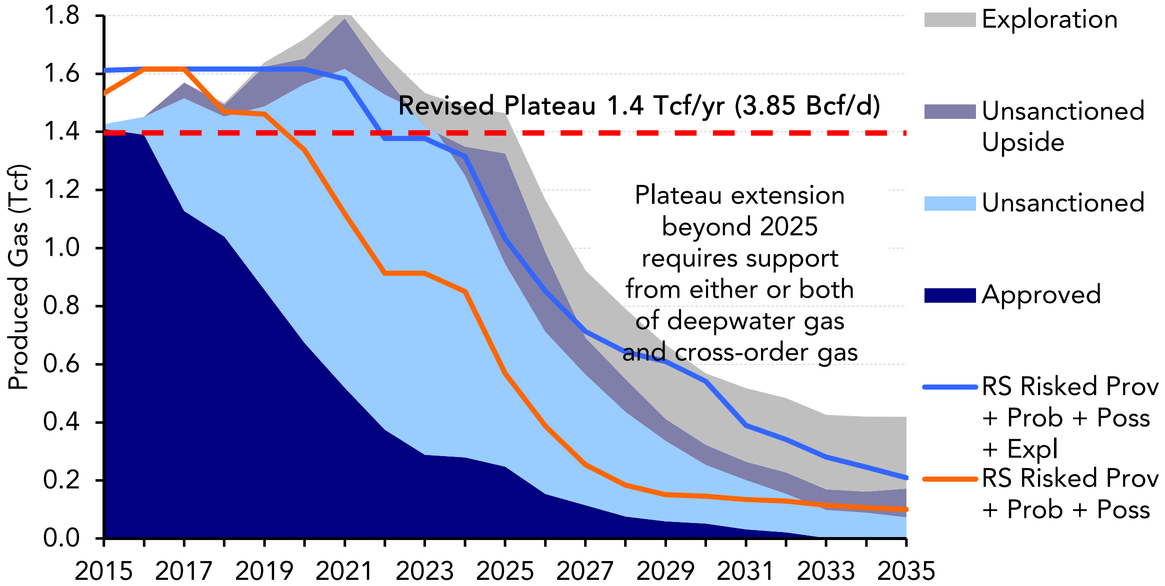
Review of the data provided for the Gas Master Plan leads to the following conclusions on the forward supply of gas to T&T's downstream industries:

- Gas supply rates of circa 3.85 Bcf/d (average) are likely to persist in the coming years.
- Beyond 2017 gas supply is increasingly dependent on offshore projects which are as yet not sanctioned for development. The 3.85 Bcf/d plateau allows for deferral / cancellation of only a minority of those projects.
- Plateau production from the T&T shallow-water area is expected to drop below the revised 3.85 Bcf/d by 2025.
- Two other mid/long term sources of gas have been identified, both of which carry uncertainty in timing and volume of supply:
  - Supply from deepwater developments relies on exploration success in the planned 2016-17 drilling programme.v Three discoveries of 3 Tcf recoverable each would be required to extend the plateau beyond 2030
  - Supply from cross-border fields which extend into Venezuelan territory relies on the outcome of government to government discussions. Only 27% of the largest field (Manatee Loran) lies in T&T waters but for any significant extension of plateau production the entire field would need to be processed through T&T infrastructure

A combination of moderate deepwater success and some gas production from cross border fields would provide some support to extend plateau or reduce the rate of production decline post 2025.

If there has been no deepwater exploration success by 2018 or significant progress in cross-border discussions with Venezuela by 2020 then the industry should prepare for a further decline in long-term gas supply levels.

Figure 7-17 Summary Forward Gas Supply Position



Section 8 Upstream: Mobilising Production

Upstream operators in T&T have prepared plans to support and extend plateau gas production through development of discovered resources in shallow water and cross-border areas subject to negotiation with Venezuela, in combination with an active exploration programme in the deepwater areas to the east of Trinidad which, if successful, would provide a valuable additional source of gas. This section reviews the hurdles to continued investment in each area and identifies opportunities to stimulate investment to support future gas production to T&T.

8.1 REVIEW OF SHALLOW-WATER UNSANCTIONED PROJECTS

Production rights in T&T shallow-water areas have been granted under two regulatory systems. The industry was initially established under a license tax-royalty scheme in onshore and shallow-water offshore areas. In 1996 GORTT commenced the award of PSCs in offshore areas. The terms of the PSCs issued over development acreage have evolved over time, but at the heart of each contract is a limit on the pace of cost recovery from production and a matrix which defines how profit oil and gas is split between the contractor and GORTT as product prices and production rates vary. Currently, oil and gas production in T&T falls under both license and PSC concessions.

In order to assess upstream operators' appetite to invest in development of their gas reserve base, a set of development scenarios representing typical opportunities under consideration by operators have been modelled under fiscal regimes representing the terms currently in force in T&T, to determine the contractor rate of return and GORTT take that can be expected.

The impact of potential amendments which could be made to infrastructure access policy and fiscal terms were then assessed to determine the options available to the regulator to incentivise the sector from a policy and legislative perspective (see Section 14).

8.1.1 Development Project Characteristics

Operators were asked to provide data on the planned developments of gas fields required to support their forward production forecasts. The data provided varied in format and detail, but allowed compilation of production, capital and operating cost profiles of planned developments.

The total undiscounted pre-tax unit cost (capex plus opex) in $/Mcf provides a high level measure of the cost base of future development concepts and is presented in Figure 8-1 as a scatter plot, showing a cluster of small, low cost developments with a smaller number of higher cost but higher volume gas developments. Figure 8-2 presents this same dataset as a function of cumulative developed gas with projects ordered by their unit cost.

In order to test shallow-water development economics three generic development concepts were selected, representing the following development categories:

- Incremental development phase of existing shallow-water facility.
- Brownfield development leveraging existing shallow-water infrastructure.
- Greenfield shallow-water development.

Figure 8-1 Total (Capex + Opex) Unit Cost of Planned Development

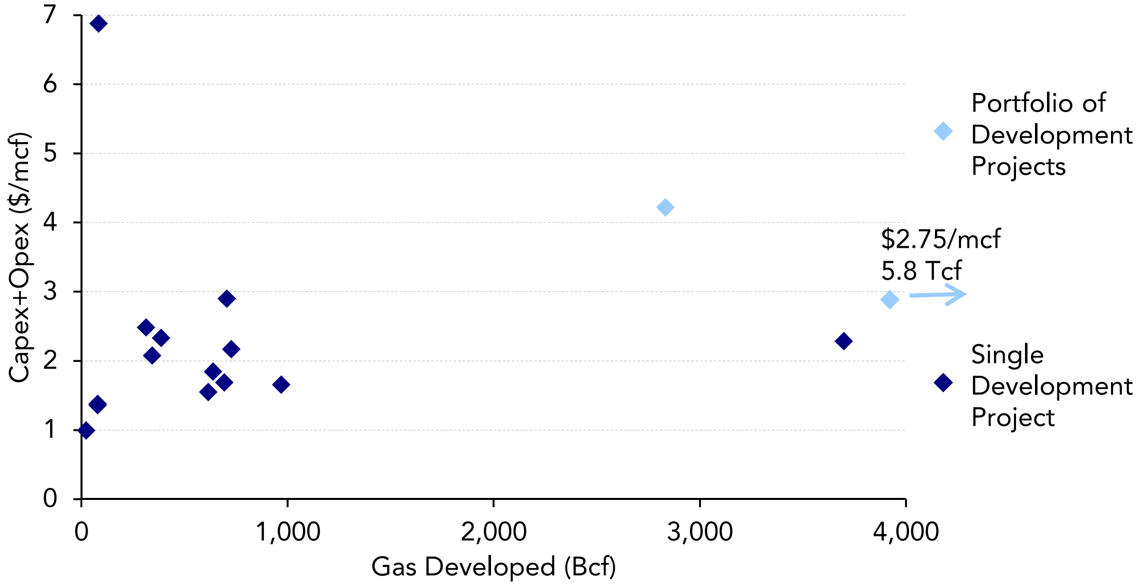
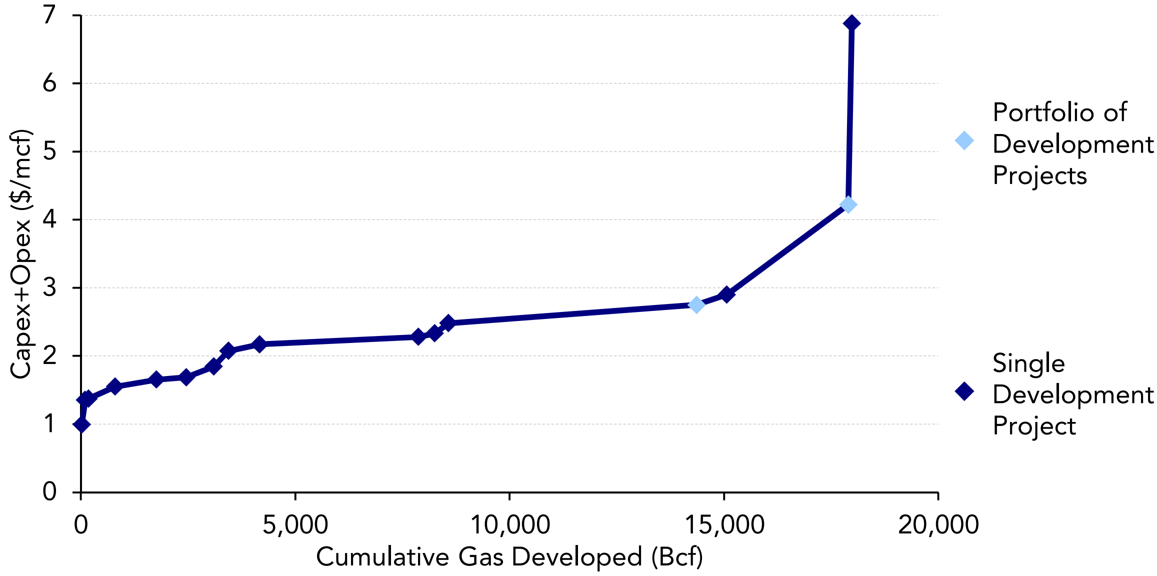


Figure 8-2 Cumulative Unit Cost of Planned Developments



The incremental project adds a relatively modest ~340 Bcf of gas and ~4.5 MMbbl of condensate (13 bbl/MMcf) but for a relatively competitive undiscounted pre-tax total cost of ~$2.30/Mcf. As an incremental project it is augmenting the existing supply capability of the foundation project and extending the production plateau. The production attributed to this project therefore ramps up over a period of five years as the foundation project production begins to decline away from the plateau production rate.

The brownfield development adds ~700 Bcf of gas and ~10 MMbbl of condensate (14 bbl/MMcf) from development of a new field close to existing infrastructure, which it leverages to reduce undiscounted pre-tax total cost down to ~$1.90/Mcf. Production ramps up rapidly circa 30 months after commencement of the project, with the short lifecycle reflecting the limited scope of infrastructure development. A generic opex cost has been assigned to this project to which any access fees charged by third party infrastructure providers would need to be added.

The greenfield development adds ~700 Bcf of gas and ~10MMbbl of condensate (14 bbl/MMcf) but at a higher unit undiscounted pre-tax total cost of ~$3.30/Mcf, reflecting the greenfield infrastructure burden on the project. Production ramp up is immediate, 60 months after the commencement of the project, reflecting the longer planning and execution cycle of the greenfield project.

These cases provide a cross-section of the concepts presented by the various operators. No attempt has been made to challenge either the development rationale or the cost estimates presented for review. These projects represent the operators' current view of development economics for additional gas supplies.

8.1.2 Production License Terms

The license terms currently in force in T&T were implemented in a discounted cashflow (DCF) model, relying on information provided by GORTT and license operators, as well as information in the public domain. These terms included the accelerated capital depreciation implemented in 2014

8.1.2.1 Taxes on Gross Revenues

Royalties in T&T apply to both gross gas revenues and gross oil/condensates revenues. We have modelled license terms with a gas royalty of 10% on gross gas revenues for gas production of 100 MMcf/d and above, reducing to 5% royalty for gas production of less than 100 MMcf/d. Gross oil/condensates revenues are subject to both a royalty and the Supplemental Petroleum Tax (SPT). We have modelled these two fiscal instruments by combining a royalty of 12.5% and the 33% SPT rate. The 33% SPT rate is the standard SPT rate that applies for standard development for a crude price evolving between $50/bbl to $90/bbl. Liquids revenue has been modelled at a price of $80/bbl. A discount on the SPT of 25% on the SPT rate is provided to mature fields (i.e. fields in production for more than 25 years) and small fields (i.e. fields with oil production totalling less than 1,500 bbl/d). The SPT discounted rate (75% x 33%) has been modelled for small field production < 1,500 bbl/d. Further discounts on the SPT are available for new field and deepwater developments, however there are no parallel concessions for the tax burden on gas revenue and given our focus on gas dominated projects we have not modelled these additional tax discounts on liquid production in this section.

Table 8-1 Supplemental Petroleum Tax Reference Rates

Crude Oil Price $/bbl	Standard rates	New Field	Deepwater
<50	0%	0%	0%
50 to 90	33%	25%	18%
90 to 200	= SPT rate +0.2%(Crude P - 90)		
> 200	55%	47%	40%

8.1.2.2 Other Taxes on Gross Revenues

The Green Fund Levy has been modelled at 0.10% rate to oil/condensates and gas gross revenues. A 4.00% tax rate on oil/condensate gross revenues has also been modelled at all production levels as a proxy for Petroleum Levy. The Oil and Gas Impost to help fund MOEEI has been modelled as follows: US$0.08/bbl for oil/condensate and US$0.01/MMcf for gas flows.

8.1.2.3 Net Taxes

The standard rate of 50% for the Petroleum Profits Tax (as compared to corporate tax rate of 25% for other sectors of the economy) has been modelled in the base license case. Deepwater assets (where more than 50% of the permit lies in water depths greater than 400 m) can take advantage of the discounted rate of 35% but this is not available to developments in shallow-water areas.

The Unemployment Levy of 5% and a Withholding Tax rate of 5% have also been modelled in the license case.

8.1.2.4 Depreciation Rates

Exploration costs incurred between 2014 and 2017 are 100% depreciated in the year they are expensed.

Other capital costs (including exploration post 2017) are amortised 50% in the year following the expense, 30% the subsequent year and 20% on the third year in the base case license. No explicit provisions have been made for abandonment costs under our license fiscal cases.

8.1.2.5 Summary of License Fiscal Terms

The key terms modelled in the license fiscal case are summarised in the Table 8-2.

Table 8-2 License Fiscal Terms

Fiscal Term	Base License
Gas Royalty	5% (<100 MMcf/d) 10% (>100 MMcf/d)
Oil & Condensate Royalty	12.5% on all liquids
Supplemental Petroleum Tax	33% on liquids (>1500bbl/d) 25% on liquids (<1500bbl/d)
Petroleum Profits Tax	50%
Depreciation	Exploration is expensed Development at 50%, 30%, 20%

8.1.3 PSC Terms

PSC terms awarded by GORTT have evolved over the years since the PSC was adopted as the primary acreage award mechanism in 1996. Our assessment of PSC terms is based on a limited sample of terms provided to us by the operators. In particular we have had access to very few examples of recent PSCs and have relied on that limited sample to develop the terms described below.

The PSCs follow a relatively standard structure with a proportion of revenue first being available to recover development capital and operating costs (cost production) and the remaining profit production being split between GORTT and contractor. Most contracts have a limit on the proportion of revenue which can be used as cost gas in any one year, with unrecovered costs being carried over for recovery in subsequent years. The speed at which costs can be recovered may also attenuated by a depreciation schedule limits the pace at which costs can be recovered e.g. a four year schedule of 40%, 20%, 20%, 20%.

8.1.3.1 Profit-Sharing Matrices

A common feature of the GORTT PSCs is the use of a matrix to define the contractor share of profit oil and gas as product prices and production rates vary. In general GORTT has proscribed the price and production rate bands for the matrix and bidders have then competitively bid profit-split percentages to win rights to the block. The gas production rate bands have remained relatively constant over the years, most contracts having the typical production bands summarised in Table 8-3. Some contracts vary slightly by combining the first and second bands to allow the addition of a 450 – 600 MMcf/d band, or split the second band into two bands at 50 – 100 MMcf/d and 100 – 150 MMcf/d, with the top band at 300 MMcf/d.

Table 8-3 PSC Profit Share Matrix Production Bands

Lower Exceptions	Typical Production Bands	Higher Exceptions
0 - 50 MMcf/d	0 - 60 MMcf/d	0 - 150 MMcf/d
50 - 100 MMcf/d	60 - 150 MMcf/d	150 - 300 MMcf/d
100 - 150 MMcf/d	150 - 300 MMcf/d	300 - 450 MMcf/d
150 - 300 MMcf/d	300 - 450 MMcf/d	450 - 600 MMcf/d
Over 300 MMcf/d	Over 450 MMcf/d	Over 600 MMcf/d

There is much greater variation in the gas price bands used to differentiate profit splits between “low” and “high” gas price environments. The first two PSC’s awarded in 1974 and 1993 had no gas price index on profit production split. From 1996 PSCs became the primary structure for new acreage release and indexing of profit split to gas prices was introduced. Between 1996 and 2002 the gas price bands were set to reflect low prevailing gas prices with bands between \$1 and \$2/Mcf and extended up to \$3/Mcf for the 2005 bid round.

Inflation of gas prices beyond the range envisaged by these bands was acknowledged in the 2011-12 PSC contract awards where price bands spanned the range from a low of \$3/Mcf up to highs of \$7/Mcf. This has resulted in a two-tier system with holders of older PSCs (1996-2002, 2005) burdened by low contractor profit gas splits at even moderate gas prices by present standards, while holders of later PSCs

(2011-12) and those without gas price indexing of profit splits (1974, 93) operate under terms intended by the original negotiation.

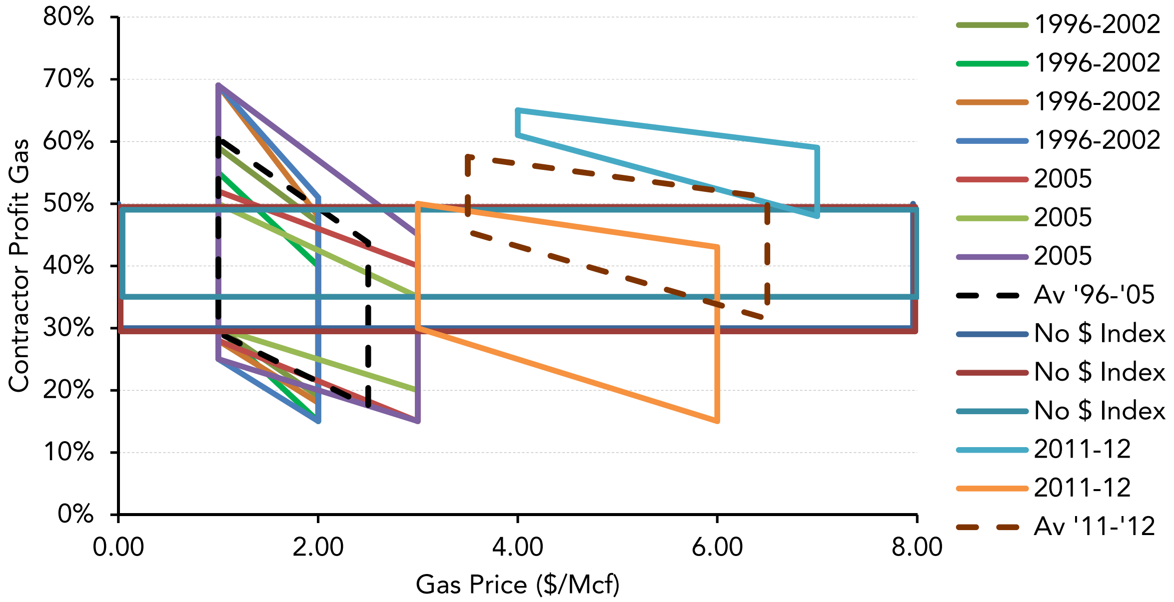
Table 8-4 1996 – 2005 PSC Profit Share Matrix Price Bands

1996 - 2002	2005 (typical)
<$1.00/Mcf	<$1.00/Mcf
$1.00 - $1.50/Mcf	$1.00 - $2.00/Mcf
$1.50 - $2.00/Mcf	$2.00 - $3.00/Mcf
>$2.00/Mcf	>$3.00/Mcf

The range of terms captured in current PSC contracts is illustrated in Figure 8-3, together with the average terms used in our analysis to represent the 1996-2005 PSCs, with gas price indexing between $1.00 and $2.50/Mcf to reflect the range of terms seen in that period. Assessment of the profit gas split in recent PSCs is based on the limited number of more recently executed PSCs in T&T made available for review. We have prepared a gas price matrix based on the average of the two 2011-12 examples.

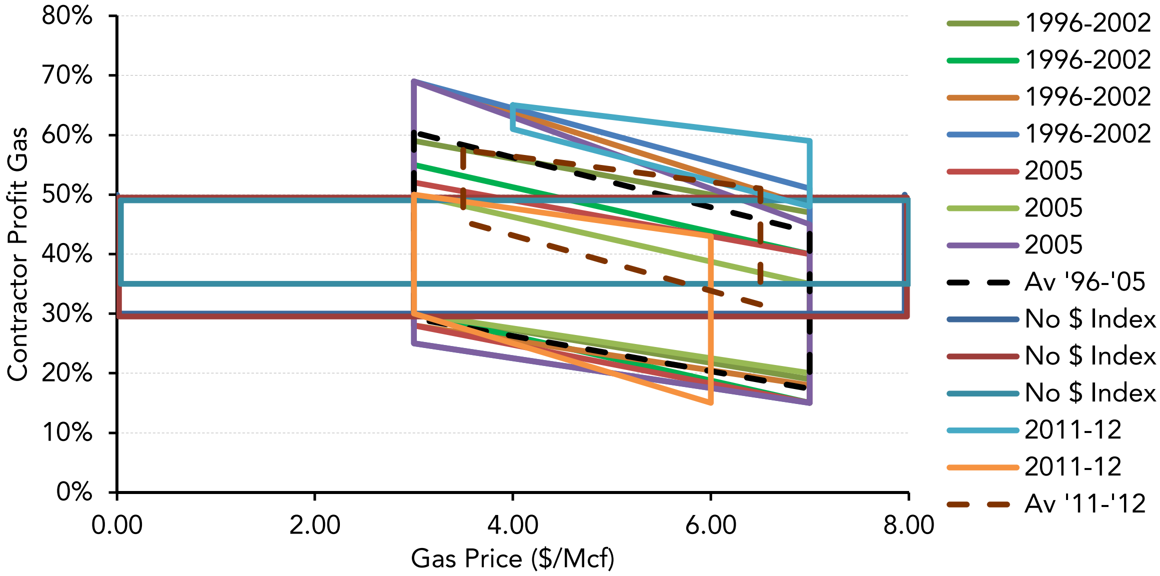
The disparity between PSC contract terms due to the inflation of gas prices above the profit gas price bands has had an impact beyond that considered during the negotiation of PSC terms. For instance at a gas price of $3.00/Mcf the range of operator profit gas split for high production rates in the 1996-2005 PSCs is 15-20%, the lowest in the matrix reflecting maximum production rates and gas prices considered during negotiation of the PSC terms. However, because this gas price is considered low in the 2011-12 contracts or has no impact on PSC splits without gas price indexing, the operator profit split on all but one of those PSCs is 30-35%, circa double the earlier PSCs, rising to 60% for the most favourable recent contract.

Figure 8-3 Profit Split and Gas Price Ranges Across PSCs



Operators of 1996-2005 PSCs with gas-indexed profit splits are therefore faced with a profit gas share that was negotiated for "high" gas prices being applied at prices which are low by international standards and also in comparison with the underlying cost of development with the current industry price structure.

Figure 8-4 PSC Terms Adjusted to Reflect Current Gas Prices and Developemnt Costs



To test the impact of eliminating this unforeseen disadvantage we have constructed a sensitivity set of terms which restore gas price bands to a range more compatible with current prices and costs ($3.00-$7.00/Mcf). The resulting adjusted 1996-2005 PSC terms and average case are illustrated in Figure 8-4. The adjusted 1996-2005 terms are considered as a sensitivity case in Section 8.2.3.

8.1.3.2 Cost-Recovery Cap Assumption

Shallow-water PSC terms reviewed by Poten have cost recovery caps between 40% and 65% of revenue for the main production periods. Some PSCs have increased cost recovery ceilings of up to 80% for initial production periods. There was no clear correlation between the date of PSC execution and the cost recovery terms.

All shallow-water PSC terms were modelled with a 55% cost recovery cap on both oil and gas revenues which represents the cost recovery terms in in the PSC's available for review. Deepwater PSCs have an 80% cost recovery cap on both oil and gas revenues and the impact if this were applied to shallow-water developments is considered as a sensitivity case in Section 8.2.3.

8.1.3.3 Depreciation Rates

Based on the information received regarding the two sets of PSCs the following depreciation patterns were applied for development capital expenditure other than exploration costs which are 100% depreciated in the year they are expensed for both set of PSCs:

- 1996-2005 PSC: Capital costs are depreciated 40% in the year following the expense, and 20% for the subsequent 3 years.
- Recent PSC: Capital costs are depreciated 100% in the year in which the expense is incurred.

8.1.3.4 Other PSC Fiscal Terms

All other financial obligations on the contractor were standardised and applied to both PSC models without distinction. We did not apply signature bonus because the analysis is focused on the development phase.

Block area rental fees, the funding to the scholarship program and the administrative charge were assumed to be a total of US$1.4 million per annum, escalated at 6% annually (6% being an average of the reviewed PSCs, which vary between 4% and 8%).

The training contribution to the University of T&T or the University of West Indies and the R&D contribution was simplified to 0.50% of oil and gas production

Production bonuses appeared quite standard among all PSCs, and were modeled with the rates described in the table below

Table 8-7 Production Bonus Table

Fixed Production Bonuses		Rolling Prod Bonuses		
kBoepd	$MM	(Fixed Fee for each Prod Increment)		
25	1.50	First	Increment	Fee
50	2.00	kboepd	kboepd	$MM
75	3.00	100	50	1
100	4.00			

An abandonment provision is made at a rate of $0.25/bbl deposited into an escrow account earning 4% interest.

Under PSC terms, the contractor is exempt from paying any other taxes, except for withholding tax. As per the license scheme, a 5% Withholding Tax rate was modelled.

8.1.4 Economic Analysis

8.1.4.1 Current Terms and Gas Prices

The generic development cases identified in Section 8.1 have been analysed in a DCF model in which the fiscal regimes described above have been implemented. The DCF model was set to determine the rate of return available to the contractor assuming a fixed gas price, escalating with inflation. The gas price was set at $3.10/Mcf, representing the average prices received by upstream producers in the last two calendar years (2013 and 2014). The results are presented in Table 8-5.

The following conclusions can be drawn from analysis of projects assuming a gas price of $3.10/Mcf:

- There is a broad range of return on capital depending on the characteristics of the project under consideration and the fiscal terms applied;
- The generic incremental development fails to meet screening levels under 96-05 PSC or existing license terms and while economics improve under recent PSC terms they still fall

short of typical screening hurdles. This preliminary analysis is conservative in that it does not consider the benefit on cost recovery of existing production in the PSC concerned. This is explored further in Section 8.2.3 and brings the incremental project economics up to screening thresholds under recent PSC terms;

- The generic shallow-water brownfield project is attractive to develop under all fiscal terms considered at the average gas price, although the rent from this project must be shared with the owner of the existing infrastructure used by the brownfield development;
- The generic greenfield projects requiring installation of significant new infrastructure are sub-economic at the average gas price under all fiscal terms considered.
- GORTT take from the developments is similar under the 96-05 PSC and standard license terms. The recent PSC terms result in GORTT takes of circa 75-80% of the standard terms on an undiscounted basis.

Table 8-5 Contractor IRR at $3.10/Mcf Gas Price

Development	'96-05 PSC	Recent PSC	License
Incremental	7.0%	10.6%	5.8%
Shallow Brownfield	16.9%	25.1%	15.8%
Shallow Greenfield	-5.3%	-0.6%	-5.8%

Table 8-6 GORTT Take at $3.10/Mcf Gas Price

(US$ million, nominal)

Development	'96-05 PSC	Recent PSC	License
Incremental	593	471	632
Shallow Brownfield	1,389	1,078	1,484
Shallow Greenfield	1,066	835	1,033

Shallow-water greenfield projects and incremental projects clearly require fiscal assistance or increased gas prices to reach commercial viability. This need is recognised for deepwater developments GORTT in the form of tax concessions and favourable PSC terms for recently awarded deepwater blocks, but no comparable incentives are currently available for marginal shallow-water gas developments.

8.1.4.2 Sensitivity to Gas Price

The other variable under control of GORTT through NGC is the gas price offered to the various projects. The potential impact of gas price variations is illustrated in the tables below which presents the gas prices required by the projects under the various fiscal terms to achieve a 12.5% real and 17.5% real rate of return. These results suggest that the shallow-water greenfield project will reach commercial rates of return under the recent PSC terms at gas prices between $5.05 and $6.42/Mcf, while incremental projects may require prices of between $3.44 and $4.63/Mcf.

Table 8-7 Gas Prices Required for 12.5% Real Return
(US$/Mcf)

Development	'96-05 PSC	Recent PSC	License
Incremental	4.36	3.44	4.44
Shallow Brownfield	2.58	2.05	2.77
Shallow Greenfield	6.41	5.05	6.16

Table 8-8 Gas Prices Required for 17.5% Real Return
(US$/Mcf)

Development	'96-05 PSC	Recent PSC	License
Incremental	5.86	4.63	5.80
Shallow Brownfield	3.18	2.43	3.27
Shallow Greenfield	8.09	6.42	7.42

8.1.4.3 Conclusions

The following conclusions can be drawn from the DCF analysis of generic project profiles under existing fiscal terms:

- For areas under 1996-2005 PSC or standard production license terms and with current average gas prices only the generic shallow-water brownfield development approached economic hurdles for sanction;
- The generic greenfield and incremental developments are likely to require both attractive fiscal terms (similar to recent PSCs) and higher gas prices than current average levels;
- Recently awarded PSC terms significantly reduce the gas price required to bring unsanctioned developments up to commercial returns compared to 96-05 PSCs or license terms.

8.2 MOBILISING SHALLOW-WATER UNSANCTIONED PROJECTS

8.2.1 Key Factors Influencing Project Sanction Economics

The production profiles presented in Section 7 identified that a significant proportion of gas volumes supporting the current production plateau beyond 2017 were reliant on planned but as yet unsanctioned projects being sanctioned and executed by the operators on their currently envisaged timelines. This requires that the as yet unsanctioned projects meet JV economic screening hurdles without any significant delay to ensure production commences within the anticipated schedule.

The capital cost of development plays a significant role in determining the economic attractiveness of a project seeking approval for execution. The analysis presented in section 8.1.4 identified the advantage enjoyed by projects utilising existing brownfield infrastructure, due to the lower capital cost incurred. Maximising access to ullage in existing facilities to assist development of additional reserves will expand the proportion of developments which can enjoy this advantage.

The analysis presented in section 8.1.4 suggests that 1996-2005 PSC terms with gas price indexing of profit gas splits will not support sanction of many of the developments required to maintain plateau production in the coming years. It also identified that existing production license terms would similarly struggle to support many new developments. These conclusions are based on assessment of generic development concepts with normalised license and PSC terms and while they are therefore not conclusive, it does provide some insight to the proportion of unsanctioned projects likely to proceed on their planned schedule. The proportion of unsanctioned projects which fall into these categories is illustrated in Figure 8-5.

Figure 8-5 Unsanctioned Projects by Fiscal Category

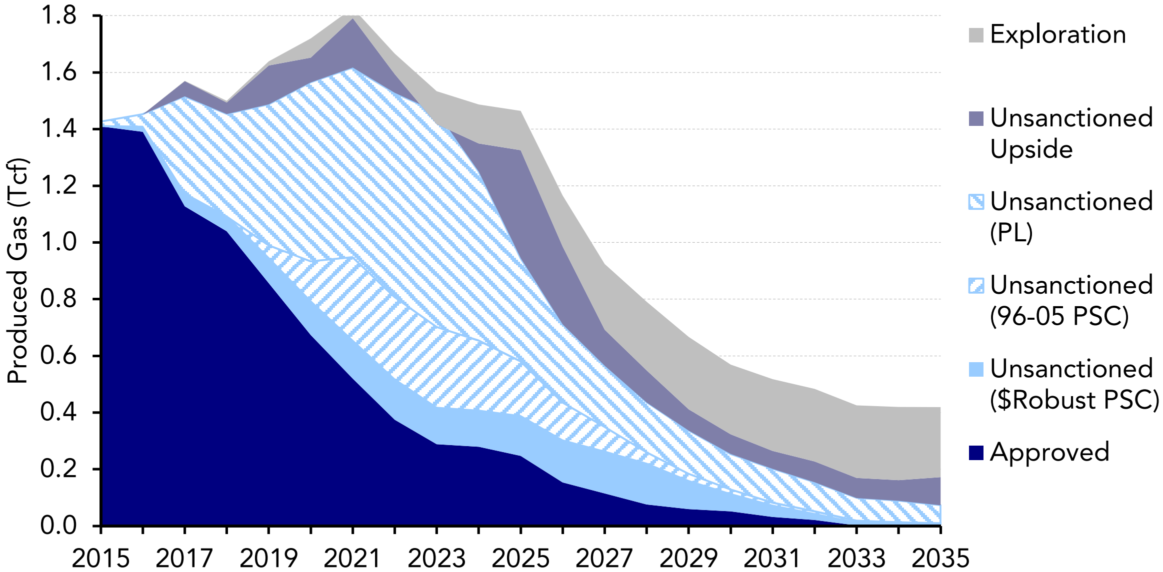


Figure 8-5 shows that a relatively small proportion (16%) of unsanctioned project volumes are located in PSCs with terms that are robust to current gas prices ($Robust PSC), being either PSCs issued in 2011-12 or earlier PSCs without gas price indexing of profit gas matrices. The DCF analysis suggests that these projects could reach economic screening hurdles with moderate flexibility on gas prices for developments carrying significant new infrastructure.

A slightly larger proportion (18%) of unsanctioned project volumes lie in 1996-05 PSCs with profit gas splits set in a low gas price environment and the majority of volumes (66%) sit in production license areas. The DCF analysis suggests that many of these projects will require some adjustment to their fiscal terms combined with flexibility on gas prices for developments carrying significant new infrastructure.

Regulatory intervention to stimulate marginal field development is not new to the oil and gas industry and may examples are available from other regions, a selection of which are documented in Appendix E. In general the measures fall into three categories, summarised in Table 8-9.

Table 8-9 Marginal Field Support Approaches

Option	Mechanism	Pros	Cons
Strictly Impose Relinquishment	Strictly apply relinquishment clauses. Refuse extensive appraisal periods. Re-bid to give low cost operators access to resources	Leverages existing contract terms Allows lower cost producers to access marginal acreage	Confrontational: State needs to collaborate with operators to manage gas supply State needs ability to manage total production – may need some gas deferral
Negotiated Support	Create a mechanism in which operators can request concessions on fiscal terms and gas pricing to allow projects to meet a defined commercial hurdle	Assistance is only provided to projects that need it and at the level required by the project	State needs capacity to analyse projects and negotiate with operators Potential for inconsistent treatment and gaming by operators
Marginal Field Fiscal Terms	Define category of fields which can access tax breaks / higher share of profit production	Provides clarity on incentives available and a consistent approach Low implementation burden on State	"Marginal field" difficult to define Step change in fiscal terms for marginal fields will encourage gaming by operators

The objective of marginal field intervention is to ensure that gas plateau production is extended as long as commercially reasonable and technically possible to maximise upstream revenue and support the downstream gas consuming industries. This requires both incentivisation of marginal fields and penalties for behaviours that do not support the production plateau on a basis that is transparent to all stakeholders.

Transparency requires a clearly defined and balanced environment for development of hydrocarbon resources, however the complexity of the mature shallow-water areas offshore T&T make application of a strictly formulaic approach problematic. An attempt to define which developments should receive marginal field incentives based purely on project characteristics will be challenged by the impact of brownfield infrastructure access and other project specific factors which influence economics. Similarly automatic and strict application of relinquishment terms may run counter to those objectives. However, to enhance transparency of the sector the default position of the regulator should be to enforce relinquishment terms unless specific arguments supporting short-term gas supply can be made to the contrary.

Maintenance of a plateau production rate of 1.4 Tcf/yr (3.85 Bcf/d) requires that a significant majority of unsanctioned projects proceed as planned. The preceding economic analysis would support a hybrid approach to this goal, consisting of an initial realignment of fiscal and other regulations to reflect maturation of the industry that has occurred over the last decade, combined with flexibility for the regulator to provide support to specific developments that cannot progress even under the revised terms

The initial realignment of regulations should include:

1) Maximising access for new developments to existing infrastructure to reduce costs.
2) Review and updating of fiscal terms in 1996-05 gas price indexed PSCs.
3) Review and updating of fiscal terms in in production license areas.

A transparent and easily administrated approach will also be required to the application of incentives for fields that remain marginal covering both additional fiscal support and flexibility in offered gas prices. Options to address points 1 – 3 above are explored in the following sections. Flexibility on gas price is considered in Section 12.

8.2.2 Access to Infrastructure

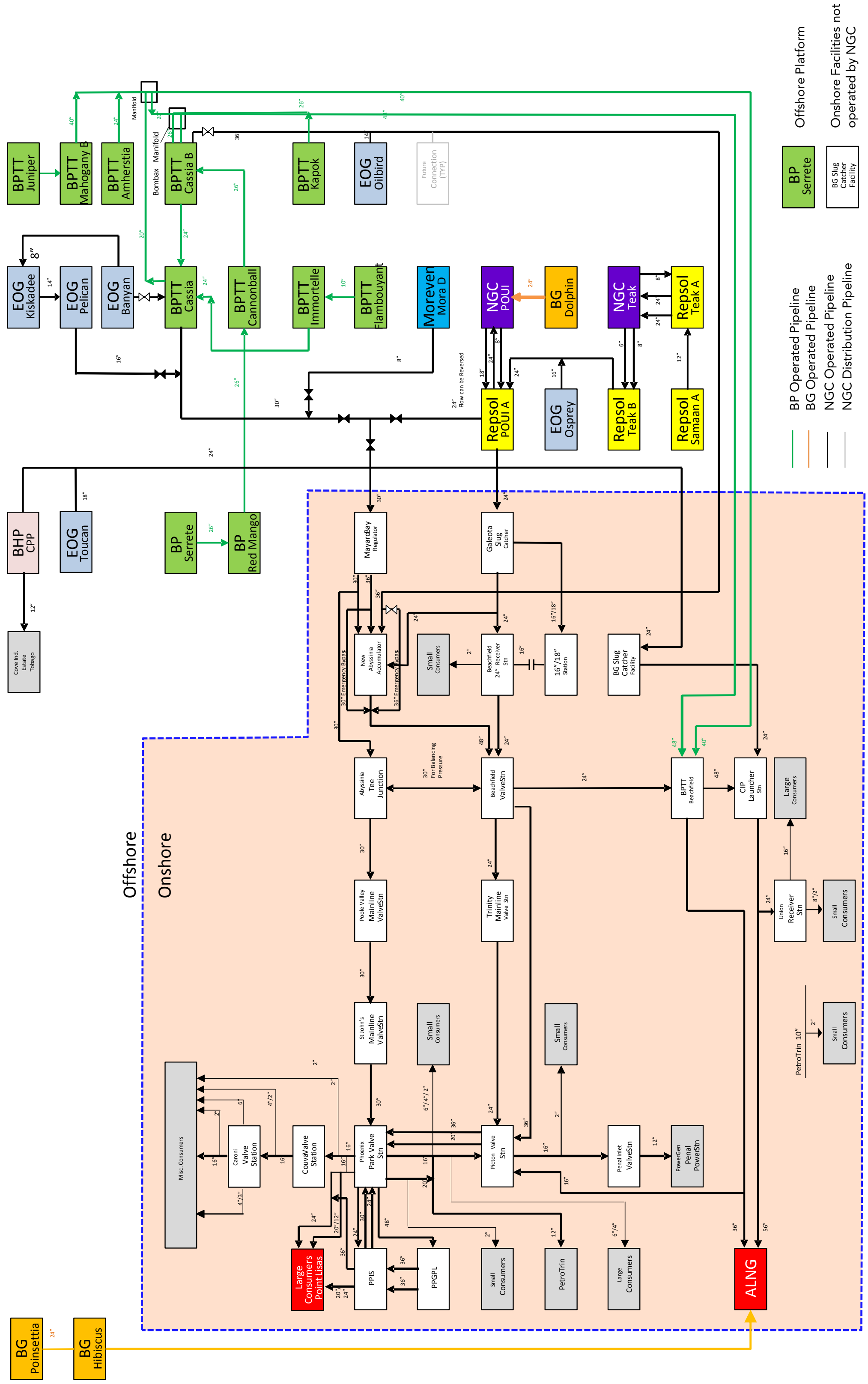
The analysis presented in Section 8.1.4 also identified the significant benefit accruing to projects which can utilise existing brownfield infrastructure. Depending on the size and type of project under consideration and the market it is targeting a project may benefit from access to:

- Offshore platforms
- Gas transmission lines
- Gas processing facilities

A detailed listing of pipeline sizes, capacities and ownership is presented in Section 4 of this report. A summary block diagram of gas production infrastructure and its ownership is presented in Figure 8-6. The following observations are drawn from this diagram:

- Gas platforms are all held by operators on behalf of the joint venture developing resources in that block.
- Gas transmission pipeline infrastructure is held by three main entities:
  - NGC operate pipelines down from Tobago via the BHP Angostura field, from the BG Dolphin complex in the eastern production area and from bpTT's Cassia complex in the south-east.
  - BHP, bpTT and BG operate several pipelines running in parallel to the NGC lines in the eastern and south eastern production areas.
  - Other operators operate standalone pipelines connecting their platforms into the production network, the longest of which is BG's 24" line from the Hibiscus field north west of Trinidad to the ALNG site.
- Process plants converting gas to internationally traded products such as LNG, ammonia and methanol are all held by private companies, with the LNG plant trains being owned by a consortia of E&P companies with NGC holding a small (10-11%) interest in each of Trains 1 and 4.

Figure 8-6 Overview of Gas Production Infrastructure



There are two criteria which must be met for a project to take advantage of existing infrastructure. Firstly sharing of infrastructure must be technically viable, including consideration of the required and available capacity of the infrastructure and compatibility of the produced fluids with the infrastructure design and existing hydrocarbon flows in the system. Secondly there must be mutually acceptable commercial terms agreed between the owner/operator of the infrastructure and the owner/operator of the project wishing to use that infrastructure. The data available for the Gas Master Plan was not sufficient to compile a complete picture of the demand for access to infrastructure, but some instances have emerged.

Examples of existing infrastructure sharing arrangements include gas from bpTT's EMZ field produced through the adjacent EOG Toucan platform with EOG also drilling the production wells. bpTT also make capacity in its offshore pipeline infrastructure available to NGC for transmission to the Beachfield terminal.

Table 8-10 Approaches to Improving Infrastructure Access

Option	Mechanism	Pros	Cons
Code of practice: voluntary – not legally binding (UK N Sea)	Owners publish tariffs and key terms and conditions Shippers negotiate with owners, but can apply to GORTT for a ruling if no agreement reached with owners	Can cover platforms and pipelines No legislation required Low cost approach	Needs clarity on coverage Protracted negotiations MEEA needs capacity to make rulings Smaller companies can face difficulties meeting larger company demands
Regulate access to infrastructure (Indonesia)	Legislate commercial terms for access to infrastructure by third parties. Access to all cost recovered infrastructure is on a shared opex basis	Simple and clearly consistent approach Maximises use of existing infrastructure	Would require a significant change to existing agreements and could be considered sovereign risk. May discourage installation of additional infrastructure
Transfer infrastructure to common carrier	Pipeline operation regulated by State Carriers allocates and expands capacity	Clear set of rules and tariffs	Only suitable for pipelines Significant upfront work required to establish system and operations Requires new legal/regulatory regime

However, there is demand for greater access by developers to third party infrastructure which will only increase as development of the shallow-water area continues to mature. The discoveries in NCMA 4 of the Orchid and Iris fields are struggling to move into development, partly due to their isolation from capacity in existing infrastructure, in this case constrained by an inability to secure capacity in BG's Hibiscus line and the low technical capacity of the NGC line from Tobago. In addition, the existing pipeline networks cross a significant number of open acreage blocks. Interest in exploring these areas would be increased if there was greater clarity on the terms of access to existing infrastructure in the event that exploration of those areas proves successful.

Access to attractive gas markets is also a key incentive for investment in exploration and development. This area is considered further in Section 12.

Upstream pipelines and offshore processing facilities are typically built by field owners to specifically process and transport production from their oil or gas fields. However, it advantageous both the other field operators and the GORTT to implement a regime allowing third-parties to use excess capacity. If the facility either: (1) is constructed with spare capacity; or (2) if spare capacity becomes available due to the decline in production, it is recommended that space is made available for use by third parties through a negotiated arrangement and payment of a tariff. This does not mean that pipeline systems are obligated to become common carriers, as is the case for oil pipelines in the U.S for example.

The challenge for the regulator is to create the conditions in which spare capacity in existing upstream infrastructure is made available to other developers under reasonable commercial terms to stimulate exploration and production investment. Approaches to this issue have been applied in other hydrocarbon producing countries, in particular Indonesia and UK North Sea (See Appendix E). The options available to the regulator fall in to three broad categories summarised in Table 8-10, together with their pros and cons.

Some counties such as Norway and Denmark have abandoned voluntary arrangements in favour of regulation. However, Poten proposes that a voluntary arrangement, similar to that implemented in the UK, Canada and the Netherlands should be adopted on the basis that it better suited to T&T's regulatory framework and market structure. The voluntary code of practice would be based on the following principles:

- Infrastructure owners provide transparent and non-discriminatory access
- Infrastructure owners provide tariffs and terms for unbundled services, where requested and practicable
- Parties seek to agree fair and reasonable tariffs and terms, where risks taken are reflected by rewards
- Parties publish key, agreed commercial provisions in a Commercial Code of Practice (CCoP)
- Parties provide meaningful information to each other prior to and during commercial negotiations
- Parties support negotiated access in a timely manner
- Parties undertake to ultimately settle disputes through the Automatic Referral Notice (ARN) process which involves MEAA's oversight.
- Parties resolve conflicts of interest by negotiation or dispute resolution procedures

Although the arrangements are settled at arms-length, the threat of government intervention is considered necessary in terms of ensuring that negotiations are conducted in good faith, which is the reason that the CCoP is to be adopted with the ability of disputes over the conditions of access to be submitted to MEAA for resolution. Poten is of the view that a voluntary gas pipeline access regime can be implement without legislation under the rule-making authority granted to the President either by direct regulation under Section 29 (1) (c), or by delegation to the Minister under Section 29 (1) (o) of the Petroleum Act.

The success of the relatively unintrusive UK North Sea approach of an Industry Code of Practise, supported by a regulator willing to intervene in the national interest in exceptional circumstances, presents a compelling model for T&T. The similarities in basin maturity and active operators to the North Sea, the need for a rapid (and therefore legally simple) solution and the desire to avoid perceptions of sovereign risk by radically rewriting existing arrangements all support this conclusion.

8.2.3 Potential Modifications to 1996-05 Gas Price Indexed PSCs

This section tests the impact of modifying 96-05 PSC terms with the intention of:

- Eliminating fiscal burdens from currently unsanctioned projects that were not intended or at least not the focus of discussions when the original terms were negotiated; and
- Testing the impact of extending fiscal relief offered to deepwater blocks to support marginal shallow-water projects.

The intention is not to proscribe the relaxation of fiscal terms across all developments in all PSCs, but to test the impact of making discrete modifications to PSCs within the range already considered elsewhere in T&T waters with the objective of determining the degree of flexibility that must be available to the regulator as it negotiates support for individual marginal shallow-water developments.

The analysis focuses on constraints on cost recovery and the matrix-determining split of profit production between GORTT and contractor, but does not explore changing the negotiated percentages in those matrices which were, together with the work programme, a primary element of the original acreage bid. Instead, modifications to cost recovery constraints and the price bands proscribed by GORTT in the original tender are considered together with treatment of total and incremental permit product and how it is applied to the matrix.

The review of PSC terms in section 8.1.3.1 identified the disparity in profit gas-sharing matrices and proposed an approach to normalising the gas price indexing of profit gas splits, illustrated in Figure 8-4. By resetting the gas price bands to current day gas price ranges, the developments will be subject to the profit gas splits intended at the time of PSC negotiation for gas prices which are high or low by current gas price standards. In addition the proportion of annual revenue available for cost recovery has been increased from the circa 55% in shallow-water PSC terms to the 80% level offered in deepwater PSCs.

The economic analysis presented in section 8.1.4 has analysed the incremental and brownfield projects as standalone cash flows in a given PSC. This would only be true if the development were leveraging infrastructure in an adjacent but separate block. The alternate and perhaps more likely scenario is that an incremental or brownfield project cash flow would be combined with cash flow generated by an existing project in the PSC. This would have two opposing effects:

1) Early costs would be recovered more quickly from the existing production base, increasing the incremental or brownfield NPV; and
2) The profit gas share to the contractor will be lower as the combined production from the existing and new projects moves into a higher production band in the profit gas split matrix, reducing the incremental or brownfield NPV.

A possible incentivisation to PSC terms, if required to support project sanction, would be to ring fence the new production from base production in the PSC, allowing the sharing of cost recovery with the base project but counting incremental / brownfield production separately when assessing the profit gas split from these projects.

The impact on project economics of adjusting gas price bands in the profit production matrix to reflect current pricing levels and varying the treatment of cost recovery ceilings and production accounting between base and incremental / brownfield projects is presented in the tables below.

Table 8-11 Contractor NPV12.5 with Varied PSC Terms ($3.1/Mcf Gas Price)

(US$ million, real)

Development	96-05 PSC	Recent PSC	Adjusted 96-05 PSC	Production Ring-fence
Incremental (standalone)	-86	-33	-38	
Incremental (w existing CF)	-38	23	41	71
Brownfield (standalone)	87	276	229	
Brownfield (w existing CF)	34	291	222	347
Shallow Greenfield	-537	-430	-347	

Table 8-12 GORTT Take with Varied PSC Terms ($3.1/Mcf Gas Price)

(US$ million, nominal)

Development	96-05 PSC	Recent PSC	Adjusted 96-05 PSC	Production Ring-fence
Incremental (standalone)	593	471	502	
Incremental (w existing CF)	577	431	517	378
Brownfield (standalone)	1,389	1,078	1,206	
Brownfield (w existing CF)	1,472	1085	1,350	1,064
Shallow Greenfield	1,066	835	742	

For all cases the adjusted 96-05 PSC terms deliver an economic outcome close to or better than 2011-12 PSC terms. This is a result of adjusting both the profit split matrix and increasing the cost recovery ceiling from 55% to 80% of production revenue. Comparison of Figure 8-3 and Figure 8-4 indicates that the revised profit-share matrix falls between the average of 2011-12 terms and the unadjusted 96-05 PSC terms. This adjustment, combined with acceleration of cost recovery, brings economic results close to the recent PSC terms. The adjustment of the profit-split matrix therefore represents a moderate improvement to the outdated 96-05 terms while staying within the range established by more recent 2011-12 PSC awards. Variation of cost-recovery ceiling provides an additional boost to economics where required by particularly challenged developments.

Including a base level of production cash flow in the analysis of incremental and brownfield projects tends to improve the NPV of poorly performing projects, but has little impact or reduces the NPV of profitable projects, without having a significant impact on nominal GORTT take. This is to be expected as high cost, poorly performing projects will gain more from the accelerated cost recovery offered by the base production, while in higher performing projects this will be balanced by the fall in profit gas share. The impact on GORTT revenue is predominantly one of timing, as cost recovery is accelerated, and total receipts are only impacted where the standalone project fails to recover all costs or where the change in profit gas share is significant.

Of greater relevance to the Master Plan is the impact on a marginal project located in a permit with existing cash flow when the new project's production is ring fenced for the purposes of assessing profit split. In this case the project benefits from accelerated cost recovery through the base cash flow, but the split of profit gas from the new project is assessed separately against only the new project's production level, avoiding the reduction in contractor share of profit gas due the base production moving the project into higher production bands in the profit gas split matrix. This drives contractor NPV above the level of even the most recent PSCs, but with a moderate reduction in total GORTT revenue.

8.2.4 Potential Modifications to the License Regime

This section tests the impact of modifying license terms by extending the fiscal relief offered to oil and condensate revenue and deepwater blocks to support marginal shallow-water gas projects. Again, the intention is not to prescribe the relaxation of fiscal terms across all developments in all licenses, but to test the impact of making discrete modifications within the range already considered elsewhere in T&T waters. The analysis focuses on providing tax relief to shallow-water gas projects but does not explore changing the royalty rates levied.

Under the Petroleum Taxes Act, discounted rates of PPT and SPT are applied to deepwater developments. SPT discounted rates are also available for new field developments, but as this tax is only levied on liquid production it is less relevant to the Gas Master Plan. We have used deepwater discounts on PPT to assess the impact of tax concessions already in place in the license regime on the generic projects described in section 8.1.1. We have also tested extension of the immediate depreciation of costs currently available for exploration spend to all development spend.

The resulting incentivised license terms are compared with the existing base license terms in Table 8-13, and results of DCF analysis are compared with the existing license terms and the performance under PSC terms in Table 8-14.

The analysis of existing PSC terms presented in section 8.1.4 identified that while the generic shallow-water brownfield development was fairly robust to current fiscal terms, the generic greenfield and incremental developments are likely to require both attractive fiscal terms similar to recent PSCs and higher gas prices to reach economic sanction levels.

Table 8-13 License and Incentivised License Key Terms

Fiscal Term	Base License	Incentivised License
Gas Royalty	5% (<100 MMcf/d) 10% (>100 MMcf/d)	5% (<100 MMcf/d) 10% (>100 MMcf/d)
Oil & Condensate Royalty	12.5% on all liquids	12.5% on all liquids
Supplemental Petroleum Tax	33% on liquids (>1500bbl/d) 25% on liquids (<1500bbl/d)	18% on liquids (deepwater terms)
Petroleum Profits Tax	50%	35% (deepwater terms)
Depreciation	Exploration is expensed Development at 50%, 30%, 20%	All costs expensed (Not currently available)

Table 8-14 Contractor NPV12.5 with Incentivised License Terms ($3.1/Mcf Gas Price)
(US$ million, real)

Development	96-05 PSC	Recent PSC	Adjusted 96-05 PSC	Existing License	Incentivised License
Incremental (standalone)	-86	-33	-38	-95	-46
Incremental (w existing CF)	-38	23	41	-39	26
Brownfield (standalone)	87	276	229	59	222
Brownfield (w existing CF)	34	291	222	87	303
Shallow Greenfield	-537	-430	-347	-466	-404

Table 8-15 GORTT Take with Incentivised License Terms ($3.1/Mcf Gas Price)
(US$ million, nominal)

Development	96-05 PSC	Recent PSC	Adjusted 96-05 PSC	Existing License	Incentivised License
Incremental (standalone)	593	471	502	632	517
Incremental (w existing CF)	577	431	517	628	528
Brownfield (standalone)	1,389	1,078	1,206	1,484	1,209
Brownfield (w existing CF)	1,472	1085	1,350	1,504	1,237
Shallow Greenfield	1,066	835	742	1,033	878

The DCF results presented in Table 8-14 and Table 8-15 show that the incentivised license terms bring project economics up to a similar level enjoyed by recent PSCs and the adjusted 96-05 PSC terms. This suggests that the tax relief provided in the incentivised terms will be sufficient to support sanction of many of the projects planned by operators which were shown to struggle under the existing license terms in the analysis presented in Section 8.1.4.

8.2.5 Fiscal Adjustments for Shallow-Water Areas

The significant volume of gas from unsanctioned projects forecast to support plateau production post 2017 can be categorized as:

- 66% is located in production license areas which will require adjustment of both fiscal terms and gas prices to support the full spectrum of likely gas developments.
- 18% is located in 1996-05 PSCs with profit gas splits set in a low gas price environment which will require adjustment of both fiscal terms and gas prices to support the full spectrum of likely gas developments.
- 16% is located in PSC's with terms that are robust to current gas prices and which could reach economic screening hurdles with moderate flexibility on gas prices for developments carrying significant new infrastructure.

Three broad approaches to modifying fiscal terms have been identified in Table 8-16. The approaches are graded by the extent of intervention required by the regulator and of the changes required to contractual terms. The boundary between minimal and moderate intervention is grey, moderate intervention is characterised by taking some proactive action on fiscal terms to reduce the number of projects which must be reviewed for a decision on case by case fiscal support.

Table 8-16 Approaches to Modifying Fiscal Terms

Option	Mechanism	Pros	Cons
Minimal Intervention	Only review fiscal terms where operator requests relief to support development	Minimises number of permits subject to fiscal changes. Avoids unnecessarily reducing GORTT take	Requires MEEA to review many requests for support: potential for delay. Inconsistent treatment of permits and operators
Moderate Intervention	Revise terms clearly incompatible with current industry environment e.g. PSC profit split pricing bands reset to current pricing levels	Simple (rapid), improves consistency of terms across shallow-water area Leaves split percentages bid by operators in place, preserving intent of bidders	May unnecessarily reduce GORTT take in some projects
Deep Intervention	Revise all PSC and license terms to a new common basis	Ensures all reserves have an equal fiscal basis for development	Wholesale change may be challenged by incumbents Eliminates basis on which permit was won

Preliminary analysis suggests that revision of existing 1996-05 PSCs with gas price indexing of profit-split matrices, by revising the profit-split matrix gas price bands to a range of \$3.00/Mcf to \$7.00/Mcf will provide a necessary boost for incremental / brownfield development projects at moderate impact to GORTT revenue. Offering these terms for new and incremental developments in the affected blocks is a good candidate for proactive adjustment of fiscal terms, moving the recommended response at least into the moderate intervention band. A more detailed review of planned projects should be undertaken to determine whether relaxation of PSC cost-recovery terms should be included in this proactive step or applied only under negotiation of specific developments.

The need for support of projects under existing license terms is also clear, but again further review of planned projects would be required to recommend the support that should be offered proactively across all license areas, rather than on a case-by-case basis. An intermediate step of reducing Petroleum Profit Tax on new field developments in the Production License areas would greatly reduce the workload of project review on the ministry and provide a significant incentive for license holders to explore for and develop remaining gas fields in their concession areas.

The need for a rapid (and therefore legally simple) solution and the desire to avoid perceptions of sovereign risk by radically rewriting existing arrangements suggest that wholesale change to fiscal terms in a deep intervention approach would not be appropriate.

The moderate intervention approach will require transparent definition of the support available through negotiation with the regulator to encourage developments which otherwise will not meet economic screening hurdles. Such support would include:

- Depreciation schedules in both licenses and PSCs and cost-recovery caps in PSCs.
- In PSCs with existing production consider ring-fencing production from incremental projects to improve contractor profit gas splits which maintain shared cost recovery.

- In production licenses consider applying tax breaks similar to those available for deepwater developments.
- Allocation of preferential gas prices to marginal developments.

The requirement to actively support marginal projects through the sanction process by allocating fiscal relief and / or preferential gas prices where they are required by each individual project will place a significant burden on the regulator. Currently the regulator has been required to implement only a single set of fiscal terms for each permit and has been able to operate largely separately from the gas price negotiations managed by NGC. The challenge for the regulator will be to apply additional support only to those projects that need them, in collaboration with gas price negotiations by NGC and in a timeframe which does not delay the orderly sanction and execution of gas supply projects required to maintain plateau production.

8.3 MOBILISING DEEP WATER GAS

Section 7.3 of this report identified that production from discovered and prospective shallow-water resources has the potential to maintain plateau production at 3.85 Bcf/d until 2025, after which production would decline from this area. Deepwater gas from the current exploration programme is identified as a potential source of supply to backfill the shallow-water production profile, and extend the plateau production out towards 2030. The viability of this scenario is entirely dependent on exploration success in the upcoming mid-2016 drilling campaign and on the size and production characteristics of any discoveries made.

This section considers the economics of a typical greenfield deepwater development based on development cost and production profiles provided by operators to assess the gas prices likely to be required by a deepwater discovery.

The generic concept adds ~3,700 Bcf of gas and ~92 MMbbl of condensate (CGR=25 bbl/MMcf) from a greenfield deep water development. The significant field size and high condensate ratio have been selected to reflect the larger, richer field characteristics required to justify appraisal and development in deep water. The economies of scale reduce the undiscounted pre-tax total cost to ~$2.50/Mcf, however production does not commence until year 9 of the cashflow model, reflecting extensive pre-FID and execution phase durations for a complex deepwater development.

Deepwater areas have all been awarded as PSCs and while Poten has access to the model PSC form from previous bid rounds we have not been provided with the agreed terms of profit production split for awarded deepwater blocks. We have therefore applied recent PSC and adjusted PSC terms from the shallow-water analysis to provide a comparison with those developments and an initial assessment of required gas prices.

The DCF results are compared with those from the shallow-water greenfield concept in Table 8-17.

Table 8-17 Deepwater Greenfield Project Economics

	Units	Shallow Greenfield		Deepwater Greenfield	
		Recent PSC	Adjusted 96-05 PSC	Recent PSC	Adjusted 96-05 PSC
Contractor Real IRR @ $3.10/Mcf	%	-0.6%	1.4%	8.5%	7.3%
GORTT Take @ $3.10/Mcf	$MM	840	740	8,500	9,900
Gas Price for Real IRR = 12.5%	$/Mcf	5.05	5.45	4.57	6.21
Gas Price for Real IRR = 17.5%	$/Mcf	6.42	7.35	7.08	9.45

At a gas price of $3.10/Mcf the deepwater generic project fails to reach screening criteria under either recent PSC or adjusted 96-05 PSC terms. The deepwater project has a lower unit technical cost (undiscounted capex + opex) of $2.50/Mcf than the shallow-water greenfield project ($3.30/Mcf), driven by the economies of scale on a project with a five times larger reserve base. The larger volumes, lower unit technical cost and higher condensate gas ratio deliver a higher rate of return than the greenfield project at the $3.10/Mcf gas price and a GORTT take circa ten times greater.

The longer development duration of the deepwater development drives a wider range of gas prices required to meet the screening thresholds considered. Under Recent PSC terms the deepwater project would require between $4.57 and $7.08/Mcf, compared to $5.05 to $6.42/Mcf for the shallow-water project. Provided the actual PSC terms agreed with contractors are at least as attractive as recent shallow-water PSCs and provided commensurately attractive gas prices can be delivered then it would be reasonable to expect that a large (>3 Tcf recoverable) and relatively condensate rich (25 bbl/MMcf) discovery would be developed.

The key challenge for T&T is to incentivise enough exploration activity in deep water blocks in an early enough timeframe to ensure that any gas present is developed in time to backfill the shallow-water production profile.

Currently only 1/3 of deepwater blocks have been licensed and 8 exploration wells committed in the first term work programmes. These wells will be drilled in a campaign commencing mid-2016. However, with a nominal probability of success of <20% it would be reasonable to expect only one discovery from the committed programme which may not be gas bearing given that contractors are incentivised to pursue oil prospects over gas due to the superior economics of smaller discoveries. Success in the first work period would encourage operators to pursue subsequent phases but current contracts would deliver a maximum of only 22 wells over the full exploration program.

The focus for T&T at this stage should be to expand the number of blocks under license with firm drilling commitments. This will be challenging in the current environment of reduced expenditure across international oil and gas companies, however opportunities for stimulating increased activity should be explored including:

- State-sponsored seismic acquisition.
- Review of fiscal terms and alignment between GORTT and operator incentives.
- Road shows to advertise new fiscal terms and seismic data.

8.4 MOBILISING CROSS-BORDER GAS

Section 7.4.2 of this report identifies development of gas reserves straddling the maritime border with Venezuela as a potential source of gas to backfill the shallow-water production profile and extend the plateau production out towards 2030. The discovered volumes and recent announcements on the progress of discussions between Venezuela and T&T on development of those fields are summarised in Section 7.4.2.

Supply from the cross-border fields relies on the outcome of government to government discussions which have been in progress for many years. Only 27% of the largest field (Manatee Loran) lies in T&T waters but for any significant extension of plateau production the entire field would need to be processed through T&T infrastructure.

The challenge therefore is two-fold:

- Stimulate progress in the long running inter-government discussions.
- Incentivise Venezuela to develop the entire field through existing T&T infrastructure.

Progress over the years has been slow and politically contentious in both countries. In the past there has been limited urgency in T&T to proceed due to ample gas supplies. However, the emergence of gas supply shortages in recent years, together with the understanding that even the current reduced production plateau will not extend beyond 2025 has provided a clear imperative for T&T to progress these discussions towards an agreement to develop the gas. There is a window of opportunity to process gas through existing consumers as shallow-water gas production declines in the mid-2020s.

While it is understood that the nature of these negotiations will be complex, it is recommended nonetheless that further initiatives are taken, including:

- Setting clear deadlines and timelines within GORTT for progress of the discussions with Venezuela.
- Comprehensive evaluation of the value to T&T of securing an arrangement whereby 100% of produced gas is processed through their existing infrastructure, to allow specific value propositions to be formulated and when appropriate presented to the Venezuelan government.
- Consideration of how agreement to develop the gas reserves could form part of a broader bilateral agreement with Venezuela.

9.1 DOWNSTREAM PORTFOLIO

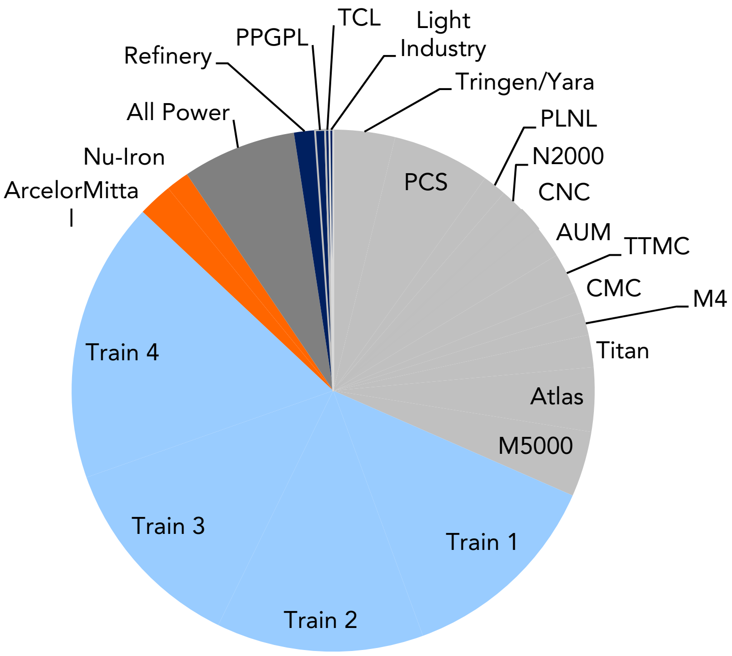
9.1.1 Overview

The existing downstream gas consumption portfolio consists of LNG, ammonia (and derivatives), methanol, iron and steel, power and other industries (which includes supply to TCL (cement), the refinery, PPGPL (gas processing) and small consumers). The portfolio could consume up to around 4.3 Bcf/d of gas at full capacity utilisation.

As shown in the figure below, LNG dominates the downstream portfolio and at full capacity utilisation would account for around 55% of total consumption. Petrochemicals are also significant gas consumers with ammonia (and derivatives) and methanol at 16% and 15% of total demand respectively. The power sector accounts for around 7% of demand with other buyers accounting for around 2% (refinery, gas processing, cement, light industries). It should be noted that these figures exclude internal upstream consumption / reinjection, which based on historical data has averaged around 7% of gross production in T&T.

Figure 9-1 The Existing T&T Downstream Portfolio

(Source: MEEA, NGC, ALNG)



These downstream industries are discussed in greater detail in the remainder of this section.

An assessment of gas utilisation options is provided in Appendix F.

9.1.2 LNG

9.1.2.1 Current Portfolio

The ALNG plant at Point Fortin is by far the largest consumer of gas in T&T; it account for around 58% of gas consumption in 2014. The table below shows the consumption by train based upon the maximum gas consumed in the period since 2010 (Max Gas) and currently contracted daily quantity (DCQ) (except for Train 4 which is a tolling facility).

The plant consists of four liquefaction trains with total capacity of 14.8 million tonnes per year (MMt/y). The train sizes for plants 1-3, as shown in the table below, are relatively small by today's standard for greenfield plants, which are commonly of 4.5-5.0 MMt/y. Train 1 delivered its first LNG in April 1999, followed by Train 2 in 2002, Train 3 in 2003 and Train 4 in 2005. Train 4 was the world's largest when it was completed.

The main ownership players are BP, BG and Shell, which each own significant stakes in each of the four trains. GORTT (via NGC/NEL) owns a minority stake in Trains 1 and 4.

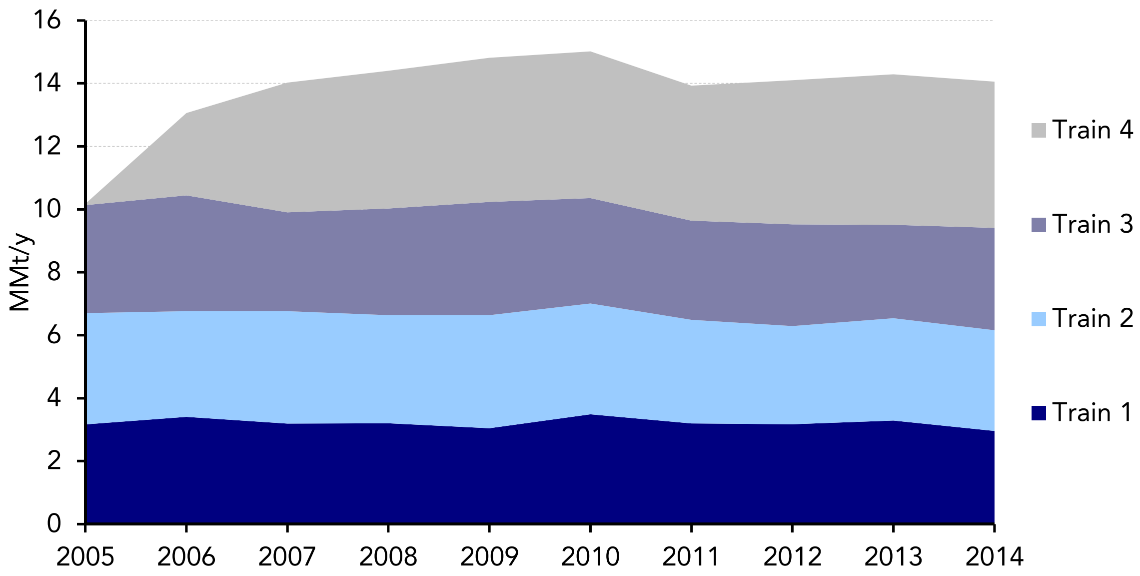
Table 9-1 T&T LNG Trains

(Source: MEEA, ALNG)

Plant	Owner	Capacity MMt/y	Start Up	Max Gas MMcf/d	DCQ MMcf/d	Contract Expiry
Train 1	BP (34%), BG (26%), Shell (20%), NGC TT LNG (10%), CIC (10%)	3.0	1999	548	442	2019
Train 2	BP (42.5%), BG (32.5%), Shell (25%)	3.3	2002	547	510	2022
Train 3	BP (42.5%), BG (32.5%), Shell (25%)	3.3	2003	528	517	2023
Train 4	BP (37.8%), BG (28.9%), Shell (22.2%), TTLNG (11.1%)	5.2	2005	743	N/A#	2025
Total				2,366	1,469	
#Tolling facility						

As shown in Figure 9-2, since the ramp up in 2006/7 production following the start up of Train 4, ALNG's total production has been maintained in the 14-15 MMt/y range. However, production has declined from a peak of around 15.0 MMt in 2010 to around 14.0 MMt in 2014, representing a decline from peak of around 6.4%, as declining gas supply availability restricted production to an extent.

Figure 9-2 T&T Historic LNG Production
(Source: MEEA)



However, production declines have not been distributed equally across all trains. 2014 production below peak was as follows:

- Train 1: 15.1%
- Train 2: 11.0%
- Train 3: 11.7%
- Train 4: 2.9%

9.1.2.2 New Project

A Project Development Agreement was signed in January 2015 between GORTT, NEC, Gasfin and Caribbean LNG regarding the development of a mid-scale, 0.5 MMt/y LNG plant at La Brea ("Caribbean LNG"). Caribbean LNG is intended to supply the regional rather than the global LNG market. The project is expected to consume 75 MMcf/d of gas from 2019.

9.1.3 NGC-Supplied Industries

Each of the non-LNG gas consumption sectors are supplied with gas by NGC. The individual sectors are discussed below.

9.1.3.1 Ammonia

Since the first ammonia plant in T&T was commissioned in 1959, production capacity has grown to around 6 MMt/y from 11 plants, as shown in Table 9-2.

The first plant (Yara) was started up in 1959 by WR Grace Co. and was acquired by Norsk Hydro Agri in 1991. Norsk Hydro decided to list Agri as a separate company, Yara, on the stock exchange in 2004. Yara, in partnership with GORTT (via NEL), is also the owner of the first ammonia complex in T&T, which comprises the two Tringen plants which started up in 1977 and 1988.

The second complex, which is owned by Potash Corporation of Saskatchewan (PCS), comprises four ammonia plants and one urea plant. The first two plants (and the urea plant) which started up in 1981 were originally owned by GORTT and Amoco (now BP). GORTT sold its stake to Arcadian in 1994, a third plant was commissioned in 1997 and the entire complex was sold to PCS in 1997 before a fourth plant was commissioned in 1998.

The PLNL, CNC and N2000 plants were added between 1998 and 2004, while the latest plant, AUM, was commissioned in 2009.

Table 9-2 T&T Ammonia Plants

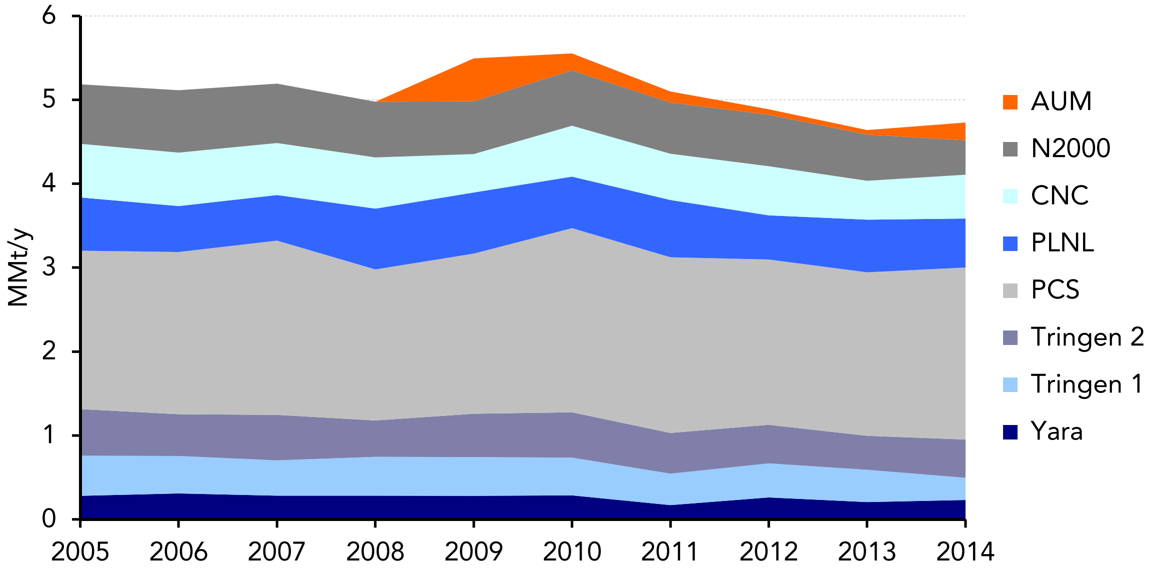
(Source: NGC)

Plant	Owner	Capacity MMt/y	Start Up	Max Gas MMcf/d	DCQ MMcf/d	Contract Expiry
Tringen 1	NEL (51%), Yara (49%)	0.5	1977	62.5	54.2	End 2019
Tringen 2	NEL (51%), Yara (49%)	0.5	1988	54.0	51.3	End 2019
Yara	Yara	0.285	1959	40.2	39.0	End 2019
PCS 1&2	PCS	0.89	1981	120.9	121.0	End 2018
PCS 3	PCS	0.25	1996	42.2	40.7	End 2018
PCS 4	PCS	0.65	1998	80.3	69.7	End 2018
PLNL	Koch (50%, Terra Industries (50%)	0.65	1998	62.6	62.0	End 2018
N2000	Proman, EOG, Koch	0.65	2004	64.0	58.1	End 2019
CNC	Proman, EOG, Koch	0.65	2002	64.3	58.1	End 2017
AUM	CEL	0.77	2009	80.9	84.2	End 2027
Total		6.0		672	656	

Similarly to LNG, T&T's ammonia production has declined since reaching peak production in 2010 (5.6 MMt), as shown in the figure below. Production in 2014 was 4.7 MMt. However, the decline from peak production at 14.8% has been significantly higher than the 6.4% for LNG.

Figure 9-3 T&T Historic Ammonia Production

(Source: MEEA)



Production declines have varied significantly across different plants. 2014 production below peak was as follows:

- Yara: 25.0%
- Tringen 1: 44.7%
- Tringen 2: 18.0%
- PCS: 6.5%
- PLNL: 20.0%
- CNC: 18.1%
- N2000: 45.0%
- AUM: 58.3%

9.1.3.2 Methanol

Current Portfolio

There are currently seven methanol plants in operation in T&T with a combined capacity of around 6.6 MMt/y as shown in the table below.

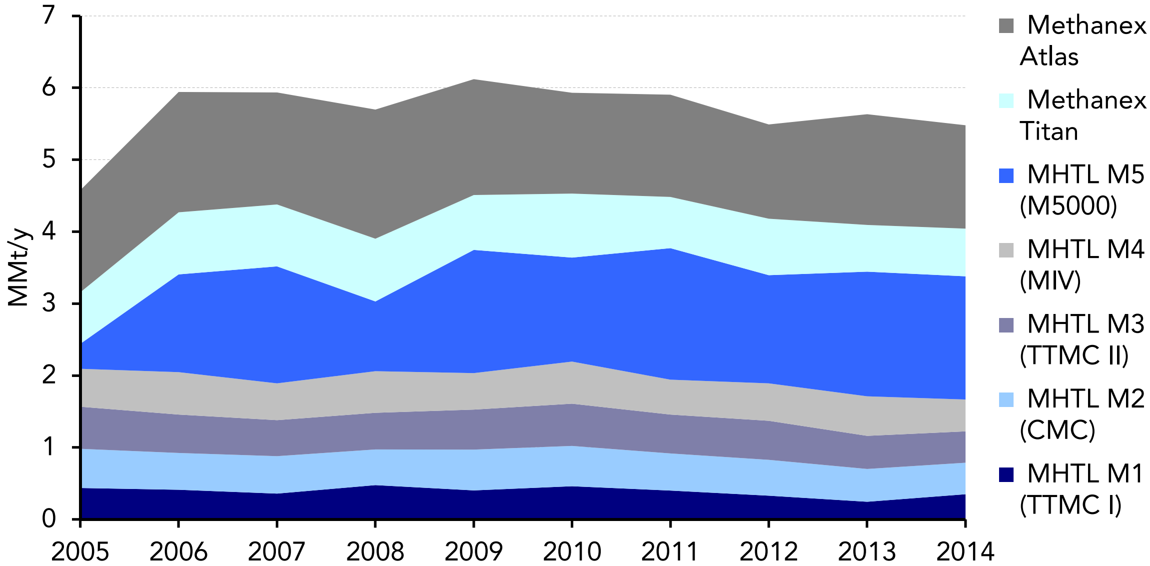
Table 9-3 T&T Methanol Plants
(Source: NGC)

Plant	Owner	Capacity MMt/y	Start Up	Max Gas MMcf/d	DCQ MMcf/d	Contract Expiry
TTMC 1	MHTL	0.48	1984	107.9*	104.3*	End 2015
TTMC 2	MHTL	0.57	1996			End 2015
CMC	MHTL	0.55	1994	55.9	48.4	End 2015
MIV	MHTL	0.58	1998	60.6	56.1	Expired
Titan	Methanex	0.85	1999	85.1	77.4	End 2019
Atlas	Methanex (63.1%), BP (36.9%)	1.7	2004	169.6	164.0	End 2024
M5000	MHTL	1.89	2005	173.0	164.6	May 2020
Total		**6.6**		**652**	**614**	
	* Covers TTMC1 & 2					

The first plant, T&T Methanol Company (TTMC), started up in 1984. TTMC 2 was commissioned in 1996. TTMC was formely GORTT-owned but is now owned by Methanol Holdings Trinidad Ltd. (MHTL). MHTL also owns the second plant, Caribbean Methanol Company (CMC), which started up in 1994, the fourth plant, Methanol IV (MIV), which started up in 1998, and the seventh and largest plant, M5000, which started up in 2005. The remaining two plants are controlled by Methanex: Titan (1999 start up) and Atlas (in partnership with BP, 2004 start up). Atlas and M500 are two of the largest methanol plants in the world.

As shown in Figure 9-4, methanol production has followed a similar trajectory of late to that of LNG and ammonia, declining by around 10.4% from a peak of 6.1 MMt in 2009 to 5.5 MMt in 2014.

Figure 9-4 T&T Historic Methanol Production
(Source: MEEA)



Again, production declines have varied significantly across different plants. 2014 production below peak was as follows:

- TTMC 1: 26.6%
- CMC: 22.8%
- TTMC 2: 25.8%
- MIV: 24.8%
- M5000: 6.3%
- Titan: 25.5%
- Atlas: 20.0%

Clearly gas supply to M5000 has been prioritised over supply to the other plants, which have seen much larger (and similar) cuts to their gas supply.

New Project

Mitsubishi signed a Project Agreement with NGC and Massy Holdings in April 2015 regarding the development of a new methanol and dimethyl ether plant at La Brea. Contracts for EPC, gas supply and land leases have also reportedly been concluded. The project is expected to consume 100 MMcf/d of gas under a 15 (+5) year contract from 2019.

9.1.3.3 Power Generation

All of T&T's electricity is currently generated from natural gas. The government is, however, planning changes to legislation that will support electricity production from renewable energy sources. T&T has 2,155 MW of installed capacity as shown in Table 9-4.

Table 9-4 T&T Power Plants
(Source: NGC/MEEA)

Plant	Owner	Capacity MW	Start Up	2014 Gas Supply MMcf/d	Contract Expiry
Point Lisas	Powergen	635	1977		
Port of Spain	Powergen	290	1965		
Penal	Powergen	210	1953		
Point Lisas	Trinity Power	225	1999		
La Brea	Trinidad Generation Unlimited (GORTT 100%)	720	2012		
Cove Estate	T&TEC	64	2013		
Scarborough	T&TEC	11			
Total		**2,155**		**301***	**No contract in place**
*Max delivered to T&TEC by NGC. All gas for power delivered to T&TEC					

The power sector in T&T remains predominantly state-owned, despite attempts over the years to increase private sector participation through Independent Power Producers. T&T has three power generating companies – Powergen (majority owned by T&TEC), Trinity Power Limited and Trinidad Generation Unlimited (GORTT-owned) – and the T&T Electricity Commission (T&TEC), which is responsible for transmission, distribution and sales (retail). T&TEC buys power from the generating companies, which it transports and sells to electricity consumers.

There is no formal contract with T&TEC to supply gas into power generation, and it is understood that the last contract expired around 1995. Consequently there is no formal DCQ/ACQ volume commitment to T&TEC.

9.1.3.4 Iron & Steel

There are two iron/steel complexes in operation in T&T, as shown in the table below: ArcelorMittal and Nu-Iron. ArcelorMittal Point Lisas' principal production facilities comprise three direct reduced iron (DRI) plants, two electric arc furnaces, two continuous casters for billets and one wire rod mill. In 2013, ArcelorMittal Point Lisas produced 0.6 MMt of crude steel. Nucor's Nu-Iron DRI plant started up in 2007 with an annual production capacity of around 2 MMt.

Table 9-5 T&T Iron & Steel Industries

(Source: NGC, ArcelorMittal)

Plant	Owner	Start Up	Max Gas MMcf/d	DCQ MMcf/d	Contract Expiry
ArcelorMittal I&II	ArcelorMittal	1980-2	42.3	37.0	Expired
ArcelorMittal III	ArcelorMittal	1999	47.8	53.2	Expired
Nu-Iron	Nucor	2007	62.2	60.5	End 2027
Total			**152.3**	**151**	

9.1.3.5 Other

The other consumers of gas in T&T are summarised in the table below.

Table 9-6 Other Consumers

(Source: MEEA)

Plant	Owner	Gas Supply / DCQ MMcf/d	Contract Expiry
Refinery	Petrotrin	55	No contract
PPGPL	PPGPL	26	
TCL	TCL	11	Expired
Light Industry	Various	10	Various
Total		**102**	
*Major expansion in 1960			

The supply situation to the Petrotrin refinery is similar to that of T&TEC. There is no formal contract in place as the last one expired around 1999.

9.1.4 Demand Summary

As can be seen from Table 9-7, the downstream gas-based portfolio could consume up to around 4.3 Bcf/d of gas at full capacity utilisation.

Table 9-7 Summary Gas Consumption

Plant	Max Gas MMcf/d	DCQ MMcf/d
Ammonia/Urea	696	658
Methanol	652	558
LNG	2,366	2,212*
Iron & Steel	151	60.5
Power Generation	301	301#
Other Industries	102	91#
Total	**4,268**	**3,881**

*Includes Train 4 volumes
#Assume same as Max Gas

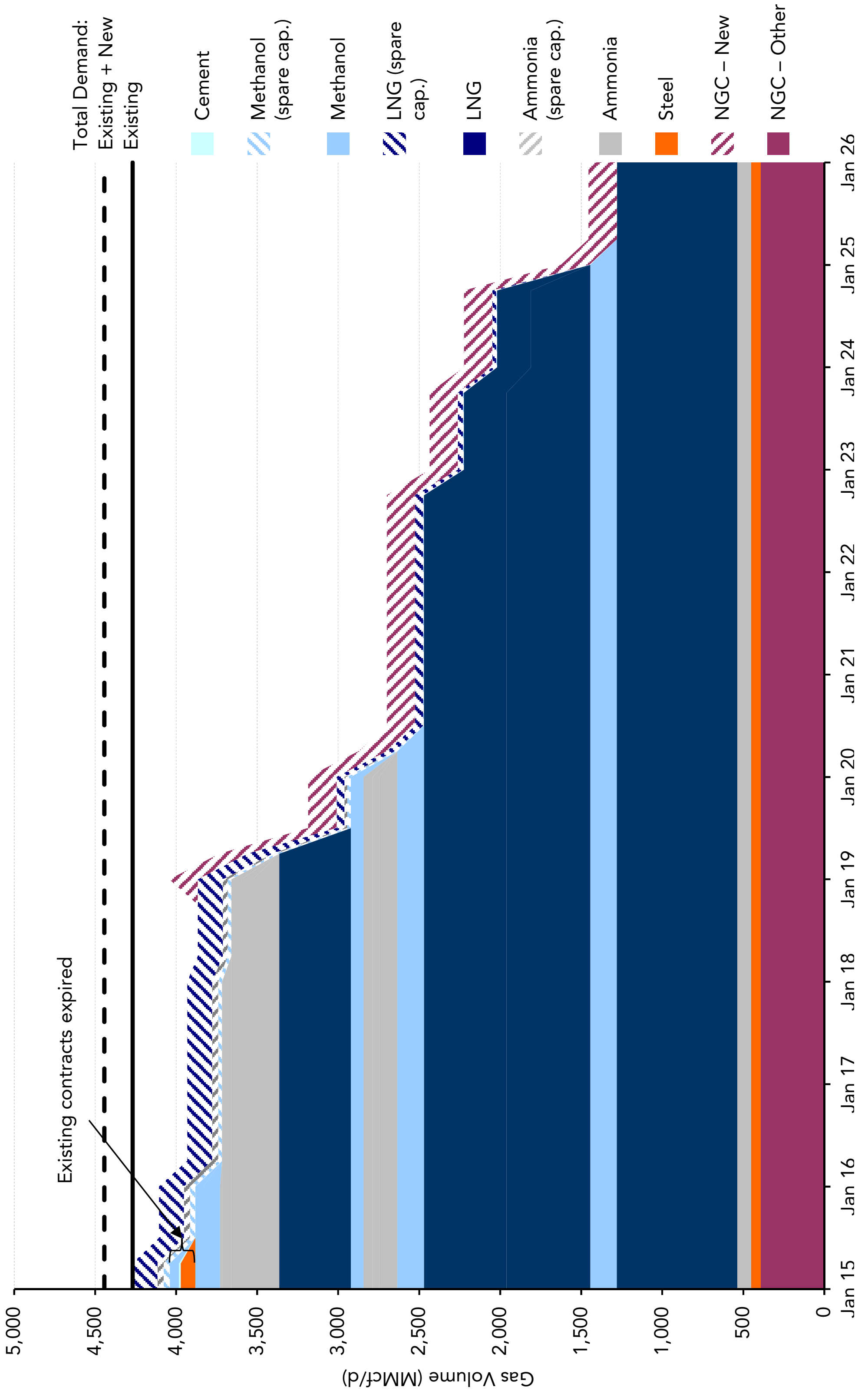
Figure 9-5 shows the evolution of contracted gas demand over the Master Plan period, as well as total demand. "Existing + new" demand includes the new "mid-scale" LNG plant and new methanol plant described previously. Where contracted quantities are less that maximum gas consumption of the plant we have labelled this difference as "spare" capacity. The analysis assumes that NGC supply to power generation and other industries continues at 2014 levels.

Of the maximum existing gas demand figure of 4,268 MMcf/d, spare capacity and contracts that have already expired (MIV (methanol), TCL (cement) and ArcelorMittal (iron/steel)) account for 387 MMcf/d, giving a figure for current downstream contracted gas demand of 3,882 MMcf/d. This figure will decline to 3,718 MMcf/d by the end of 2015 with the expiry of the contracts to supply CMC (methanol), TTMC (methanol) and PCS Urea.

Many contracts expire in the 2018-2020 period, including ALNG Train 1, all of the remaining ammonia plants with the exception of AUM, and all of the remaining methanol plants with the exception of Atlas. Post-the expiry of these contracts the level of contracted gas demand will drop to 2,471 MMcf/d, or 2,646 MMcf/d if the combined 175 MMcf/d of supply to the new LNG and methanol projects is included.

In general, when downstream supply contracts have expired NGC has been extending them for 5 year terms.

Figure 9-5 Contracted Gas Demand for Master Plan Period



9.2 DOWNSTREAM MARKETS & PRODUCT PRICING

9.2.1 Overview

T&T has developed a major gas export industry both directly, in the form of LNG, and indirectly through gas-based petrochemicals (ammonia/urea, methanol). The sale of these products collectively account for ~80% of the gas consumption in T&T. T&T's competitive advantage in addressing these markets has been the low cost of the gas resource and the proximity to the world largest market, the US, which was short on gas supply and had significant demand for LNG and gas-based petrochemicals. These competitive advantages have eroded over time. Incremental gas supply from T&T reserves will be more expensive to develop and the US market is now saturated with gas, bolstered by the rapid growth of shale gas which can be developed at relatively low cost, as a result of which the US is looking to become a major LNG exporter in direct competition with T&T. As T&T gas products are pushed out of the North American market they will have to travel further to reach new markets which will add to logistics costs and reduce competitiveness.

T&T exports are now competing for market share against products from other supplier countries on price. T&T has a competitive edge predominantly to the extent that indigenous resources can be developed and delivered to market at lower cost than those of competitors. Pricing for LNG is not within the control of T&T but the value extracted for the benefit of the country will depend on the efficiency of the value chain and the cost of exploiting the gas. In petrochemical markets feedstock and logistic costs are a key competitive advantage. Understanding the new sources of supply and their cost position is important in determining present and future competition and potential target markets.

Many of the large global reserve holders have insufficient gas/high domestic demand which will preclude them from developing export projects (Saudi Arabia, UAE) and others have locational challenges to reach export markets (Turkmenistan, Russia). In addition to North American producers, it will be the newer areas such as Mozambique and Tanzania that pose more of a threat to T&T in the long run.

The development of gas markets in Europe is driving an evolution in gas pricing, with a shift away from oil-linked pricing to hub-based pricing. This has an impact beyond Europe as this market has become the market of last resort for LNG and thus has become an important marker in the LNG spot market pricing. It is the dynamics of European gas supply and demand which are setting prices rather than the price of oil or its related products.

LNG is linking what have traditionally been compartmentalised regional gas markets. Although LNG trade is relatively small compared to overall gas consumption, it links markets in a more dynamic way than pipeline gas and opens the world to gas supply on different commercial terms. The introduction of significant volumes of LNG priced on a US market (HH) basis combined with the recent oil price drop has increased the options for gas buyers across the world.

The individual markets segments are discussed further below and in greater detail in Appendix H. An assessment of the global economic outlook and associated energy trends is also provided in Appendix G.

9.2.2 LNG

9.2.2.1 Market Overview

Natural gas is unique in the global energy mix: it is a globally abundant and commercially viable hydrocarbon combining the reliability of other fossil fuels such as coal and oil with a relatively low carbon footprint and low emissions. Combined cycle gas turbines (CCGTs) represent the most efficient power generation technologies, in terms of production and capital cost requirements, with a flexibility that makes gas an ideal back-up solution for the intermittence of renewables, such as wind or solar.

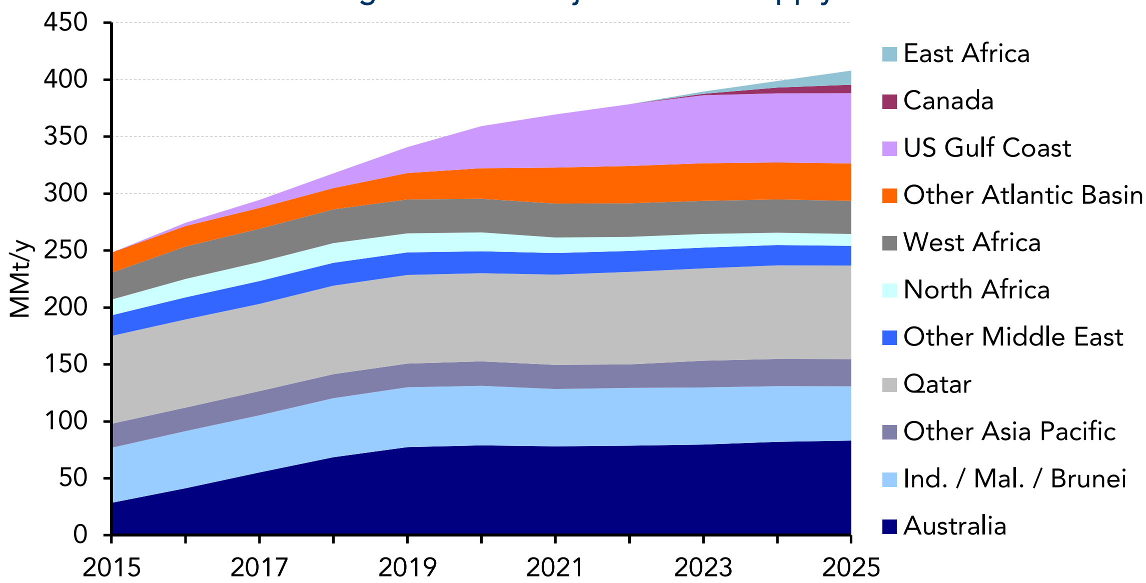
Natural gas is projected to expand its share of the global TPES, a trend that is already underway in many key regions. Poten's base projection shows the percentage share of TPES held by natural gas growing to 23% by 2025 from 21% in 2013. These figures are in line with the IEA long-term view which has natural gas increasing its share of global TPES in all its scenarios.

From 2000 through 2014, the number of countries producing LNG increased from 12 to 19. LNG exports more than doubled over this period from 113.6 MMt in 2000 to 243.8 MMt in 2014, driven in part by export growth in Qatar. In 2000, Qatar exported approximately 12 MMt, or approximately 10% of global exports; by 2014, Qatar exported 77.2 MMt, or nearly one-third of global exports with production spurred by the building of six 7.8 MMy/y "mega-trains", the biggest ever built.

Liquefaction plants located in the Atlantic Basin made up around 23% of global LNG production in 2014 (around 6% of which came from T&T) with Middle Eastern production accounting for 40% and Asia-Pacific the remaining 37%.

Based on projects currently being undertaken Poten forecasts LNG production will reach ~400 MMt/y by 2025, as shown in the figure below.

Figure 9-6 Projected LNG Supply



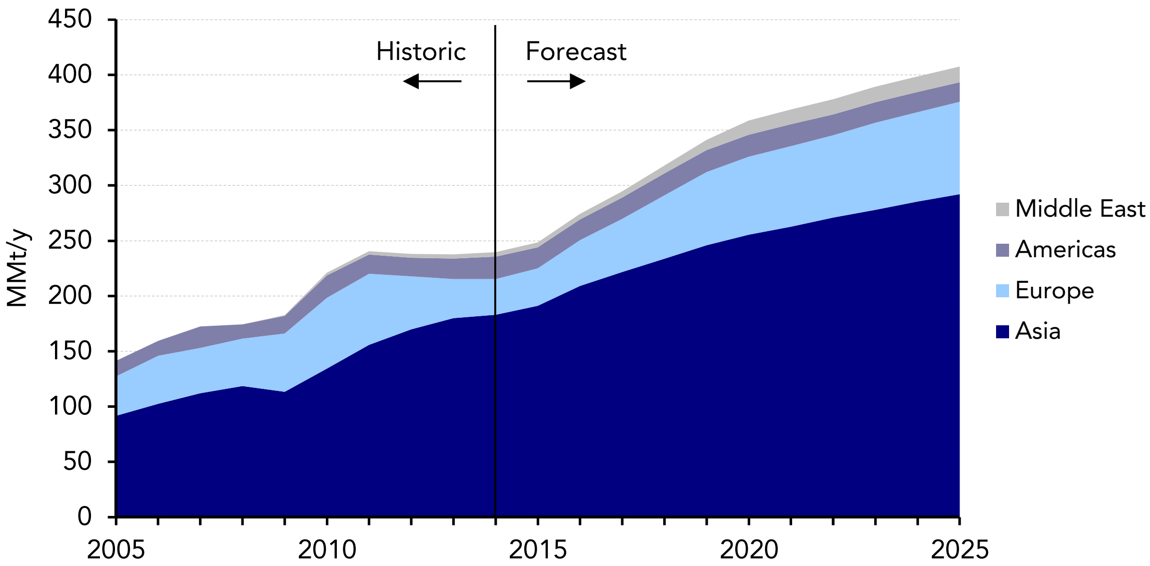
Australia is leading lead the next major LNG export expansion, while new capacity is also under construction in Papua New Guinea, Malaysia, Indonesia and Russia. Australia is projected to produce 75 MMt/y of LNG at 10 projects by 2020. However, high construction costs are such that no additional project sanctions beyond those already committed are expected for the foreseeable future.

North America and East Africa are expected to be key future LNG suppliers. By 2025, Poten projects North American (US and Canada) and East African (Mozambique and Tanzania) LNG exports to reach 69 MMt/y and 12 MMt/y respectively.

The US was once considered a major import destination and many LNG export projects, including ALNG, were built predominantly to supply this huge gas market. However, the surge in unconventional natural gas production has converted the nation into a potentially large LNG exporter rivalling Qatar and Australia, with over 200 MMt/y of potential supply at various stages of planning. Operators offshore Mozambique and Tanzania are reported to have discovered at least around 120 Tcf of gas reserves and plan to develop multiple LNG export trains. However, establishing the commercial and regulatory structures to support LNG exports will take time.

Global LNG demand has grown as the number of importing countries, largely to meet power generation needs, increased from 12 in 2000 to 29 countries in 2014. A combination of growing environmental and regulatory pressures, new LNG production capacity and competitive pricing are projected to drive a strong expansion of LNG imports, which are projected to grow to around 410 MMt/y by 2025 from around 240 MMt in 2014. Growth in LNG demand is anticipated in every major region, except North America (excluding Mexico) where robust growth in domestic shale gas production has almost eliminated imports.

Figure 9-7 Historical & Projected LNG Demand: Global



Longer-term, LNG demand will remain a key constraint to supply growth. Even considering our forecast robust demand growth, it is clear that there will only be sufficient markets to support the development of a fraction of the new liquefaction capacity that could potentially developed in North America and East Africa, for example, over the coming decade. This competitive pressure is expected to continue to apply downward pressure on LNG pricing, impacting new suppliers and existing suppliers negotiating contract renewals, such as T&T. This is being illustrated by declining prices in the market for long-term contracts. Both North America and East Africa will play an important role in setting future long-term LNG pricing as they compete for markets.

9.2.2.2 Current Pricing

Since natural gas developed as a regional business, gas and LNG pricing regimes and formula structures have developed to meet local constraints and the specificities of the regional end-user markets for gas. Accordingly, unlike the oil market, and although the situation may evolve in the future, gas does not currently have an international benchmark price. However, similarities lie in the extremely important influence that competing fuels, and in particular crude oil and oil products, have on gas prices on all the regional markets. Natural gas does not have a captive market, and is always in competition with other fuels: electricity, gas-oil and LPGs in the residential/tertiary sectors, electricity, coal and heavy fuel oil in the industrial sector, and coal, fuel oil and nuclear power in the power sector. Thus its price cannot deviate too much from competing fuels, which always offer a satisfactory replacement.

Generally speaking, the key regional price mechanisms are as follows:

- Asia – indexation to crude oil.
- North America – supply and demand fundamentals.
- Europe – indexation to crude/oil products or, increasingly, based on supply and demand fundamentals.

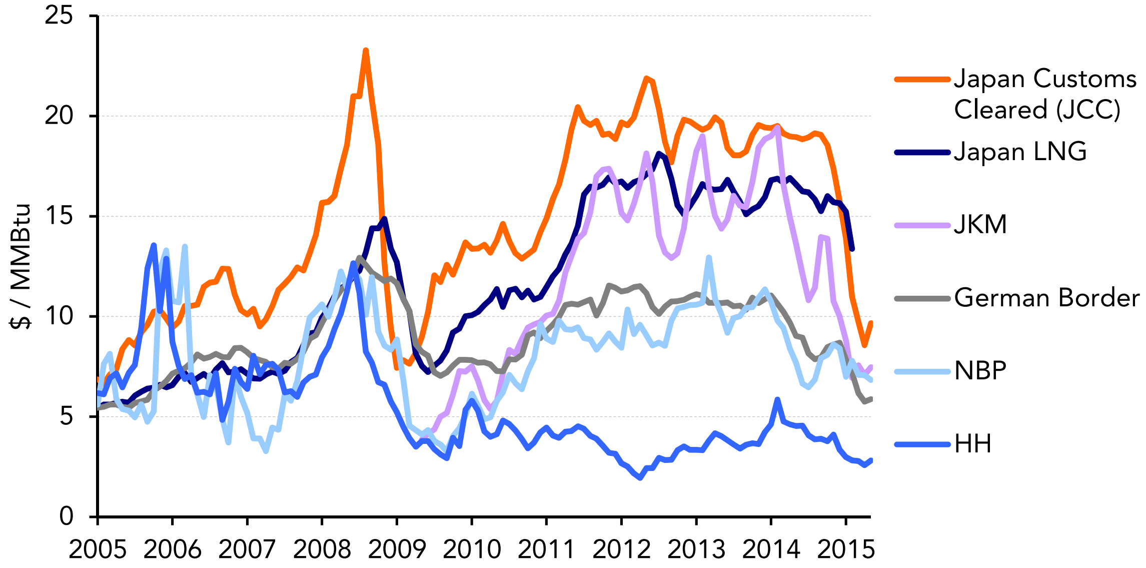
Until the very recent steep oil price decline, global gas prices have been increasingly divergent, as shown in the figure below. A decade ago regional gas prices, although set on different bases, were similar in value at around \$4-6/MMBtu. Other than in the US, gas prices have risen substantially since then, although NBP and JKM prices have declined markedly since the beginning of 2014.

A key factor in the changes in gas prices was the increase in oil prices from ~\$30/bbl in 2004 to ~\$110/bbl in 2013:

- Oil and gas prices in the US have decoupled as a result of shale gas developments.
- Asian prices have been sustained well above European (and North American) levels.

Recent lower oil prices will feed through to oil-indexed LNG prices after a time lag (3 months is typical in LNG SPAs).

Figure 9-8 Global Oil & Gas / LNG Pricing



Recent long-term Asian deals include lower oil indexation (14% of crude oil or less, versus the 15% level that has dominated the history of the industry), HH indexation or hybrid constructs. Growing supply competition, particularly from planned North American exports, is prompting some sellers to offer long-term hybrid pricing with an element of hub indexation alongside the traditional oil link.

The advent of the US liquefaction projects and the subsequent sale of long-term LNG has introduced the use of HH as a pricing reference for long-term LNG, with prices typically being set at 115% HH plus a constant (for example $3/MMBtu at Sabine Pass (with the exception of the first deals with BG and Gas Natural which were <$2.50/MMBtu) and $3.50/MMBtu at Corpus Christi), which is representative of the liquefaction costs incurred by the supplier. These price metrics will likely serve as an important marker for any future LNG supply deals from ALNG.

9.2.2.3 Price Projections

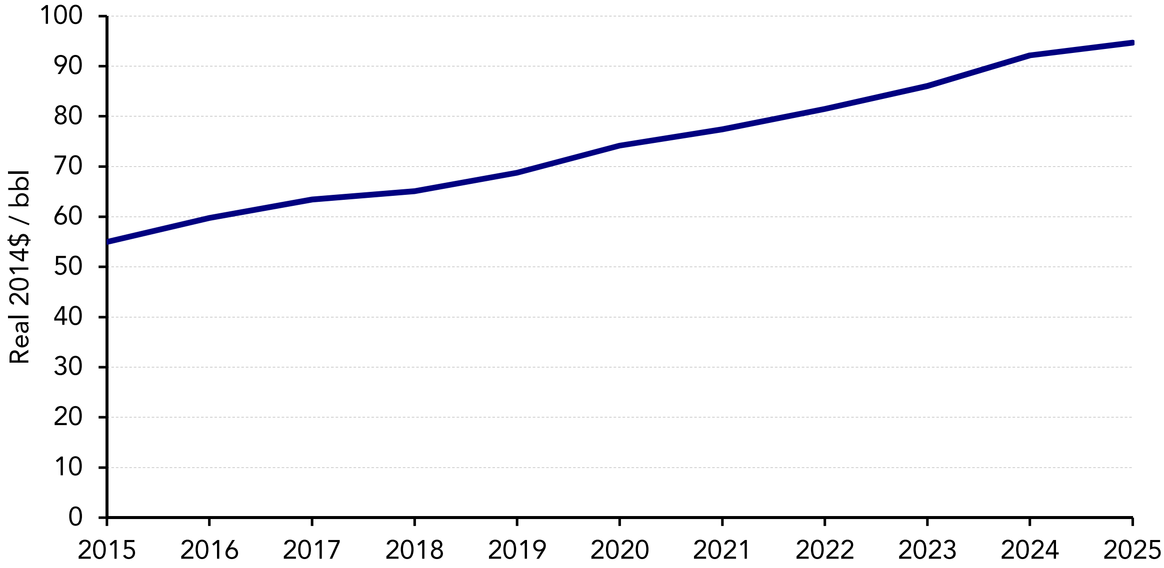
Oil Pricing

Oil prices are important for T&T, not only in the direct revenue streams from oil, LPG and condensates which are heavily dependent on global oil price levels, but through their effect on the revenues from gas-based industries (LNG and petrochemicals). For LNG exports, oil-linked pricing is expected to remain the dominant mechanism for pricing in long-term contracts for the Asia Pacific region despite an increasing volume of LNG with HH indexation (directly from North American LNG exports, but also from these projects' influence on price contracting from other suppliers that are considering hybrid pricing formulae). Oil prices also influence the global energy cost base and are an important influence on price levels for methanol and ammonia.

After several years of relatively stable high prices, oil prices suffered a near 60% decline between June 2014 and January 2015. The decline was driven by increased global supply availability, particularly from unconventional US supplies at a time when demand growth had stalled. The most recent collapse in oil prices is not unprecedented, and follows similarly sharp corrections since the oil shocks of the 1970s including the previous oil price collapse in 2008, as shown in Figure 9-8.

Our base oil price scenario envisages a modest and steady recovery in oil prices reaching around $75/bbl (2014 $) in 2020 and around $95/bbl (2014 $) by 2025. This scenario envisages US shale oil pulling down the marginal cost of production and having a long-term downward impact on pricing from the historical highs of 2011-2014.

Figure 9-9 Forecast Brent Crude Oil Prices



LNG Prices

Poten's LNG price projections are based on the oil price projections described above and our projections of regional gas pricing based on regional natural gas supply and demand and global LNG supply and demand trends.

Asian LNG prices are expected to continue to be heavily influenced by oil indexation, partly driven by the high cost of Asia Pacific supply projects, e.g. Australian grassroots projects which required high oil indexation levels and price floor support to support their investment decisions.

The large ramp up of North American LNG exports with pricing based on market prices (HH indexation) is bringing a new dynamic to global LNG pricing. It is also leading to the emergence of "hybrid" pricing (with a mixture of HH-based and oil–linked pricing) which may be implemented for new supply projects such as those in Western Canada and East Africa.

Another expected outcome from the surge in US liquefaction projects is that HH indexation will set a price floor for global LNG prices. At times of global market oversupply, the global price floor will be based on the marginal cost economics of US supply.

The European market is expected to act as a global balancing market, providing a market of last resort for any LNG which is not able to be placed into other markets. Although oil indexation may remain in legacy contracts, LNG delivered to Europe will be at market prices, based mainly on UK NBP or Netherlands TTF price indices. European prices will be set by the interaction of supply and demand in the European market, with floor prices expected to be set by the marginal cost of HH-sourced LNG into northwest Europe.

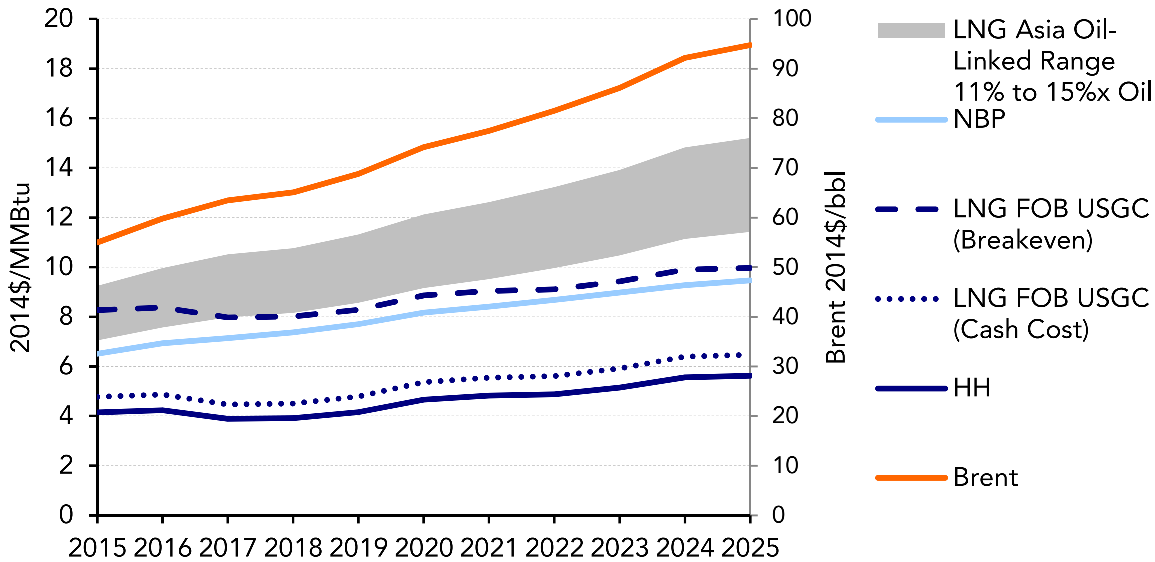
We expect downward pressure on the oil indexation slope of Asian long-term contracts due to the combination of (1) supply competition, (2) shift in marginal supplies from Australia to others (e.g., East Africa), and (3) intrusion of HH-linked contracts, increasing competition and forcing slopes down. For example, traditional JKT buyers (Japan, Korea and Taiwan) have procured more than 10 MMt/y of US

LNG (off-take and tolling capacities) partially to use as a bargaining power when negotiating with suppliers pressing for high oil-linked price formulae.

Australia has been the price setter for long term LNG, with slopes between 0.14 and 0.15 and we expect this to remain the upper bound on new oil-linked contract indexation. However, indexation terms could drop substantially as a result of the significant competition between suppliers to capture markets. As such we have assumed a lower slope range for new long-term oil-indexed contracts of 0.11, as shown in the figure overleaf.

US HH prices will drive the cost of US LNG exports, with prices into Europe derived from the North West European gas market prices (which follow UK NBP). LNG FOB USGC (Breakeven) prices are the minimum price that a USGC liquefaction capacity holder needs to realise on a long-term basis to breakeven and are based on HH gas prices plus fuel consumption of 15% plus a liquefaction cost of $3.50/MMBtu. These metrics are the actual cost structure of the latest US project to reach a positive FID: Corpus Christi LNG. However, we have also included LNG FOB USGC (Cash Cost) prices, which represent the cash costs of production once a liquefaction project has been committed to, i.e. the breakeven price minus the liquefaction cost, which is payable even if the liquefaction capacity holder does not want to offtake LNG. These are the prices below which the plant will no longer be operated, and represent a potential future regional price floor in a heavily oversupplied market situation.

Figure 9-10 Forecast Natural Gas and LNG Prices



9.2.3 Ammonia

9.2.3.1 Global Market

Overview

Ammonia is a major globally-traded chemical intermediate. Its main use is in the manufacture of nitrogen fertilisers, which account for over 80% of ammonia use. Anhydrous ammonia can be applied directly to soil in its pure form, although it is mainly used in the production of other solid or liquid fertilisers such as urea, ammonium nitrate (AN), ammonium phosphates - diammonium phosphate (DAP) and monoammonium phosphate (MAP), urea ammonium nitrate solution (UAN) and ammonium sulphate.

Fertiliser demand is driven by population growth and economic growth. Population demand increases food consumption of fruit and vegetables in developing countries, while economic growth also increases protein (meat) uptake, which results in higher grain consumption as animal feed. These combined effects boost fertiliser use in agricultural production, with increased demand for food being met by higher fertiliser application rates per hectare to boost production. Biofuels such as ethanol derived from corn and vegetable oils for biodiesel are also gaining importance and contribute to increasing demand for fertilisers.

Ammonia and its derivatives are also used in the manufacture of a wide variety of chemical products and industrial applications including plastics, fibres, explosives, nitric acid and intermediates for dyes and pharmaceuticals.

Ammonia is produced from natural gas via a syngas process. The main feedstock globally is natural gas, but it is also produced from liquid or solid fuel, for example in China where there is very large and growing ammonia production based on coal, while in India, naphtha is widely used.

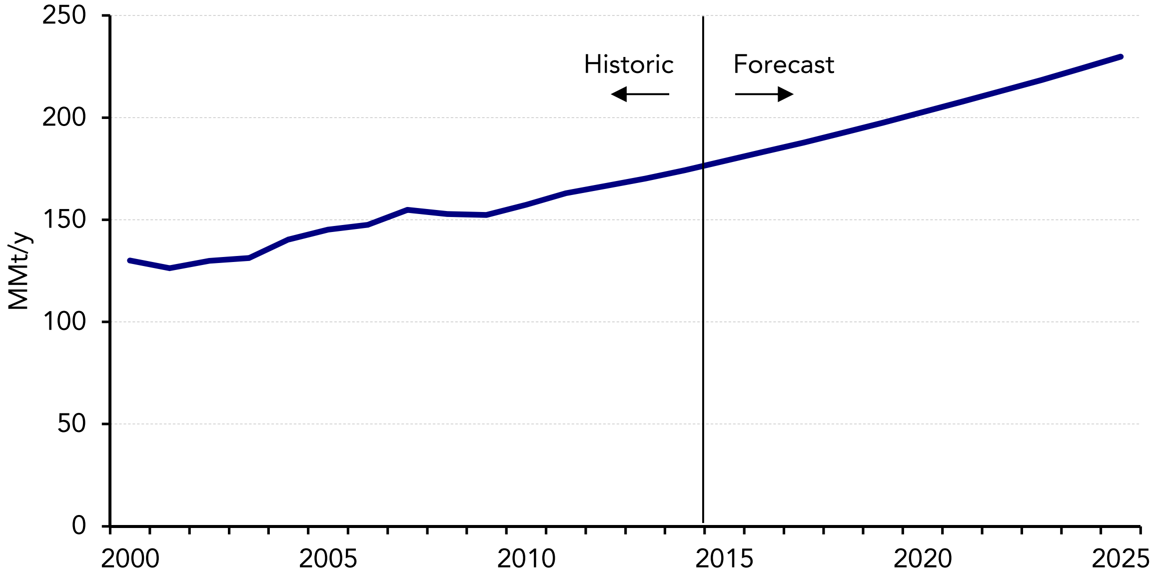
Supply & Demand

The global ammonia market is estimated at around 170 MMt in 2013. Global nitrogen-fertiliser demand is expected to continue to grow at around 2.3% p.a. or around 3 MMt/y of nitrogen (6 MMt/y of urea product). This equates to around 4-5 new world scale urea plants each year. Industrial use is projected to grow at a higher rate (3.7% p.a.), largely due to increasing demand for urea in emissions control applications.

Demand growth is expected to be strongest in developing regions, particularly Asia, and Latin America. Growth is expected to be more muted in North America. Global ammonia demand is projected to reach around 230 MMt/y by 2025, as shown in the figure overleaf.

Global ammonia production is dominated by China, which produces around one-third of global output (approx. 55 Mt/y). China is followed by Russia (14 MMt/y) and India (13 MMt/y) and then the US, with production of around 10 MMt/y in 2013. Global ammonia capacity is projected to grow around 4% to 224 Mt in 2015. New capacity is expected to come onstream in Brazil, China, Egypt, India, Indonesia, Russia and Vietnam.

Figure 9-11 Historical & Projected Global Ammonia Demand



New supply developments in the US will be key for T&T as the US is expected to become increasingly important in petrochemicals and bulk agro chemicals as a result of low gas prices (natural gas feedstock costs account for over 50% of the manufacturing costs for nitrogen fertilisers). This has already lead to the decline in imports seen in 2014, and we expect to see a continuing decline in US ammonia, urea and UAN imports as new capacity is built. There is around 6 MMt/y of new ammonia capacity expected on stream in in North America by 2018, mainly in the US. A whole host of additional projects are at the planning stage in the US, totalling more than 10 MMt/y of ammonia capacity. These proposed projects are at varying stages of development, and while we do not expect most of the plans to come to fruition, several undoubtedly will go ahead.

Although current projections (based on new supply projects which are reasonably firm) do not show the US as a net exporter of nitrogen, if these future plans came to fruition, the US could become a net exporter, and it would have to export to the emerging economies of Asia Pacific and South America. This would put US producers/exporters into competition with T&T for these markets. T&T, which mainly produces ammonia for the US market, will potentially be seriously affected as it will have to find new markets. In Asian markets T&T will see competition from the existing Middle East exporters to the region plus new US exporters. However, T&T's location would give it a logistical advantage over USGC ammonia and nitrogen exports to the growing South American market.

Trade

T&T is the world's largest exporter of ammonia (4.3 MMt in 2013), followed by Russia (3.4 MMt in 2013) and Saudi Arabia (1.6 MMt in 2013). Canada exports ammonia to the US (1.2 MMt in 2013) and Australia and Indonesia exported around 0.7-0.8 MMt to the Asian markets in 2013. Global ammonia trade has remained fairly constant over the last decade as most ammonia is consumed at its production site, with global trade standing at around 18 MMt/y for 2013 and 2014.

By far the largest ammonia trade flow is from T&T to the US where it is used in direct application of ammonia and to produce fertiliser and chemical products. India and Korea are also significant importers of ammonia, with imports mainly sourced from the Middle East and South East Asia. In the Atlantic basin, Morocco imports sizeable volumes of ammonia, for production of phosphate fertilisers.

Brazil is one of the fastest growing fertilizer markets. It imported 4.4 MMt of urea in 2014. It also imported 0.4 MMt of ammonia. In future, Brazil's demand for nitrogen and imports of ammonia are expected to increase as regions with phosphate reserves, including Brazil, typically lack nitrogen capacity and will need to import ammonia for new phosphate production.

Urea is much more easily transported relative to ammonia. According to IFA, global urea trade amounted to around 45 MMt/y out of global demand for urea 169 MMt in 2013. China is the largest urea market, both in terms of demand and production. Chinese demand for urea is estimated at 54 MMt in 2013, with production at 62 MMt, dwarfing the second largest producer India which produced 23 MMt of urea.

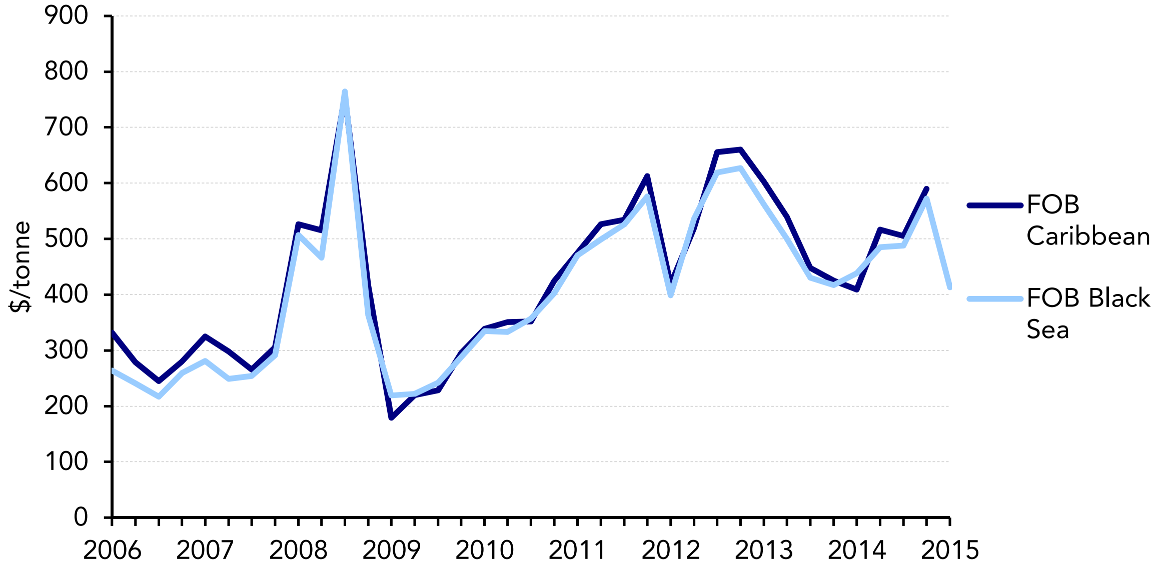
During 2014, there were significant disruptions in nitrogen capacity in Ukraine and Egypt. This led to a large increase in Chinese urea exports (which reached a record 14 MMt, or 30% of global trade of 47 MMt) to fill the market.

T&T's exports of urea currently are much smaller than its ammonia and methanol exports. However, downstream integration into urea instead of ammonia exports could provide a possible market outlet for ammonia production.

9.2.3.2 Pricing

Ammonia prices reflect the global supply and demand for ammonia and nitrogen fertilisers, with a floor price determined by the economics of the marginal global producer. Ammonia prices are cyclical, reacting to increases in demand and additions to capacity, with an underlying floor price based on the economics of the marginal producer. International trade in ammonia is much less than for its derivatives and the cost of freight for ammonia is a significant factor in regional trade patterns with most material in the Atlantic basin staying within its basin of production and the Middle East exporting eastward. Historical ammonia prices are shown in the figure below.

Figure 9-12 Realised Ammonia Prices
(source: NGC, Yara)

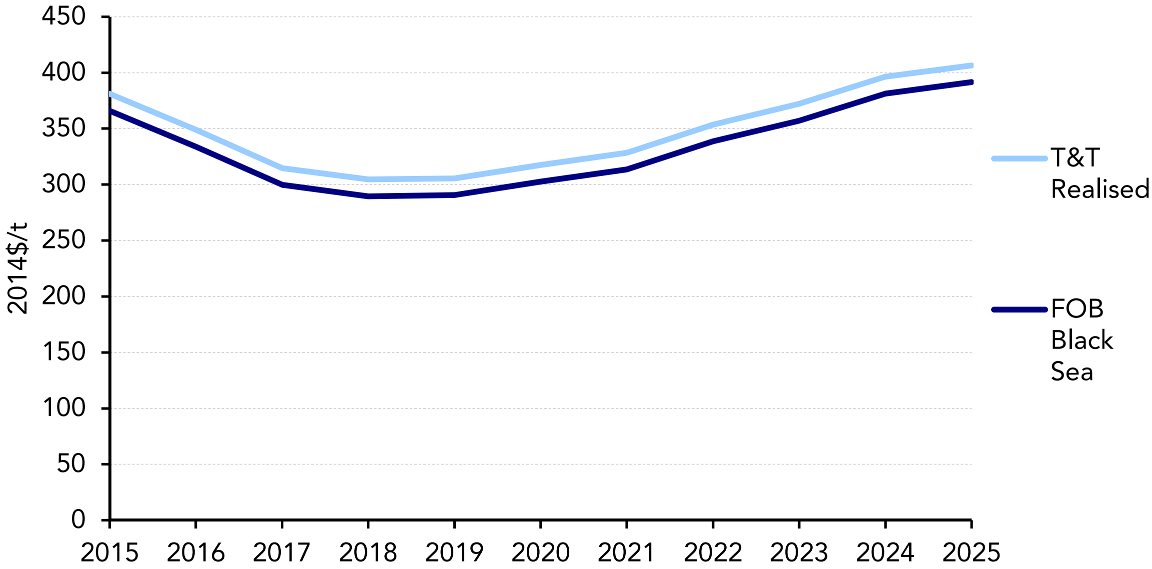


The marginal highest cost production is currently ammonia/urea produced from Chinese coal. We expect that global pricing will continue to be supported by the need for production from higher cost regions including Ukraine and Western Europe, with Chinese coal-to-ammonia economics providing a floor price. New production in low cost gas regions including new US production will be price takers.

The FOB Caribbean ammonia price is used by NGC to calculate the feedstock pricing for natural gas. The average ammonia price is computed based on international industry publications: Fertecon, FMB and Green Markets. Historically FOB Caribbean prices have been broadly in line with FOB Black Sea marker prices and we expect this to continue.

Poten's projections for ammonia prices fob Black Sea are shown in Figure 9-13. They show prices declining to around $300/tonne by 2017-2020 before a steady increase to around $400/tonne by 2025 (2014$).

Figure 9-13 Forecast Ammonia Prices



9.2.4 Methanol

9.2.4.1 Global Market

Overview

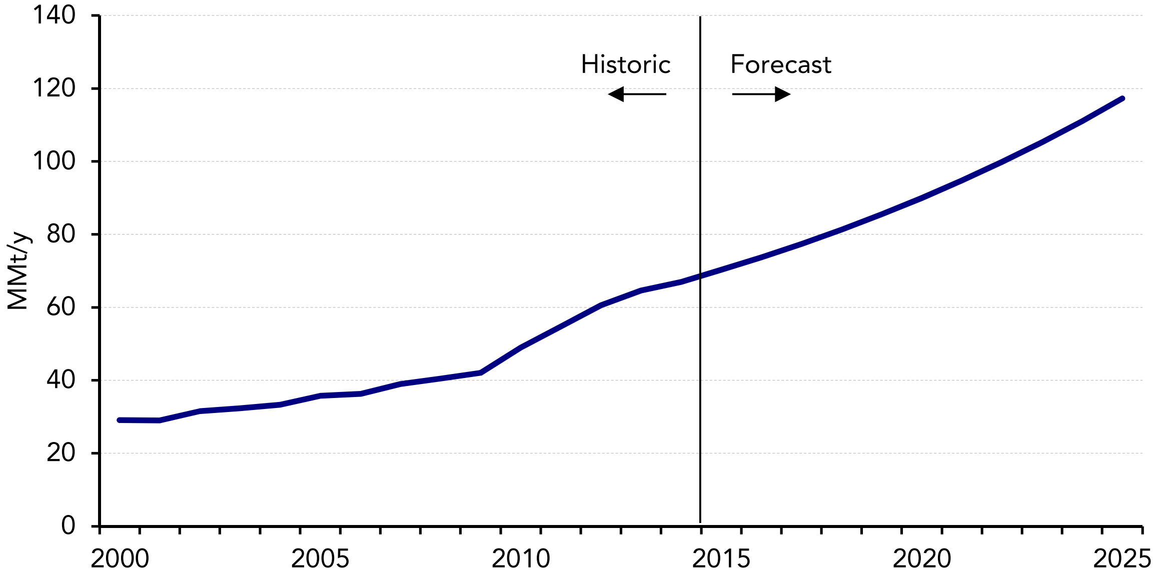
Methanol is an important global commodity chemical. It is the simplest alcohol with chemical formula CH_3OH. Outside of China, which has a very large and growing production capacity based on coal, methanol production is mainly from natural gas feedstock, which accounts for around 70% of production due to its cost advantages. Historically, gas-based capacity has been focused on low-cost regions such as the Middle East, but the advent of the shale gas revolution in North America will see a large increase in methanol production capacity in the US, including relocation of two plants from Chile to Louisiana.

The major uses for methanol are as a chemical intermediary in the production of wide variety of downstream derivative products, and the use of methanol or methanol derivatives as a fuel.

Supply & Demand

Global demand for methanol (excluding methanol demand in vertically-integrated Chinese CTO plants) is estimated at around 67 MMt/y in 2014. Including methanol consumed in CTO, the total methanol market is estimated at 72 MMt/y. Chinese demand is driving the global methanol market. Demand in China is growing at around 12% p.a. while the rest of the world has seen growth rates just over 3% p.a. Methanol to olefins and gasoline blending are leading the growth in the Chinese market. Global methanol demand is expected to reach 117 MMt/y by 2025, as shown in the figure overleaf.

Figure 9-14 Historical & Projected Global Methanol Demand



China is the largest producer of methanol globally, accounting for nearly 50% of all installed capacity worldwide. Ownership of China's methanol production is highly fragmented, with many hundreds of small producers as well as very large coal-to-methanol and integrated coal-to-olefin producers. Chinese methanol production is centred on the remote and abundant coal resources in northern China (Inner Mongolia, Shanxi and Shaanxi provinces) and western China (Xinjiang and Ningxia provinces).

The rise of North American shale gas has already resulted in the restart of existing plants and the construction and start-up of new plants in North America. As well as several smaller expansion projects and debottleneckings, the past three years has seen the restart of three plants. Over 4 MMt/y of capacity is under construction in the US including two new plants and a relocation from Chile. In addition, more than 9 MMt/y of methanol capacity is in advanced planning or has been proposed in North America These plants see their markets as supply targeting the North American fuel-blending market and secondarily the Chinese export market. We expect to see a continued large build up of methanol capacity in North America, driven by abundant, cheap shale gas.

Trade

Iran, T&T and Saudi Arabia are the largest global net exporters of methanol, each exporting volumes around the 4 – 5 MMt/y range. These positions have been developed on the basis of low cost feedstock gas (less than US$1/MMBtu in the cases of Iran and Saudi Arabia). However, low prices in the Middle East have led to booming domestic demand for gas and have resulted in gas shortages, such that we would expect gas prices to be substantially higher for any future projects.

The USA and China are the key global methanol importers. Net imports into both the USA and China were of the order of 5 MMt in 2013/14. Other major import markets are Japan, South Korea and the EU.

9.2.4.2 Pricing

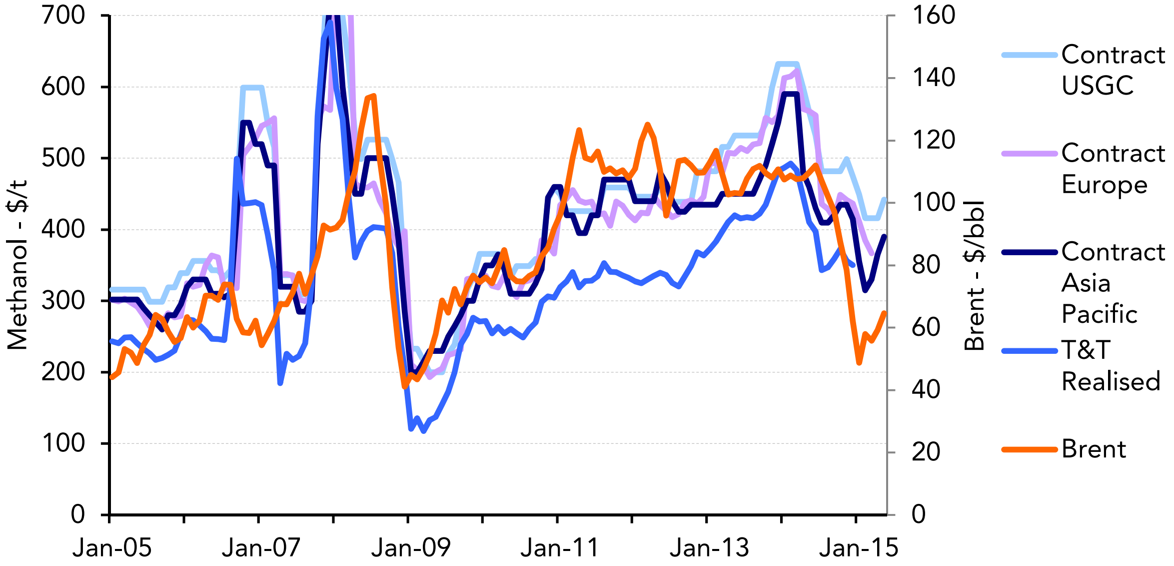
As with other commodity chemicals, methanol prices respond to market forces. However, two key underlying factors are seen as the major drivers for methanol pricing:

- Production costs, which are in turn mainly driven by feedstock prices. The cash cost of production (from low cost natural gas or coal in China) sets a floor.
- Margin over costs which is driven by supply and demand fundamentals. Prices can be well above costs if demand is high.

Methanol prices have historically been very volatile, as shown in the figure below, and are sensitive to global supply and demand dynamics. However, the economics for fastest growing methanol uses and derivatives (gasoline blending, MTO and DME) are based on substitution of or competition with oil products, particularly in the Chinese market (methanol gasoline blending and MTO).

Figure 9-15 Methanol and Crude Oil Prices

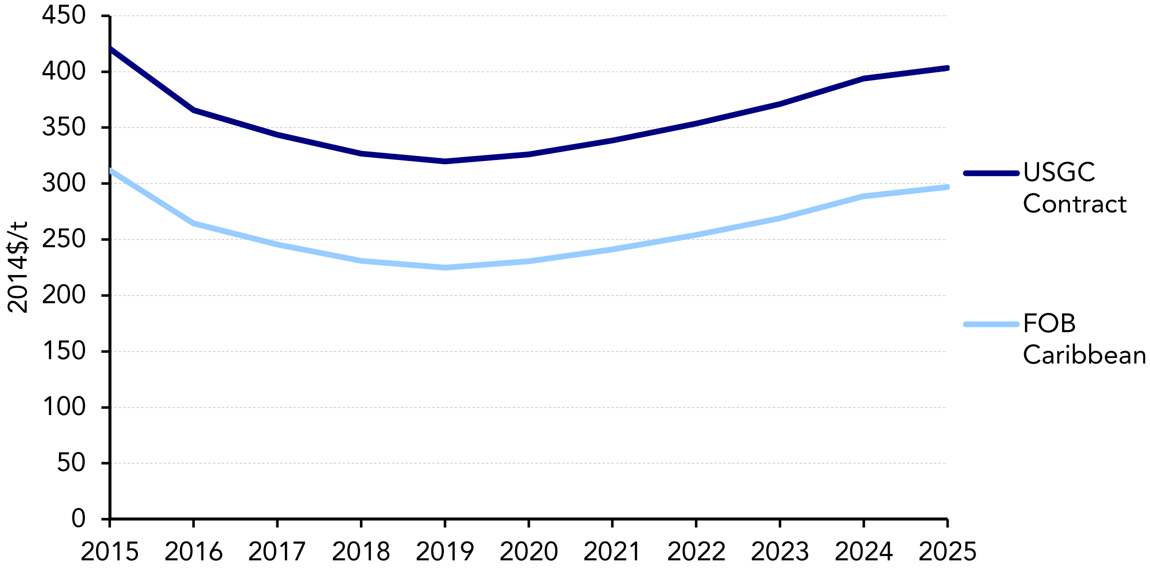
(source: NGC, Bloomberg, Methanex)



This has had the effect that methanol prices have increasingly tended to correlate with crude oil prices. We expect that methanol prices will continue to be correlated with oil prices, with supply and demand factors playing a less significant factor.

The T&T realised methanol price is used by NGC to calculate the feedstock pricing for natural gas. It is calculated on a proxy-netback basis from market methanol prices (mainly the USGC market, but increasingly in future, we expect from European and Asian prices). The differential between the posted contract prices and fob T&T price consists of shipping and logistics costs from T&T to the market and the marketing discount (large methanol buyers obtain a discount of 10-15% from posted prices).

Figure 9-16 FOB USGC Methanol Contract Price Forecast



Methanol prices are expected to decrease from current levels to around $320/tonne by 2019, as lower oil prices feed through to lower methanol prices, before recovering over time to around $400/tonne by 2025 (2014$). Realised netback prices to T&T producers will continue to reflect a market discount of ~15% and freight cost differential from USGC contract prices.

9.3 GAS PRICING

The pricing of gas through the value chain is the primary mechanism (along with taxation) for the allocation of economic rent. Gas pricing should be such that risk and reward are balanced and the distribution of economic rent is equitable so that all players all along the chain are incentivised to continue to invest and optimise their respective contribution to the chain, and that the value to the people of T&T, who are the owners of the resource, is maximised.

9.3.1 Gas Pricing in T&T

Gas pricing in T&T, and indeed the commercial structures generally, reflect the evolution that the market has undergone in the last several decades. In the early years the commercial structures developed reflected the conditions at the time. There was abundant gas but the market for gas was undeveloped and there were significant uncertainties for downstream marketers in terms of offtake and affordability of products. Many downstream investments (e.g. methanol plants) were adding significant incremental capacity to the global market and there was some uncertainty over the evolution of product pricing. Gas pricing at this time was generally on a fixed price basis. The downstream markets evolved and matured over the past 10-15 years, and structural changes in markets have led to a change in the relative risks associated with different parts of the gas value chain. Gas pricing in T&T has evolved with the markets; for example in the 1990s product related netback pricing was introduced for petrochemical gas supply.

9.3.2 Pricing Arrangements / Framework

In T&T the price of gas is set according to end-user. As a result, prices vary according to buyer: LNG, petrochemical production, power generation, heavy industry, or general commercial as shown in the following table:

Table 9-8 Gas Pricing Structures in T&T

End Use	Pricing Mechanism
LNG	Netback pricing
Petrochemical (ammonia and methanol)	Product indexed pricing
Power Generation	Set by GORTT
Heavy industry	Cost plus
Light industry	Cost plus
Commercial	Set by GORTT

NGC has attempted to match upstream and downstream pricing through its gas contracts. NGC's gas sales contracts with the petrochemical industries have netback pricing based on indexation to the end product, e.g. ammonia or methanol. This pricing is reflected in some upstream gas supply contracts to NGC (e.g. bpTT supply contract to Atlas methanol) but NGC is potentially exposed to pricing mismatches as volumes and/or terms may not be perfectly matched across the portfolio. From the information provided by NGC it is evident that where there is dedicated supply to downstream industries NGC is adequately protected by the pricing mechanisms.

The specifics of the gas pricing arrangements into the main downstream consumption sectors are discussed in Section 10.

The contractual arrangements in place in T&T today reflect the market conditions at the time that they were negotiated, and as the primary initial term for most gas supply contracts was 20 years, the older contracts have an economic reward profile which is not necessarily aligned with the present market conditions. Over the next decade a number of key gas supply and LNG offtake arrangements will expire. Accordingly GORTT has the opportunity to reassess the commercial balance of these contracts to ensure that the distribution of rent is equitable and the returns to the resource holders and GORTT (and the people of T&T) is optimised in all parts of the chain.

The risk taken by the various participants across the various elements of the value chain is not even, nor is it static. For example in the early years there is significant risk for upstream investors when there is no market in place; as the sector evolves this market risk diminishes. The general risk exposure by value chain element can be characterised as follows:

- Upstream producers will typically invest significant capital on an annual basis, both developing new fields while reinvesting in old ones in order to maintain a steady gas supply. There is significant investment in exploration and production which is many years ahead of any revenues being realised.
- Midstream transportation is a utility business which is relatively low risk. Incremental capacity is only brought on in line with demand.
- Wholesaling is a marketing function which requires no capital investment. Typically margins in trading of gas are very low.
- An LNG plant initially has very high capital investment but once operational the plant becomes essentially a utility facility. An LNG tolling facility is entirely a utility operation. The marketing of LNG has some price risk in a traditional merchant arrangement although this is limited in a netback arrangement.
- Petrochemicals production has a similar risk profile to LNG in that it involves a high capital investment followed by much lower operation expenditure. There is some marketing risk due to the commodity price volatility, although netback pricing manages the price exposure.
- Domestic downstream consumers are mostly utility type operations (Power, PPGPL, Refinery)

This risk exposure across the T&T value chain is shown in the table overleaf.

Table 9-9 Risk Matrix for T&T Gas Value Chain

Risk	Upstream Shallow Water	Upstream Deepwater	Midstream		Downstream		
	Exploration and Production		Transmission	Wholesaleing	LNG	Petrochem	Domestic
Exploration Risk	Medium Risk Most shallow water resources are identified	High Risk Virgin territory for exploration	n/a	n/a	n/a	n/a	n/a
Reservoir Risk	Medium Risk Significant work done in establishing resource level	High Risk High uncertainty in deepwater blocks	n/a	n/a	n/a	n/a	n/a
Development Risk	Medium Risk High development expenditure	High risk	Low Risk Incremental capacity will be demand driven	n/a	n/a	n/a	n/a
Operational Risk	Medium Risk Will need to integrate with existing infrastructure	Medium Risk Will need to integrate with existing infrastructure	Low Risk Utility function	Low Risk Intermediation	Low Risk Plant proven in operation	Low Risk Plant proven in operation	Low Risk Plant proven in operation
Market Volume Risk	Low Risk Well developed market in T&T for gas	Low Risk Well developed market in T&T for gas	Low Risk Utility function	Medium Risk Increased risk of shortfall in portfolio	Low risk Large and growing market for LNG	Low/Medium Risk Producers pushed to new markets but have global marketing companies	Low Risk
Market Price Risk	Medium Risk Export markets would provide adequate netbacks Domestic markets problematic	High Risk Gas is likely to need high price if not with significant NGL/oil stream	Low Risk Transmission costs are small	Low Risk NGC matches prices	Low Risk T&T low cost supplier so should retain healthy margin	Low/Medium Risk Producers will have higher tx costs and more competition	Low Risk Government determined pricing
Policy/Fiscal Risk	High Risk Government may change fiscal terms	High Risk Government may change fiscal terms	Low Risk Government owned company	Low Risk Government owned company	Low Risk	Low Risk	Low Risk
Financial Risk	High Risk Availability of corporate capital	High Risk Availability of corporate capital	Low Risk	Low Risk Not capital intensive	Low Risk Investment amortised, no 4x exposure on exports	Low Risk Investment amortised, no 4x exposure on exports	Low Risk

In order to ensure maximum participation and equity across the gas value chains, it is important to ensure that the commercial structures match the economic reward derived from participation in the chain with the associated risk undertaken.

The use of netback pricing in LNG and petrochemical gas supply already allows T&T to share in the upside movement of commodity prices. The key issue is not the pricing mechanism so much as whether the products are being sold in the highest value markets and whether the price mechanisms capture the appropriate resource rent.

Domestic gas pricing is an important consideration for the gas industry, with prices set low for several consumers/groups/industries. In most countries where there are competitive markets the supply of gas to the power sector usually provides the highest value option for the producer, as gas will be competing with alternate forms of power generation. In T&T GORTT has elected to provide power at a highly subsidised price as a means of distributing the wealth generated from the energy sector to the wider population. RIC sets the price at which T&TEC sells power to different classes of consumer. In order to sustain T&TEC financially NGC sells it gas at a current price of around $1.35/MMBtu, with annual inflation escalation.

This has caused major distortions in the gas value chain as the price is below the economic cost of production of many of the upstream suppliers. This situation is managed by NGC. NGC is able to offer gas to T&TEC at the regulated price because it can pool gas supply and charge a higher price to other industries, notably the petrochemical industry. There are several issues with the way in which power is priced in T&T:

- The low price of power does not encourage energy efficiency and it is evident that a large amount of the power generated is not used effectively. A power price in line with that charged elsewhere in the Caribbean would encourage more efficient energy use and bring greater revenues to T&TEC. In the short term it would reduce the amount of power required and the amount of feed gas.
- The low gas price also diminishes the incentive and the ability of T&TEC to invest in more efficient generation capacity (e.g. CCGT plants which have a thermal efficiency of ~50% compared to the efficiency of the open cycle plants of less than 30%.) If T&TEC moved entirely to CCGT generation as is the plan at the present time there would be a significant reduction in gas consumption. This is in addition to any saving through more effective pricing identified above.

It is widely documented that such subsidies are relatively ineffective in benefitting the intended target of the poor/less well off in society[1]. In fact the benefits accrue largely to the better off sections of society who have larger homes, more appliances etc. It would be more effective for GORTT to more directly target the poor by making direct payments through welfare support or, as a second best option, limiting the amount of electricity that qualifies for the low electricity price. Users consuming more than the qualifying amount would pay a higher price on the excess, which should be set at a level to cover the cost of the subsidy.

While all governments understand that removing subsidies will be unpopular, this price distortion is not in the best interests of the country as it is effectively a misallocation of an increasingly scarce resource. As the revenues from the oil and gas sector decline the need to amend power pricing to a rational level will be unavoidable, as the subsidy will become unaffordable. The longer this issue is not addressed the more painful it will be when that time comes.

[1] For example Water, Electricity & the Poor – Who Benefits from Utility Subsidies; Komive, Foster, Halpern, Wodon World Bank 2005

Section 10 Downstream: Commercial Arrangements & Value

10.1 INTRODUCTION

In an environment in T&T where overall gas supply availability is expected to decline over time, there will come a point at which gas supply is insufficient to support the operation of all gas-based industries. Decisions will need to be taken in future over which industries/ plants are prioritized for supply over others. These decisions should be principally related to maximizing the "value" of T&T remaining gas resource base for the benefit of the country and its people, which is in line with Gas Sector policy as described in Section 2 of this report.

The key determinant of "value" is the overall GORTT take from each of the gas value chains. The aim of this section is to provide an assessment of this take for the key gas-based industries, as well as an assessment of the degree to which value is not being captured by GORTT along the value chain. Details of the methodology and data used to undertake the analysis are provided in Appendix I.

10.2 LNG

10.2.1 ALNG Train 1

10.2.1.1 Project Structure

The first liquefaction train at ALNG (Train 1) is a separate entity (ALNG Co.) that purchases feed gas from bpTT[1] and sells LNG, i.e. a merchant structure, as shown in Figure 10-1. The project delivered its first LNG in April 1999.

The project was driven by a need to monetise the gas resources of Amoco and BG in T&T as well as the desire of Cabot to secure new LNG supplies for its New England market. The remaining project sponsor was NGC. BG ultimately did not prove up sufficient reserves in time to participate in the gas supply to Train 1, which was left to Amoco.

An integrated structure was considered whereby each project participant has the same proportion of ownership interest in the upstream and liquefaction segments of the project and in LNG sales. However, this would have required NGC and Cabot to be brought into the upstream and a system of cross shares between Amoco and BG fields would have had to be agreed. Due to the likely complexity of such negotiations and Cabot not wishing to invest upstream this structure was not pursued. A tolling structure was also considered but discarded. By default this left a merchant structure as the only workable solution.

Enagas also entered the project as a buyer and its parent company, Repsol, used this position to gain a stake in the liquefaction project as it looked to expand its upstream interests[2].

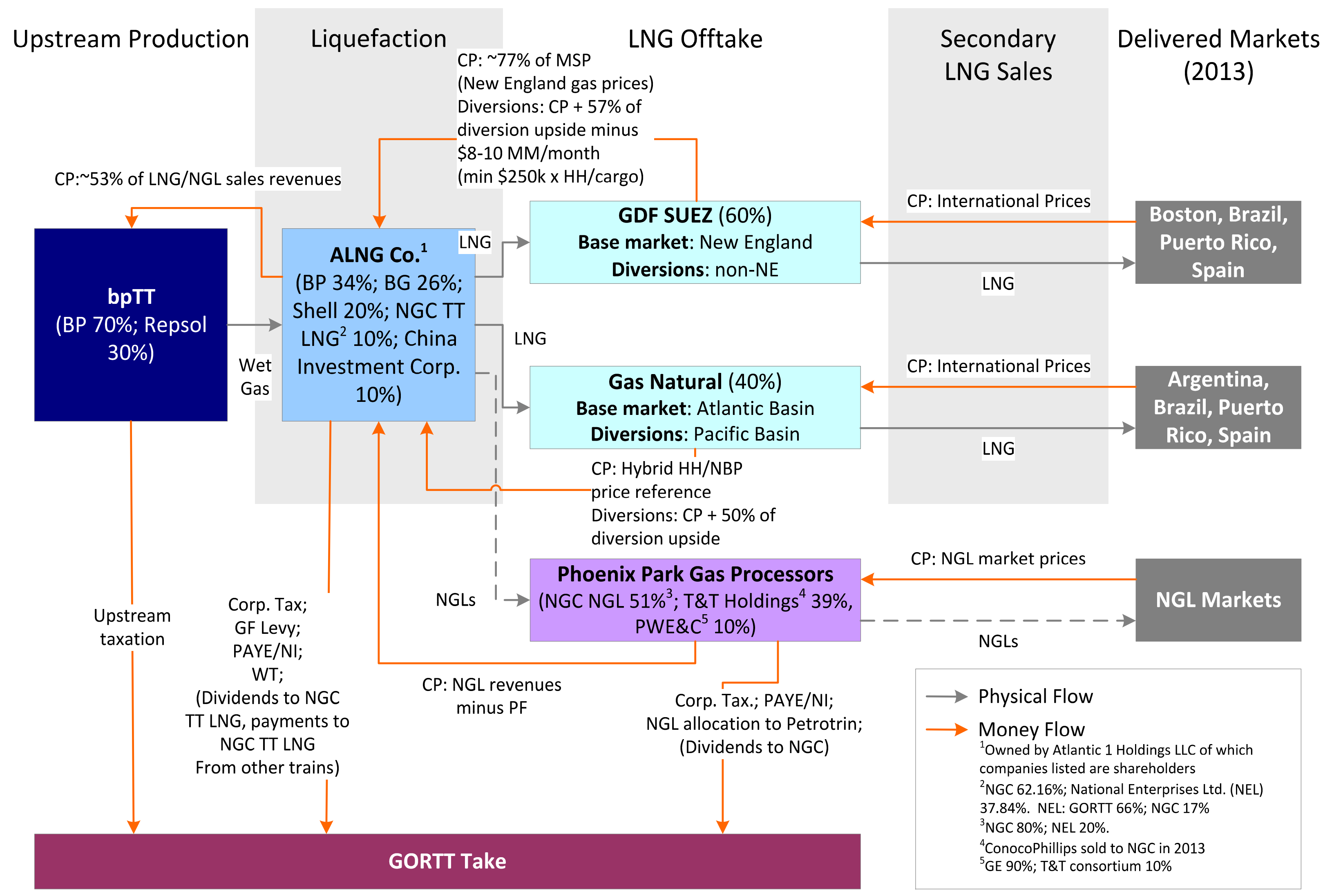
10.2.1.2 Marketing Arrangements & Netback Pricing

To share risk between the upstream and LNG plant it was determined that the price of the feed gas should be linked to the price of LNG. The average feed gas price is around 53% of the total plant revenues for LNG and NGLs, with the remainder retained by the plant.

[1] Amoco was the original participant in Atlantic LNG. Amoco merged with BP in late 1998 to form BP Amoco, and later BP.

[2] In January 2000, Repsol acquired a 10% interest in BP Trinidad with a right to secure up to 30% ownership in return for offering LNG marketing opportunities in Spain to BP. Repsol increased its ownership in BP Trinidad to 30% in 2003.

Figure 10-1 ALNG Train 1 Physical / Financial Flows



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The project sells 60% of its LNG under long-term contracts to GDF Suez (now called Engie) – originally Cabot – and the balance of 40% to Gas Natural (originally Enagas) on a Free-on-Board (FOB) basis, i.e. the buyers take responsibility for LNG shipping. These 20-year contracts are understood to expire in early 2019. The project also produces NGLs which are sold to Phoenix Park Gas Processors Limited (PPGPL).

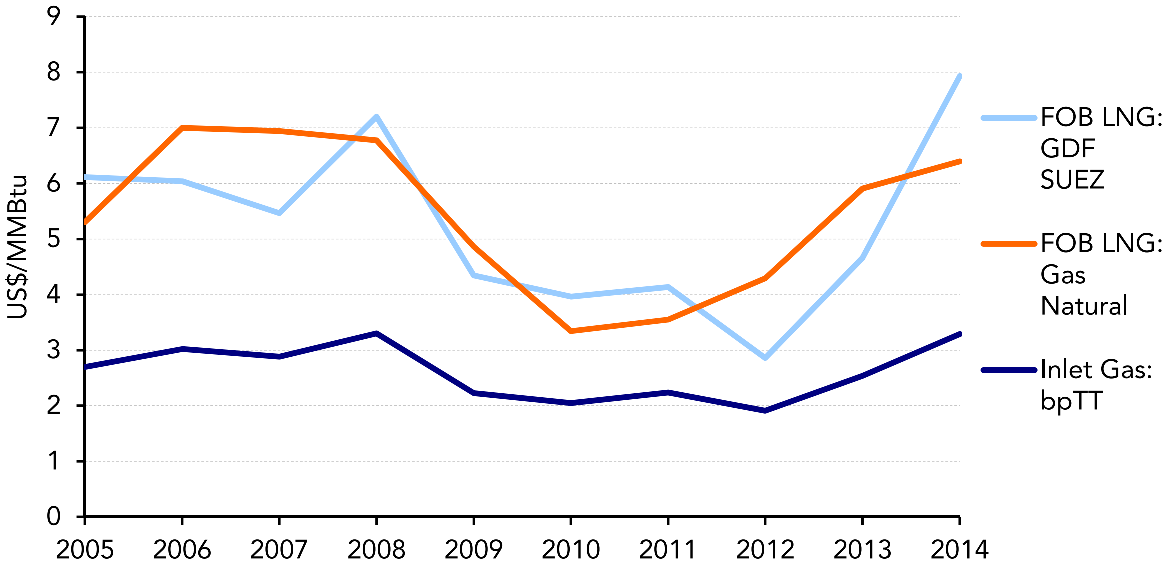
At the time of development Cabot had an LNG ship and Enagas also had LNG shipping experience, while Amoco did not wish to pursue a position in LNG shipping. As such FOB sales were agreed upon. In addition, in order to promote the development of the project, considerably greater destination flexibility was granted to the LNG buyers than was common at the time the project was being developed, including cooperation on liftings and swap arrangements between the two buyers. Sales to GDF Suez remain tied to the New England market and are priced on the basis of gas prices realised in this region, although there is a mechanism in place for the upside for any diversions to higher value markets to be shared between GDF Suez and the project. Diversions were historically limited due to GDF Suez's downstream gas supply commitments. However, a Memorandum of Understanding (MOU) was signed with GDF Suez in December 2013 to encourage it to seek higher value markets for its LNG from Train 1 and compensate it for doing so.

The Enagas contract was based on sales into Spain but with the option to sell cargoes to Cabot's Everett terminal in New England. The LNG prices under the Enagas contract were calculated using a base price and a multiplier indexed quarterly based on a mix of European gas oil and fuel oil prices, regardless of whether the LNG was taken into Spain or the USA. Following an arbitration decision in 2008 this was changed such that for the calendar quarters when the majority of cargoes were shipped to the Everett terminal, the price of LNG for all contracted volumes, even those destined for Spain, would be based on the Boston City Gate price. If the majority of cargoes were shipped to Spain, all LNG for that quarter would be priced according to the Spanish pricing formula. Following a Letter of Agreement (LOA) between Gas Natural and ALNG Co. pricing is now on a hybrid NBP/HH basis for sales to any Atlantic Basin destination, with diversion upside for sales outside the Atlantic Basin being shared.

10.2.1.3 Realised Prices & Value Loss

The inlet gas prices and realised FOB LNG prices for Train 1 are shown in the figure below.

Figure 10-2 ALNG Train 1: Plant Inlet Gas & Realised FOB LNG Prices



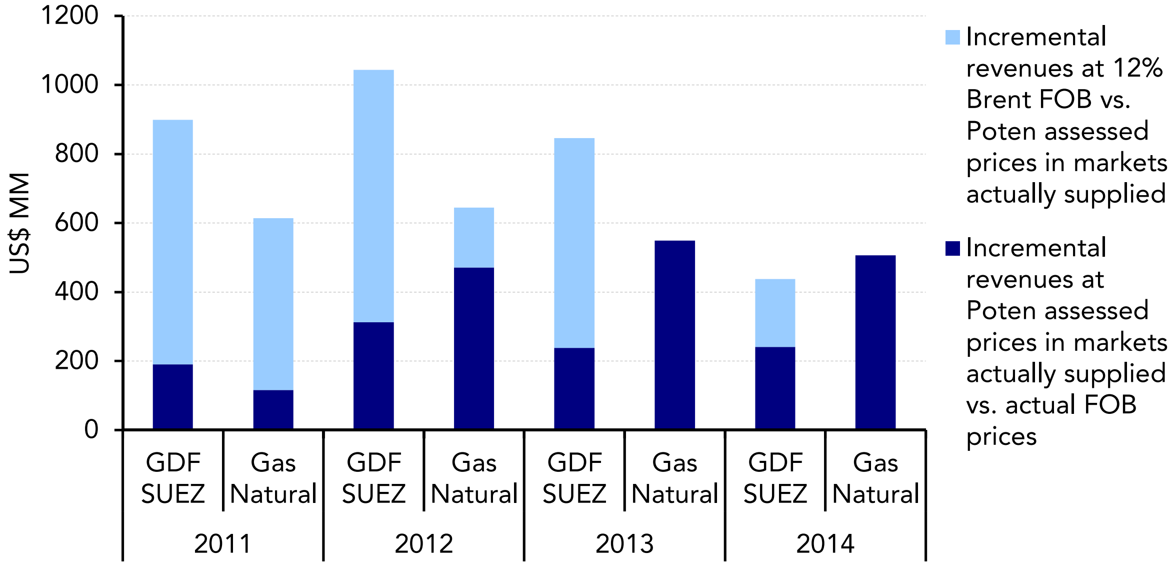
A clear trend on the LNG sales side is the decline of FOB prices post-2008, which were pulled down as a result of declining US gas prices. The impact of the MOU to encourage diversions can be seen in the jump in FOB LNG prices for GDF Suez from \$4.66/MMBtu in 2013 to \$7.94/MMBtu in 2014. Even during higher priced periods the netback price to the plant inlet for bpTT has been modest over the period reviewed, peaking at \$3.40/MMBtu in 2008.

As illustrated in Figure 10-3 below, Poten has undertaken an analysis for the 2011 to 2014 period to compare the realised FOB LNG revenues for Train 1 versus:

- Poten's assessment of FOB prices based on our intelligence of market pricing in the markets actually supplied by GDF Suez / Gas Natural, minus our assessment of shipping costs, i.e. assuming that these markets would have supplied in any case what has been the FOB value loss as a result of the Train 1 commercial arrangements.
- The revenues that would have been realised if the LNG had been sold at 12% of Brent FOB. This is an arbitrary figure but is probably a reasonable, conservative assessment for what LNG could have been sold at over the period in question, had the existing contractual arrangements not been in place.

This is an attempt to quantify the value loss suffered by Train 1 as a result of the existing LNG marketing / offtake arrangements.

Figure 10-3 ALNG Train 1: Value Loss

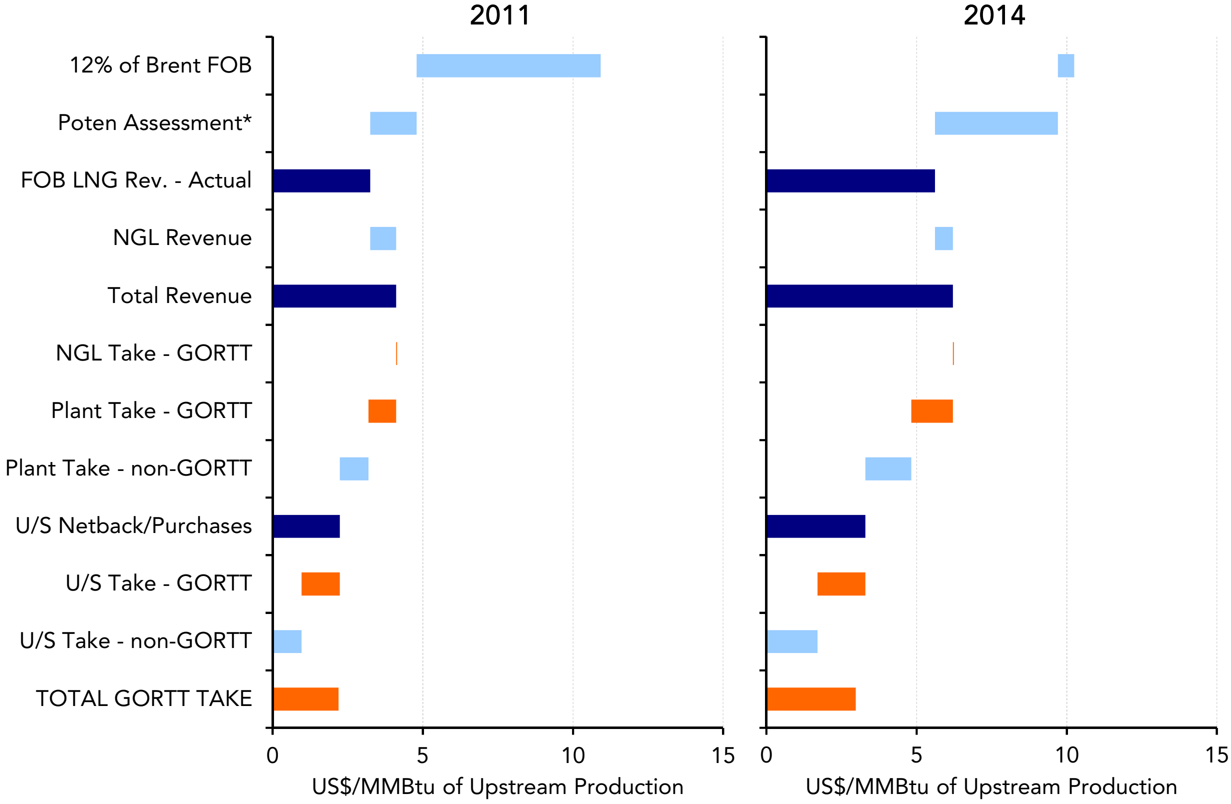


It is clear that substantial value loss to Trinidad has occurred over the period in question, with the difference between realised FOB revenues and those which would have been realised at 12% of Brent FOB reaching at least $1.4 billion each year from 2011 to 2013. The reduction is value loss in 2014 under the GDF Suez contract as more diversions were encouraged is also apparent. It is also worth noting that value loss under the Gas Natural contract has shifted from being focused on the lower-priced markets that Gas Natural was supplying to in 2011 (e.g. US, Spain) to a lack of netting back revenues to the plant from high value markets in 2014 (e.g. Argentina). With the benefit of hindsight and in light of the very high LNG prices in Latin America over recent years, allowing Gas Natural to divert to any Atlantic Basin market without sharing any of the diversion upside under the revised LOA has represented substantial value loss for Train 1.

10.2.1.4 Revenue Waterfall / GORTT Take

Poten has undertaken an assessment of both the overall revenue waterfall for Train 1and the GORTT take along the value chain for both 2011 and 2014, as shown in the figure below.

Figure 10-4 ALNG Train 1: Revenue Waterfall / GORTT Take



*Poten assessed prices in markets actually supplied

For each of the LNG projects, GORTT take from the plant consists of Corporation Tax, Green Fund Levy and Withholding Tax, as well as the share in the plant profits (plus payments made by the other trains) from the NGC/NEL stake. Due to incomplete data across the various industries we have not included PAYE taxes in our analysis. GORTT upstream take is based on assessment of the taxes that were paid by the upstream suppliers that could be attributed to gas production.

It is clear that the overall GORTT take from Train 1 has been relatively modest over recent years in comparison to the overall value that the project's value chain has generated. In particular there has been a significant capture of value offshore, i.e. beyond the T&T tax net, either in relatively low value markets being supplied with LNG from Train 1 or high value markets being supplied but with the revenue not flowing back to T&T. This is a common feature across each of the LNG trains.

The merchant Train 1 flows back a significantly lower proportion of FOB revenues to the upstream (~53%) than Trains 2, 3 & 4 (typically 70+%). This is also to the detriment of GORTT take as the Corporation Tax take downstream is lower than the corresponding take would have been had greater revenue been pushed back upstream, although this is mitigated somewhat by NGC's ownership stake.

Taking 2014 as an example, overall FOB revenue at 12% of Brent would have been \$10.25/MMBtu plus \$0.60/MMBtu to account for NGL sales. Of this potential \$10.85/MMBtu, estimated total GORTT take was only \$3.01/MMBtu (\$1.59/MMBtu from upstream and \$1.39/MMBtu from plant/NGL).

The taxation of LNG profits is an issue for any fob sales arrangement that permits full destination flexibility. Because the upstream sector is subject to higher resource taxation, governments typically try to maximise prices at the wellhead by minimising margins elsewhere along the value chain. Gas suppliers to the plant also have the incentive to ensure wellhead prices are as high as possible. In contrast, LNG offtakers wish to capture as much value as possible in offshore marketing operations in order to reduce / eliminate taxation. This is a particular issue for tolling-type structures, e.g. Trains 2 to 4, where the gas suppliers are also LNG offtakers and as such are motivated to minimise upstream take, to the detriment of the host country. From a government's perspective, this can be dealt with through ensuring that there is a competitive bidding process for LNG offtake or through agreements that the ultimate sales prices can audited.

10.2.2 ALNG Trains 2&3

10.2.2.1 Project Structure

The Train 2/3 expansion at ALNG saw the commercial arrangements evolve from a merchant plant for Train 1 to a quasi-tolling facility, as shown in Figure 10-5 and Figure 10-6. Train 2 delivered its first cargo in 2002 with Train 3 following in April 2003.

In terms of gas custody the trains have a merchant structure with ALNG 2/3 Co. buying gas and then selling. However, the FOB revenues are passed back upstream to the related gas supply contract, with the plant only receiving a fee (Plant Net Entitlement (PNE)) which is largely unrelated to the LNG price, i.e. a quasi-tolling basis.

Following the success of ALNG Train 1 it was clear that gas reserves were sufficient to justify the expansion of the project, which the upstream resource holders were keen to push forward. However, this proved difficult due to the conflicting interests of the partners in the project:

- BG had gained a right to supply half of the feedgas for Train 2 as part of the agreement for BP to supply 100% of Train 1. As the upstream resource holders, BP and BG were keen to develop their gas discoveries.
- BP and Repsol had announced a joint venture to develop a new import terminal in Spain (Bilbao) and intended to supply is with the production from Train 2.
- Repsol also wished to protect its position in Spain as the major shareholder in the state gas utility (Enagas / Gas Natural).
- Cabot had no particular need for more supply in its core US market.
- Cabot and NGC had relied on borrowing to fund Train 1, which was not yet on stream. As neither had a direct upstream interest, their main concern was to maximise the profit taken in the LNG plant.

These factors were likely to make the negotiation of the feed gas price very difficult under a replica of the structure of Train 1. Hence, the partners decided that a type of tolling structure would be the most efficient way to gain alignment to move forward with Trains 2 and 3.

Repsol had acquired a right to purchase 30% of BP's Trinidad reserves and was increasing its ownership, but its reserves ownership was less than its committed offtake. Therefore, a variation on a pure tolling structure was required, with Atlantic 2/3 purchasing feed gas from BP and delivering LNG to buyers selected by BP. Cabot and NGC agreed to withdraw from investing in Trains 2 and 3 in exchange for financial compensation.

Figure 10-5 ALNG Train 2 Physical / Financial Flows

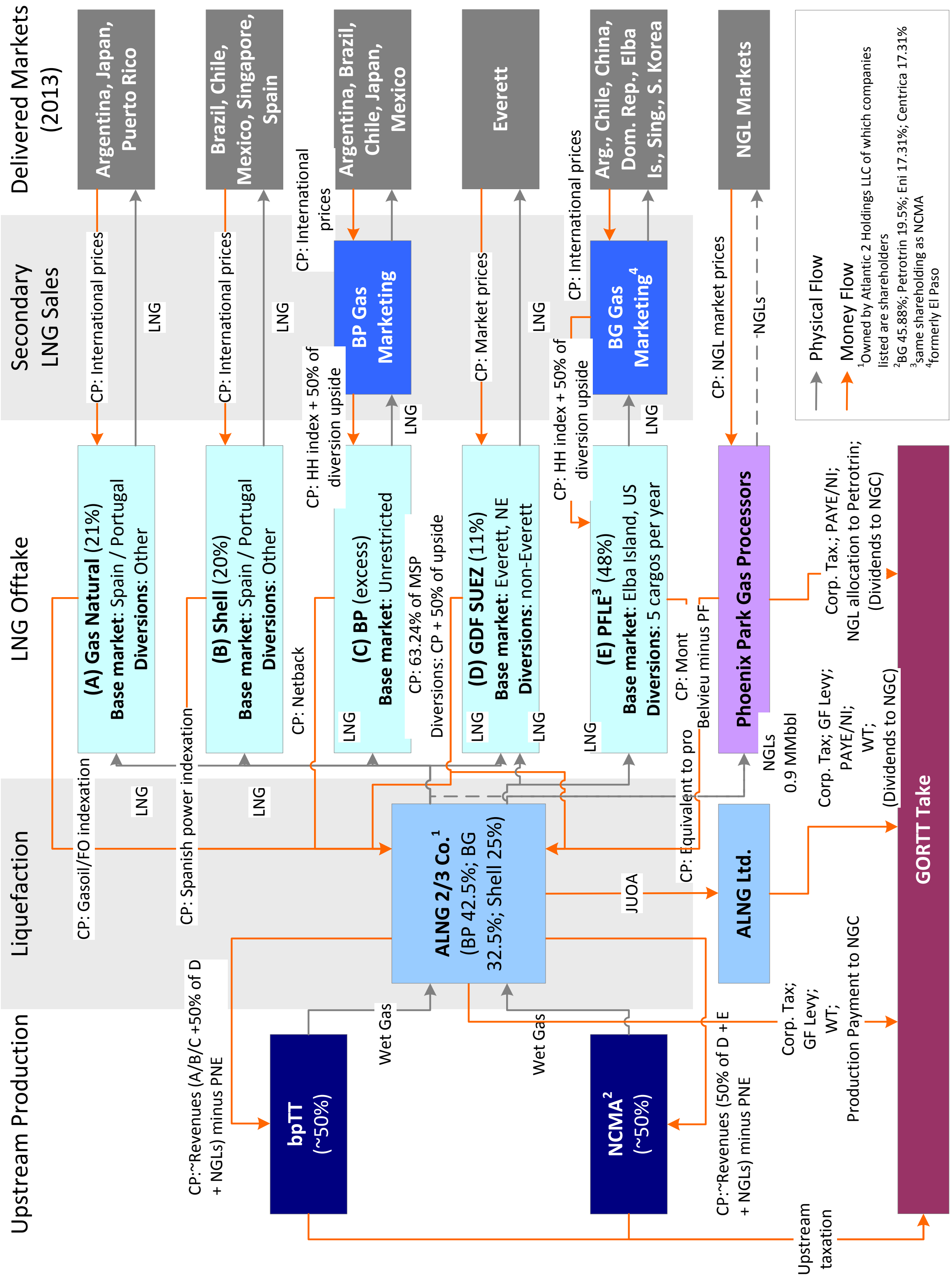
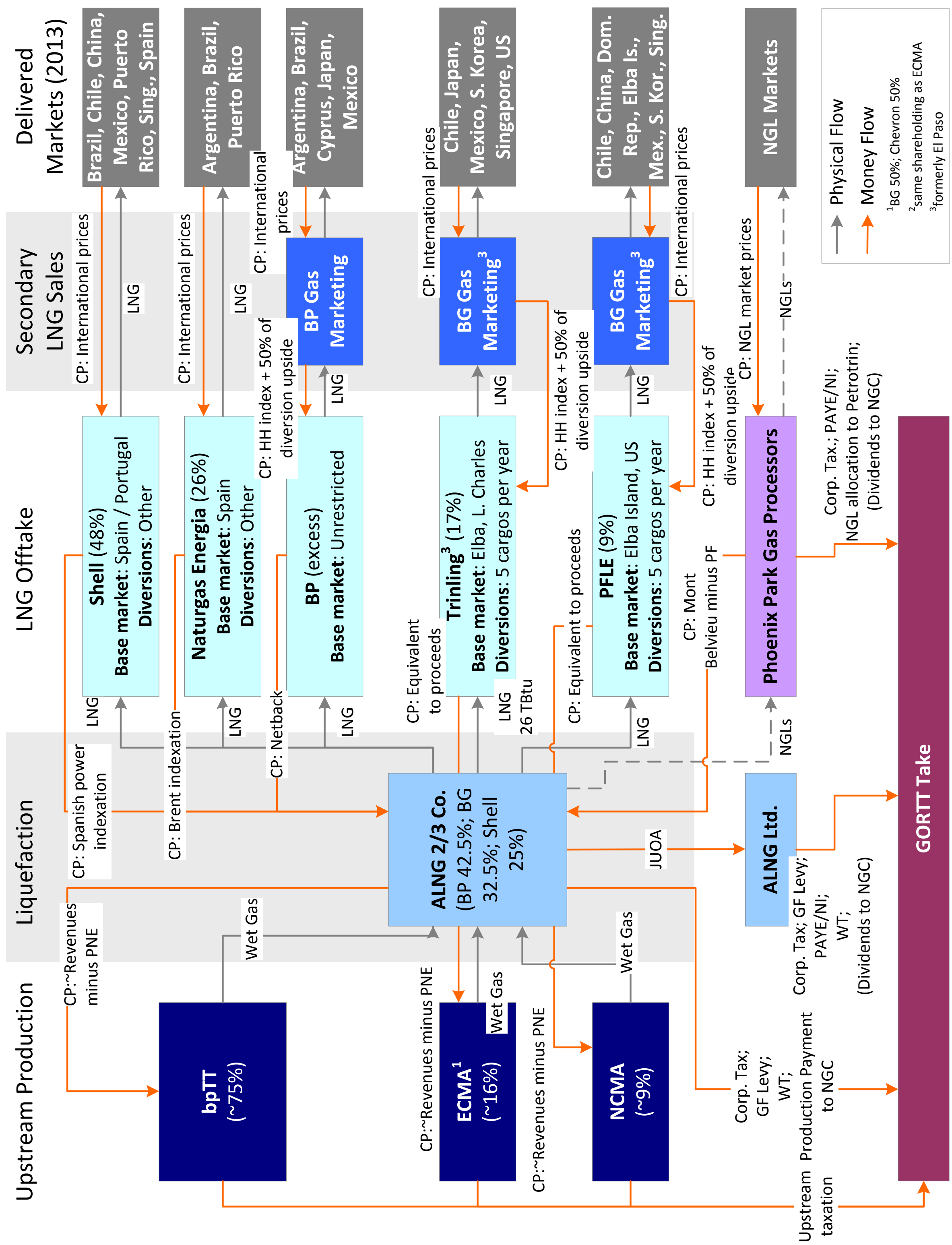


Figure 10-6 ALNG Train 3 Physical / Financial Flows



10.2.2.2 Marketing Arrangements & Netback Pricing

ALNG 2/3 Co. buys gas from bpTT and NCMA for Train 2 and bpTT, NCMA and ECMA for Train 3, and then sells LNG on an FOB basis under 20-year contracts to:

- Train 2: Gas Natural (formerly Enagas, 21%), Shell (formerly Repsol, 20%), GDF Suez (formerly Cabot, 11%), PFLE (same shareholders as NCMA, 48%) and BP (excess volumes).
- Train 3: Shell (48%), Naturgas Energia (26%), Trinling (same shareholders as ECMA, 17%), PFLE (9%), and BP (excess volumes).

The project also sells NGLs to PPGPL. The FOB LNG (and NGL) revenues are passed back upstream to the related gas supply contract, with the plant only retaining its PNE.

Key features of the LNG sales arrangements are as follows:

- Sales to Shell are based on indexation to Spanish power prices. There are no restrictions on Shell diverting to alternative markets and Shell is not required to share any of the upside it achieves on such diversions.
- Sales to Gas Natural are based on indexation to gasoil / fuel oil. There are no diversion restrictions or upside sharing. There were originally restrictions on sales outside Spain/Portugal but these were removed under LOAs signed in 2011 and 2014, which also revised the pricing indexation terms.
- Sales to GDF Suez have a similar basis to Train 1 although the base price is lower.
- Sales to Naturgas Energia are based on indexation to Brent with no diversion restrictions or upside sharing.
- PFLE / Trinling volumes were forward sold fully to El Paso on an FOB basis, based on HH pricing with 50/50 diversion upside sharing. El Paso was subsequently taken over by BG and the downstream contract is now with BG Gas Marketing. There were originally restrictions on diversions outside the US, but these were removed by agreement effective December 2008.
- BP volumes are forward sold fully to BP Gas Marketing on an FOB basis, based on HH pricing with 50/50 diversion upside sharing.

10.2.2.3 Realised Prices & Value Loss

The inlet gas prices and realised FOB LNG prices for Trains 2 and 3 are shown in the figures below.

Figure 10-7 ALNG Train 2: Plant Inlet Gas & Realised FOB LNG Prices

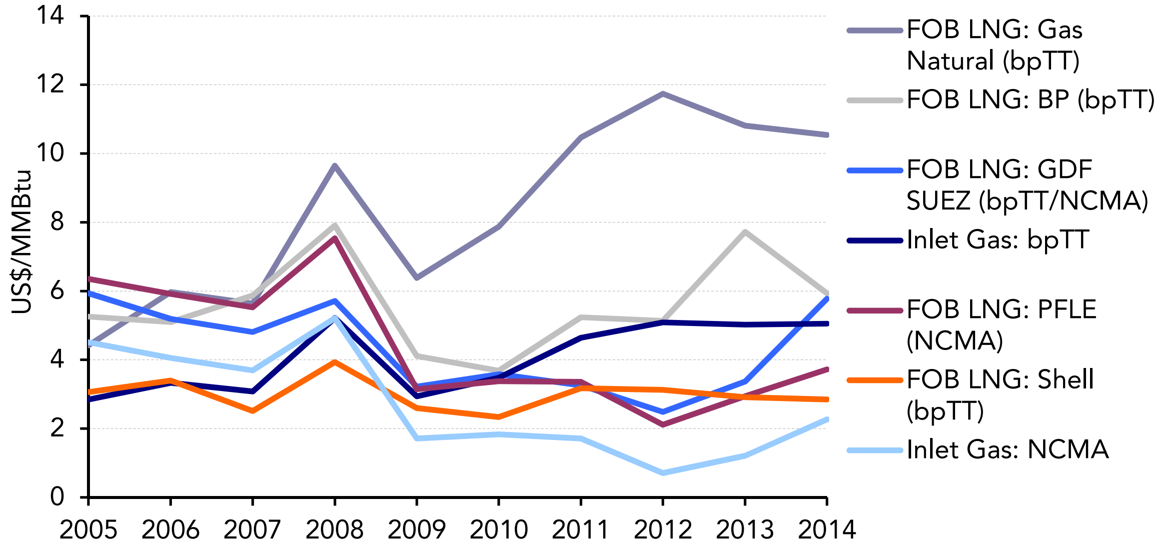
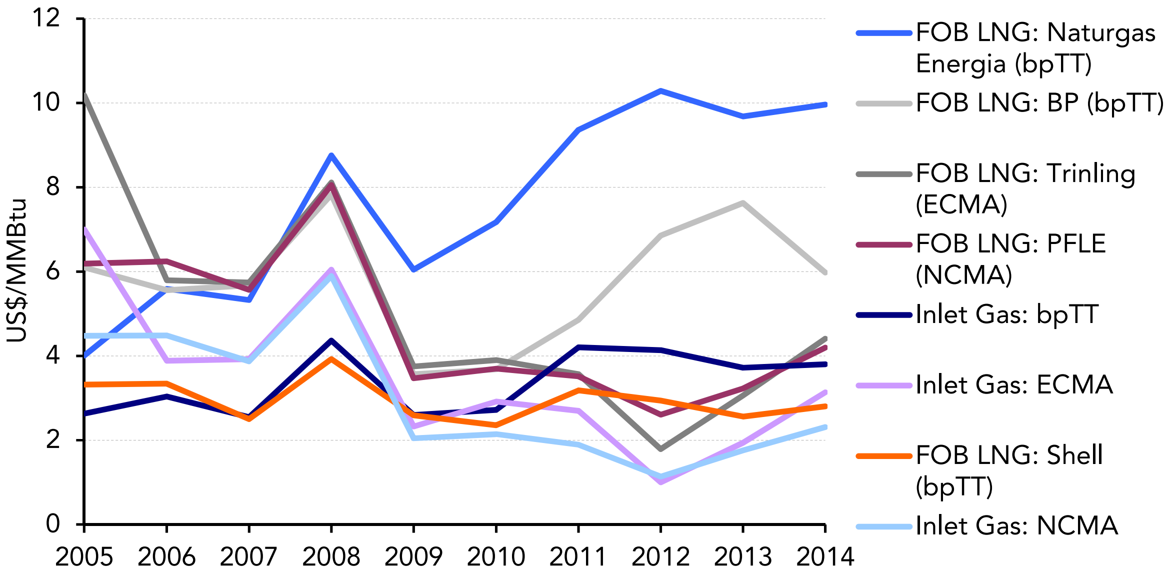


Figure 10-8 ALNG Train 3: Plant Inlet Gas & Realised FOB LNG Prices



The only sales contracts which have consistently realised relatively high prices over the period have been the oil / oil product-linked deals with Gas Natural (Train 2) and Naturgas Energia (Train 3). Pricing under a number of the other contracts has become very low over time, particularly the HH-linked deals entered into by PFLE / Trinling (Train 2 netback prices to the plant inlet for NCMA were as low as ~$0.70/MMBtu in 2012) and GDF Suez, and the Spanish power-linked deals with Shell. It should be noted that the HH-linked deals were significantly more attractive in the higher HH environment which existed prior to 2009. For example the PFLE Train 2 contract had an average FOB price of $7.53/MMBtu in 2008. By contrast, the Shell contracts had an average FOB price of less than $3/MMBtu over the decade.

As per the Train 1 analysis, the results of Poten's attempt to quantify the value loss in terms of FOB LNG prices under the existing LNG marketing / offtake arrangements for Trains 2 & 3 are illustrated in the figures below.

Figure 10-9 ALNG Train 2: Value Loss

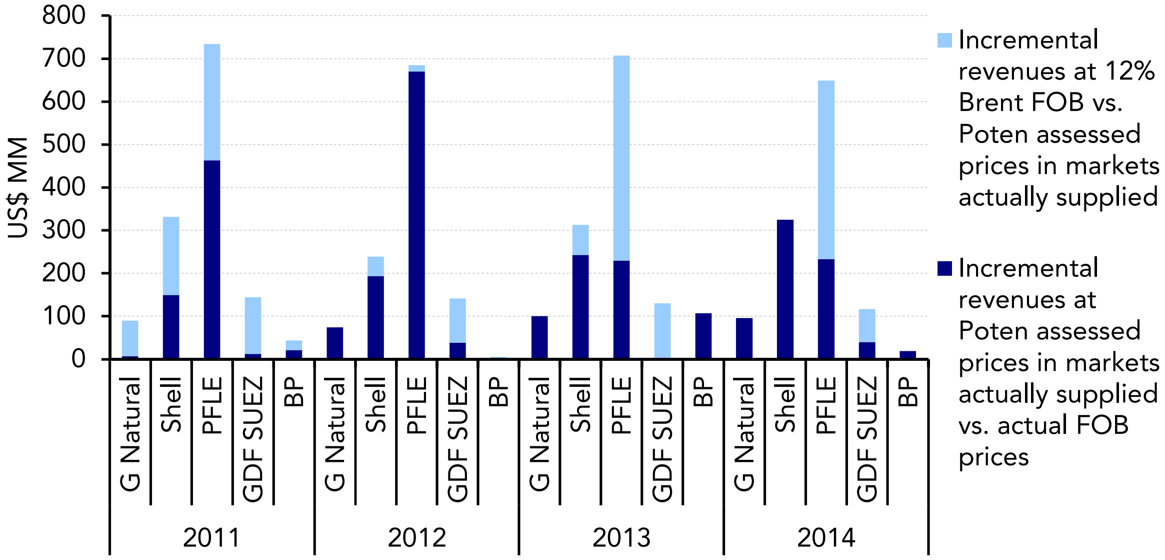
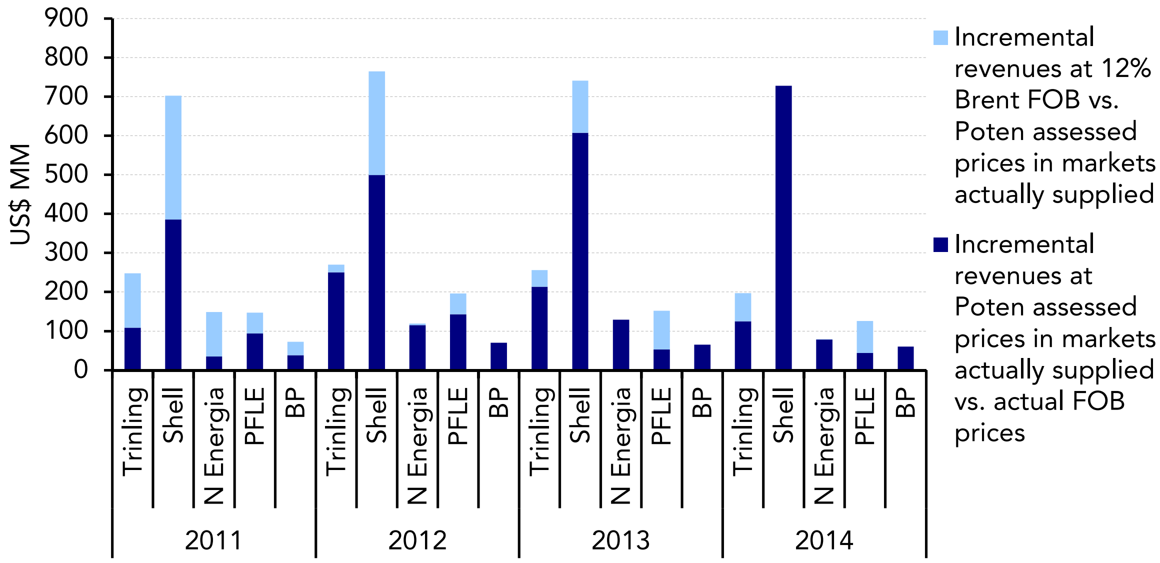


Figure 10-10 ALNG Train 3: Value Loss



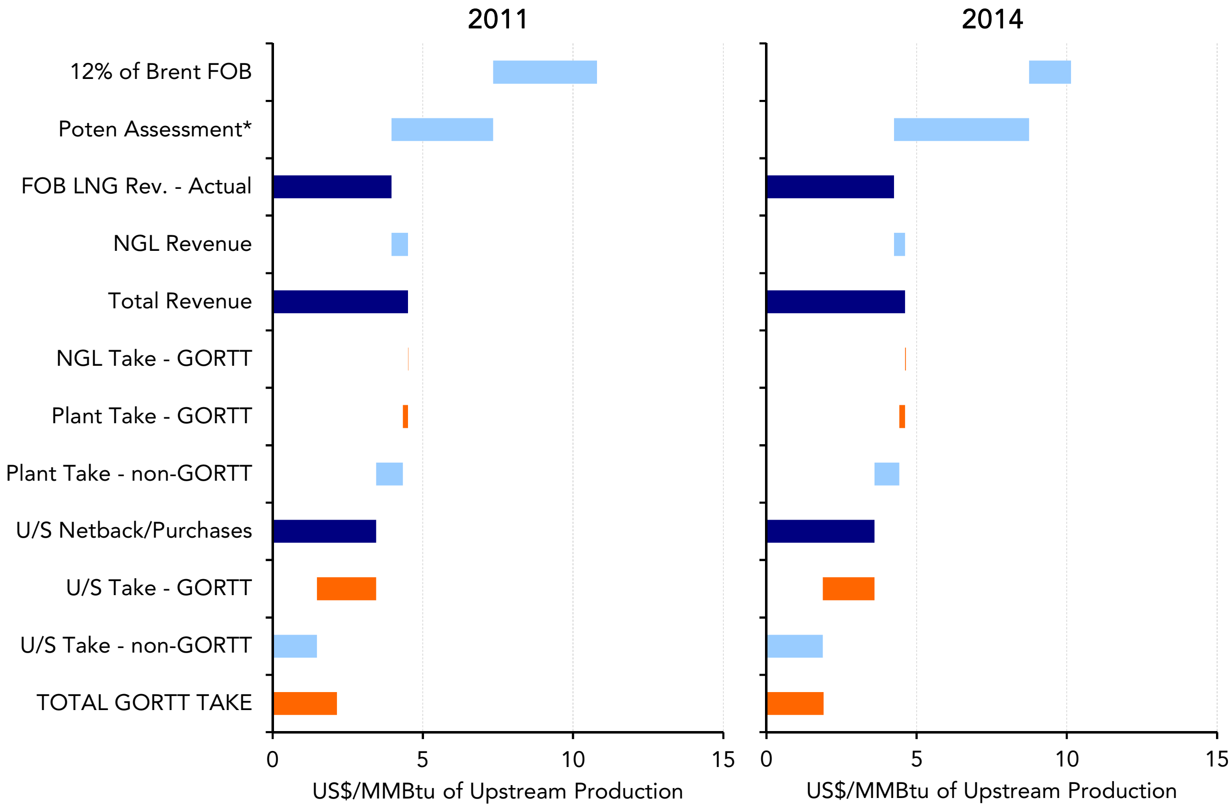
As would be expected from the FOB price assessment, the PFLE / Trinling and Shell contracts have resulted in significant value loss for ALNG. Although the PFLE / Trinling contracts with BG have a now low HH base price, they do have upside sharing when LNG is shipped to higher value markets. That said, BG has been shipping substantial volumes to Chile over recent times as a result of which ALNG has been realising relatively low netback prices. Poten's understanding is that the pricing under this contract into Chile is significantly lower than the pricing of some other of BG's long-term sales contracts. If BG were to ship LNG from T&T to higher value markets it would have to share the upside with upstream, which is not the case for some of its other global LNG purchase contracts. For example, BG has diverted nearly all of its cargoes from Equatorial Guinea to its Asian downstream contracts over recent years at much higher prices (often 14+% of crude oil) than it has realised in Chile. Our understanding is that it has to share very little of this upside revenue with the LNG project or government in Equatorial Guinea. Had BG supplied higher value markets and the revenues flowed fully back to T&T then additional FOB revenues under the BG contracts could have been over $1 billion per year higher.

In contrast to BG's utilisation of its Train 2/3 volumes, Shell has been diverting its supply to global markets at very high prices without any share of the diversion upside with ALNG. This has led to offshore value loss for ALNG which we estimate to be around $1 billion per year from 2011 to 2014 under the combined Shell Trains 2/3 contracts.

10.2.2.4 Revenue Waterfall / GORTT Take

As per the Train 1 analysis, Poten's assessment of the revenue waterfall for Train 2 & 3 for 2011 and 2014 is shown in the figure below.

Figure 10-11 ALNG Train 2 & 3 (combined): Revenue Waterfall / GORTT Take



*Poten assessed prices in markets actually supplied

Overall estimated GORTT take from the combined Train 2/3 has of late been lower than Train 1 at $1.93/MMBtu in 2014 (versus $3.01/MMBtu for Train 1). Upstream tax take has been slightly higher than Train 1 as the quasi-tolling structure flows more revenue back upstream, but GORTT take from the plant has been very low ($0.19/MMBtu in 2014) due to low Corporation Tax take and no NGC stake in the project.

As per Train 1 there has been a significant amount of value loss offshore either with LNG being supplied from T&T to relatively low value markets or high value markets being supplied but with the revenue not flowing back to T&T. Again taking 2014 as an example, overall FOB revenue at 12% of Brent would have been $10.14/MMBtu plus $0.37/MMBtu to account for NGL sales. Of this potential $10.51/MMBtu, total GORTT take was only $1.93/MMBtu.

10.2.3 ALNG Train 4

10.2.3.1 Project Structure

For Train 4, participants with upstream gas resources, BG and BP/Repsol, pressed for a pure tolling arrangement in order to lift LNG volumes in proportion to gas supply and minimise the value captured by the train itself (as per Trains 2 & 3). The tolling arrangement also allowed the sponsors to vertically integrate from the wellhead to downstream gas sales, including regasification capacity in the US market which was originally anticipated to be the destination for much of the LNG.

While this approach has great attraction to the producer, it is difficult for the government and tax authorities to grasp. Effectively there is a lack of arm's length gas sales or LNG transactions that can be used to establish value for taxation purposes. This led to prolonged negotiations between the shareholders and government, which delayed the start of construction of the plant.

Train 4 delivered its first LNG cargo in December 2005.

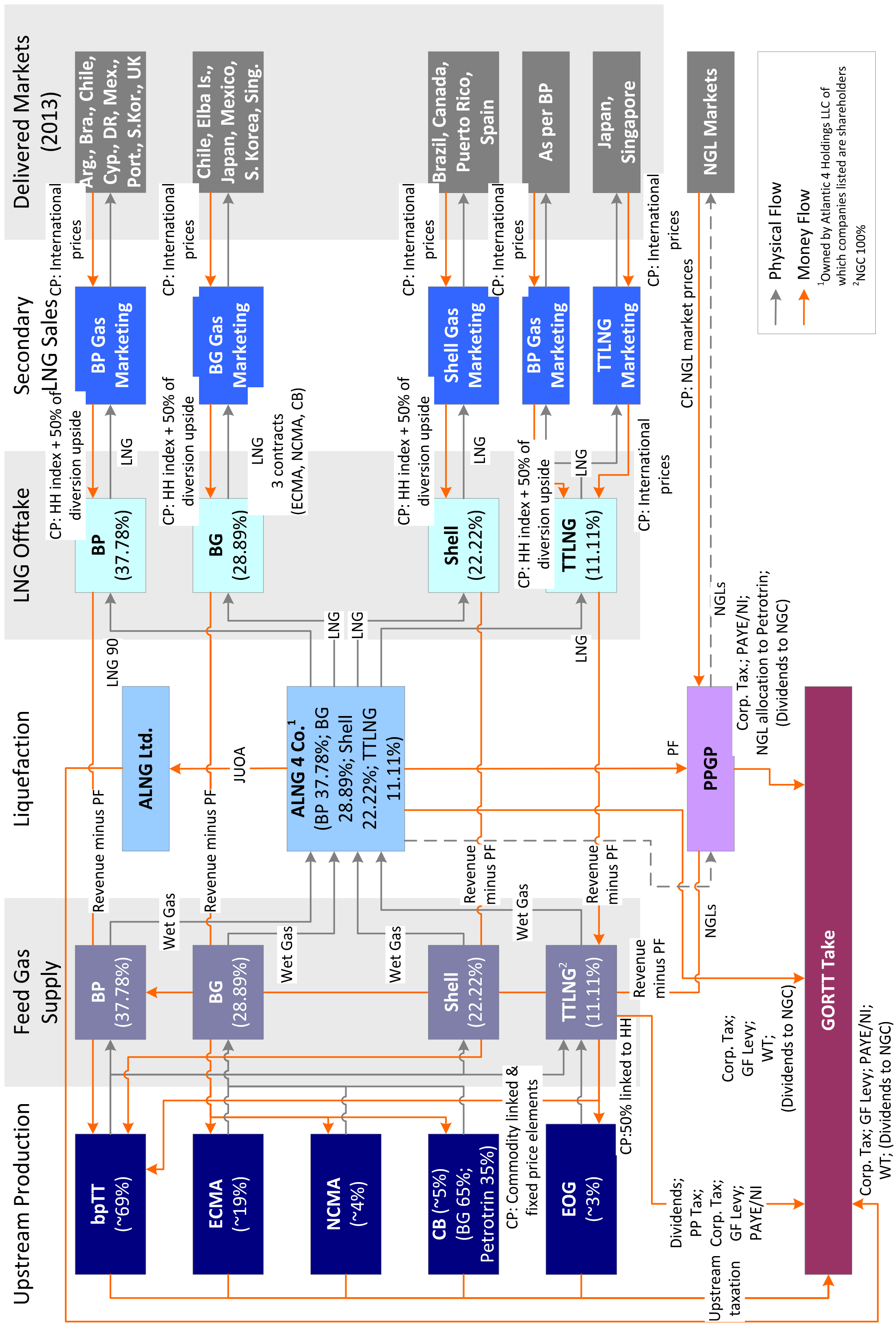
10.2.3.2 Marketing Arrangements & Netback Pricing

Shareholdings in Train 4 are BP 37.8%, BG 28.9%, Shell 22.2%, and NGC 11.1%. Gas supply / LNG offtake mirrors the shareholdings in the train, with Shell buying gas upstream of the plant from bpTT and NGC buying gas from bpTT and EOG.

The offtake arrangements for each of BP, BG and Shell involve FOB sales to a downstream marketing affiliate, with pricing based on indexation to HH +/- differentials depending on the location of the buyer's specified terminal capacity in the US. These sales arrangements with downstream entities also include complex pricing arrangements for revenue sharing when LNG cargoes are diverted away from the US market. Although the general principle is that incremental revenue minus additional costs is shared 50/50 between the marketing entity and the gas/LNG supplier, the application of costs to be subtracted from incremental revenues appears to be somewhat opaque. In addition GORTT does not have audit rights over these arrangements, which makes them very difficult to verify for reasonableness. For example, a number of the Train 4 cargoes to high value markets in 2014 realised lower FOB prices than Poten would have anticipated, even accounting for the 50/50 diversion upside split after incremental costs.

NGC entered into 2 agreements whereby its LNG offtake produced from EOG and bpTT gas was marketed by BP. NGC has subsequently terminated the agreement in relation to LNG from EOG gas, which it now markets itself, although BP still markets the LNG produced from bpTT gas.

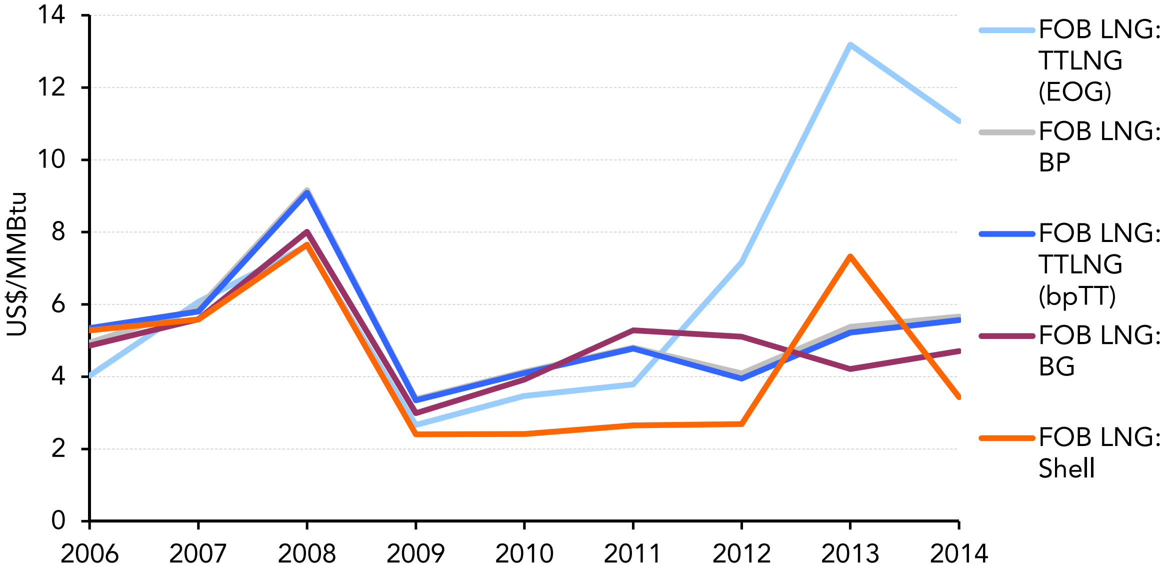
Figure 10-12 ALNG Train 4 Physical / Financial Flows



10.2.3.3 Realised Prices & Value Loss

The inlet gas prices and realised FOB LNG prices for Train 4 are shown in the figure below.

Figure 10-13 ALNG Train 4: Plant Inlet Gas & Realised FOB LNG Prices



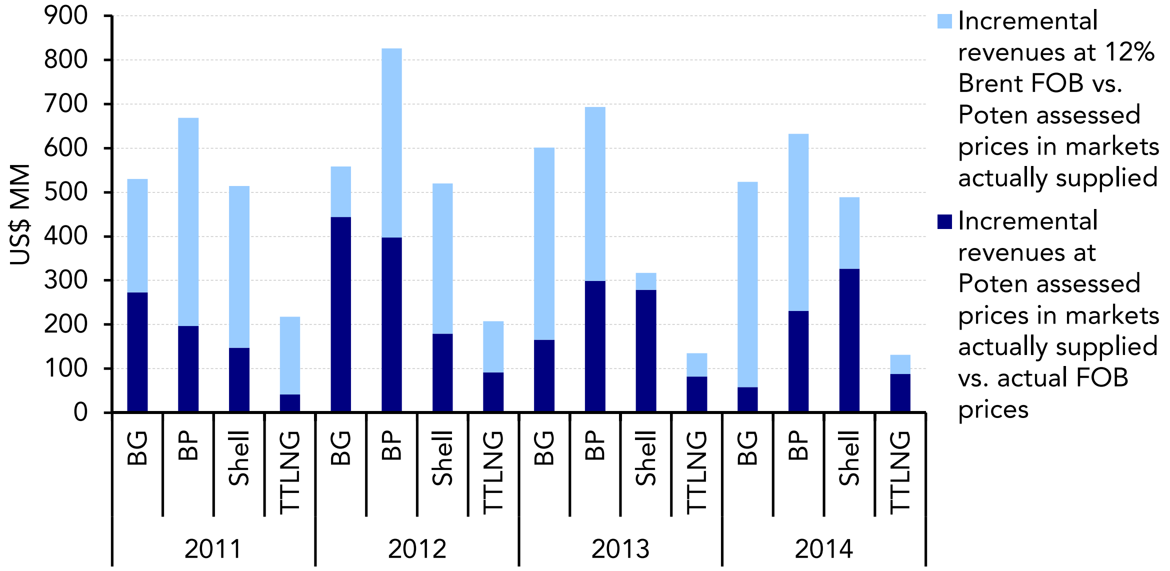
As would be expected with HH-linked contracts, there has been a sharp decline in realised FOB prices since 2008. However, at a time of historically high LNG prices, this should have been counteracted by upside sharing when offtakers diverted cargoes away from the US to higher value markets. This has not happened to the extent that may have been anticipated due to offtakers using their Train 4 volumes to service relatively low-priced downstream contracts in their portfolio, e.g.:

- As per Trains 2/3, BG has been supplying much of its Train 4 supply into Chile.
- As of 2014 Shell has been taking much of its supply from Train 4 into the Spanish market. As noted previously it has been shipping Train 2/3 volumes to higher value markets as it does not have to share the upside on them and when it does have to share the upside, i.e. Train 4, supplying lower value markets to maximise its take at the expense of the FOB prices realised by T&T. From the perspective of T&T this situation worsened markedly following the Shell takeover of Repsol at the end of 2013. In 2013 Repsol realised an average FOB price of $7.33/MMBtu as it was supplying significant volumes to the high-priced Brazilian market. In contrast Shell's average 2014 FOB price was $3.43/MMBtu at a time of similarly high global LNG prices.
- BP has been supplying numerous cargoes into relatively low-priced markets at low prices, particularly the Dominican Republic, although this has improved somewhat over time (average FOB price of $5.67/MMBtu in 2014 versus $4.13/MMBtu in 2010).

As per Trains 1 to 3, this is illustrated in the value loss analysis (see Figure 10-14).

The obvious exception is the sales price achieved by TTLNG for its LNG from EOG gas in 2013 and 2014. These very high prices (average $13.19/MMBtu in 2013 and $11.08/MMBtu in 2014) are indicative of what was achievable once its marketing arrangements with BP for these volumes were terminated. In comparison its marketing arrangements with BP are still in place for the LNG from bpTT gas and as a result it continues to realise far lower prices under this arrangement (average $5.22/MMBtu in 2013 and $5.57/MMBtu in 2014).

Figure 10-14 ALNG Train 4: Value Loss



As would be expected by the low FOB prices, value loss has been significant across all of the contracts. Admittedly with the benefit of hindsight, it has proven to be very costly for T&T to lock in its sales from Train 4 to HH pricing via marketing arrangements with downstream entities of the various offtakers. This has resulted in massive value capture by these entities which falls outside the T&T tax net, which we estimate to have exceeded $1.7 billion each year from 2011 to 2014.

The general principle under tolling arrangements is that the revenue actually realised flows back to the upstream to maximise the take there. Inserting the marketing intermediaries negated this and provided the offtakers with a "no lose" situation:

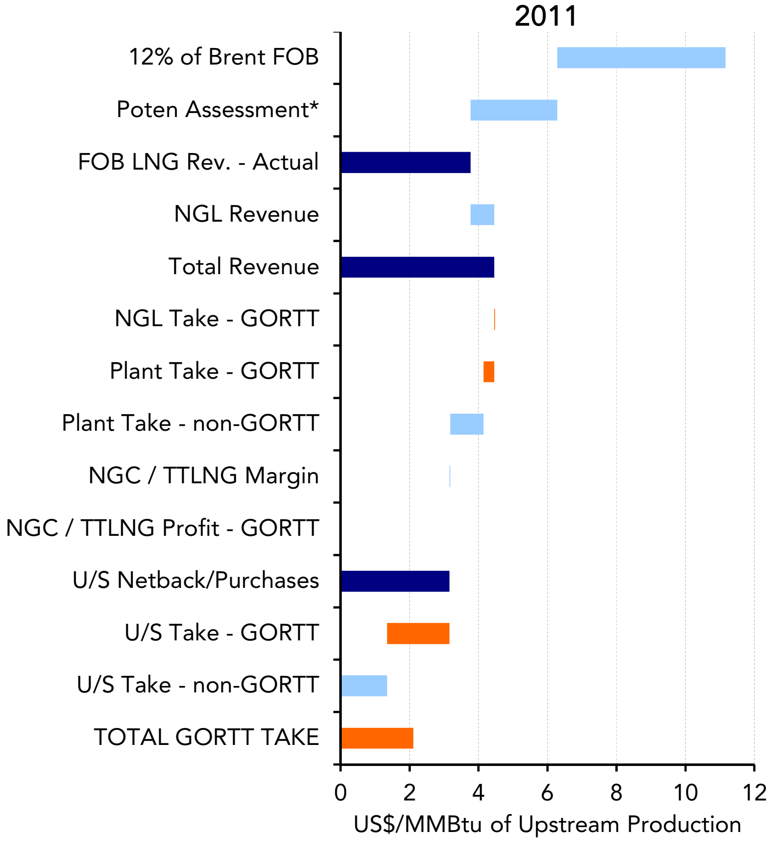
- If the US had remained the most attractive LNG market then the LNG would have continued to flow there with pricing netted back to T&T and the offtakers making a guaranteed margin.
- The US is now no longer an attractive market for LNG but T&T is stuck with HH as a base price under these marketing arrangements, with the majority of the actual sales revenue now being captured by the marketing entities offshore.

Had a pure tolling structure with no marketing arrangements or base price been in place then T&T would have been protected from the change in market situation vis-à-vis the US and would have benefitted from the very high global LNG prices over the past 5 years. T&T could also have been protected had there been some sort of contractual provision to revisit the pricing mechanism in the event of significant changes to the global LNG market.

10.2.3.4 Revenue Waterfall / GORTT Take

As per the analysis for Trains 1-3, Poten's assessment of the revenue waterfall for Train 4 for both 2011 and 2014 is shown in the figure below.

Figure 10-15 ALNG Train 4: Revenue Waterfall / GORTT Take



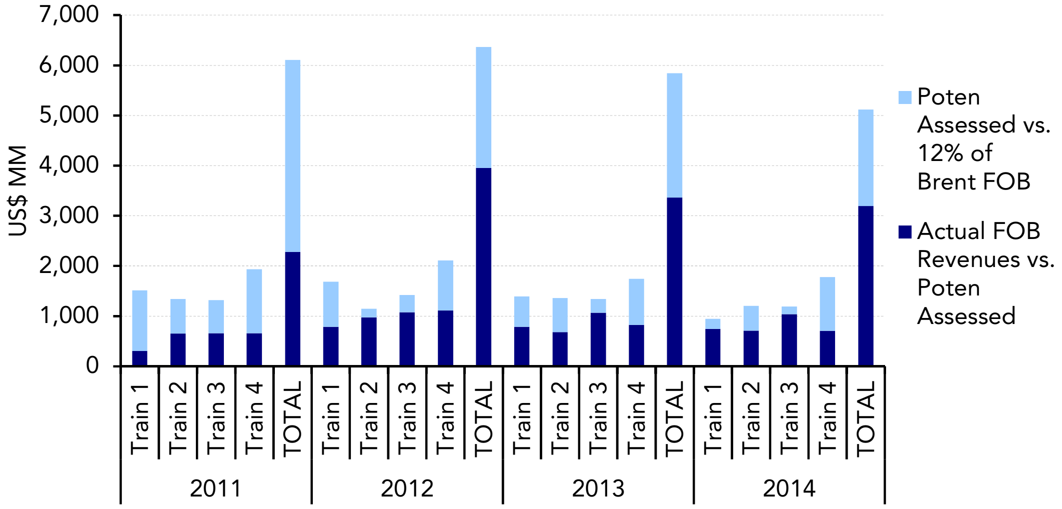
*Poten assessed prices in markets actually supplied

Overall GORTT take from Train 4 was $2.22/MMBtu in 2014, higher than Train 2/3 ($1.93/MMBtu) but significantly less than Train 1 ($3.01/MMBtu). Upstream GORTT take was similar to Train 1 at ~$1.5/MMBtu in 2014 but GORTT take from the plant was only around $0.30/MMBtu. As a further illustration of the value loss discussed above, overall FOB revenue at 12% of Brent would have been ~$10.86/MMBtu plus ~$0.45/MMBtu to account for NGL sales. Of this potential $11.30/MMBtu, total GORTT take was only ~$1.80, i.e. around 15%.

10.2.4 Combined Value Loss from LNG

Poten's estimate of the combined potential value loss from the four ALNG trains averaged around $6 billion per year between 2011 and 2014, as shown in the figure below.

Figure 10-16 Combined ALNG Value Loss



10.2.5 Review of LNG Marketing Arrangements

The analysis in this section clearly demonstrates that the existing arrangements are not optimally capturing value for T&T. The quantum of the value loss for T&T from an industry which consumes over half of its gas production is clearly of the utmost concern. It is always easy with the benefit of hindsight to look back at things that should have been handled differently in signed contracts and to a large extent T&T will simply have to live with the terms that have been agreed for LNG offtake. Nevertheless, there are approaches which could be taken to try and increase the value flowing back to T&T from the existing contractual arrangements, although these may be uncomfortable and will require strong political will to execute:

- Stimulate LNG offtakers into action by putting the reality of T&T's take from the LNG industry into the public domain, or at least threatening to do so.
  - The general perception in T&T appears to be that LNG provides very good value for T&T's gas and there does not appear to be any widespread awareness of the value loss issues that have been described in this section. As well as being LNG offtakers, BP and BG are also major upstream players in T&T and frequently talk up T&T as a key investment area for them. Many of the IOC's are generally very sensitive about their corporate reputation and may be persuaded to change their approach by negative publicity or the threat of this, particularly those with a substantial domestic position in T&T.
  - Although the analogues with T&T may be questioned, this approach has been successfully taken by countries including Indonesia (raised the oil indexation cap on its supply contract into China from Tangguh even before the contract has started), Equatorial Guinea (put pressure on BG to extract some element of diversion upside sharing from BG) and Yemen (managed to extract some price concessions from offtakers that were not mandated in its LNG SPAs).

- Tax authority action on realised prices.
  - The Petroleum Pricing Committee has been identified as a potential mechanism to impose deemed pricing for tax purposes, bringing more revenue under the GORTT tax umbrella. This needs to be investigated further by MEEA.

- Action based on terms of project contracts, e.g. Project Agreements.
  - There may be terms in the Project Agreements for the various LNG trains under which action could be taken to change the approach of various LNG offtakers, e.g. a requirement to maximise value under the LNG offtake arrangements. This needs to be investigated further by MEEA.

- Closely scrutinise future LNG sales to attempt to better hold offtakers to account.
  - MEEA currently receives cargo-by-cargo data from ALNG on sales from ALNG Trains 1-3. However, this data is not reconciled with the later adjustments made as a result of cargo diversion income. MEEA should insist that all ALNG revenue is reconciled on a cargo-by-cargo basis in the data that it receives, so that it can be properly understood and evaluated. MEEA should also insist that any costs included in the LNG prices are fully itemised and explained such that they can be properly scrutinised.
  - MEEA should undertake ongoing analysis of this data as it is received to understand where the main areas of value loss are versus prevailing market conditions, i.e. which offtakers, which contracts, which end markets etc. This will put MEEA into a stronger position to challenge the activities of the offtakers and possibly prompt revised marketing behavior that is more in the interests of T&T.

It is clear that the outcome of following any of these approaches remains open to question. In addition, it will be necessary for GORTT to take legal advice on the extent to which action based on project contracts or by the tax authority are likely to succeed.

10.3 NGC-SUPPLIED INDUSTRIES

10.3.1 Methanol

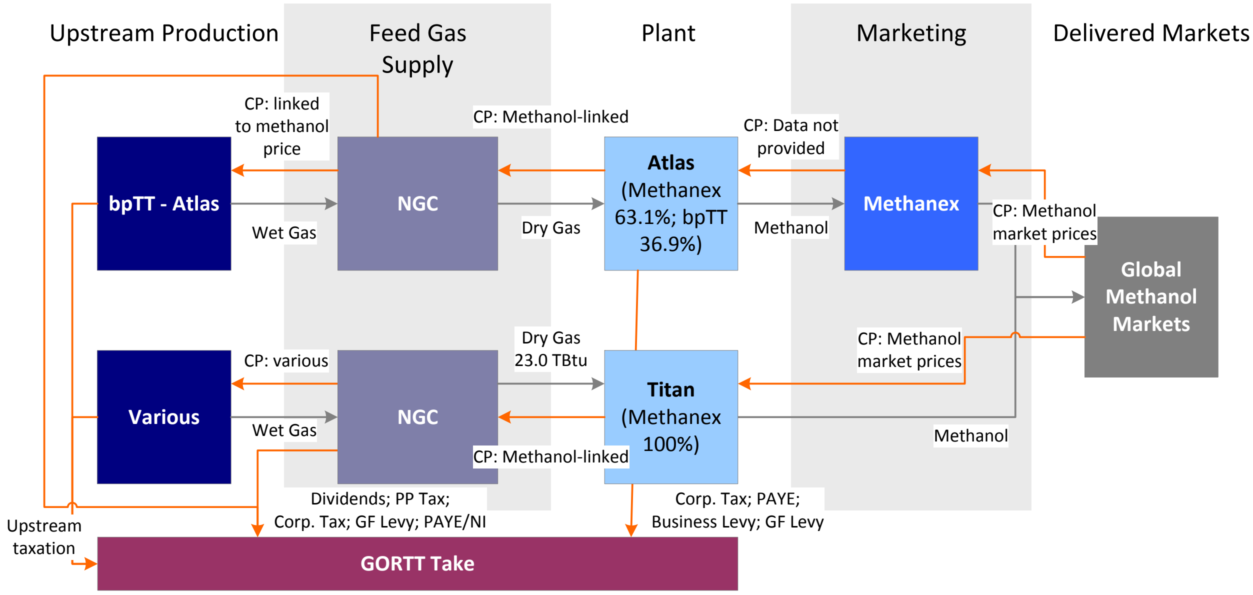
10.3.1.1 Project Structure

The methanol projects have a more straightforward, and largely uniform, structure than the LNG projects. An example is provided in Figure 10-17 for the two Methanex projects. Graphics for the other methanol plants are provided in Appendix I. NGC purchases wet gas from upstream producers and then sells dry gas as feedstock to the methanol plants. NGC's wet gas is processed by PPGPL which extracts the NGLs 4and sells them on the market.

The two Methanex projects are slightly different in in terms of gas supply structure:

- Atlas, in which BP is a shareholder, is tied to a specific gas supply contract between bpTT and NGC, i.e. although NGC purchases the gas from bpTT and sells it to Atlas it does not take volume risk on gas supply.
- Titan, which is wholly owned by Methanex, buys gas from NGC but this gas comes from NGC's general supply portfolio rather than being tied to any specific source of gas supply.

Figure 10-17 Methanol Plant (Methanex Example) Physical / Financial Flows



10.3.1.2 Marketing Arrangements

The marketing of T&T's methanol and ammonia production is handled by some of the largest operating companies in the respective businesses. These companies have global reach in their marketing.

Generally, the companies responsible for marketing the product have supply/offtake contracts with the producing company including exclusive long-term supply contracts. The terms of the offtake agreements are commercially confidential and transfer pricing is not transparent. However, the ownership structures of the companies ensure that in many cases offtake agreements have been negotiated on at least a semi-arm's length basis between separate entities (albeit with overlapping cross-ownership across the parties).

Price discovery is readily available in both the ammonia and methanol markets, with several independent price reporters publishing assessments for regional ammonia and methanol prices.

Methanex

Methanex is responsible for the marketing of product from its 100% owned Titan plant and the Atlas plant jointly owned with bpTT, accounting for around 40% of Trinidad's methanol production. The Canadian company, headquartered in Vancouver, is the largest player in the global methanol market. In addition to its T&T plants, Methanex has production facilities in USA, Canada, Chile, Egypt and New Zealand. It has an extensive global supply chain and distribution network of terminals and storage facilities throughout North America, Asia Pacific, Europe and South America. Its wholly-owned subsidiary, Waterfront Shipping, operates the largest methanol ocean tanker fleet in the world, consisting of seventeen vessels. It is understood that around 30 % of output is marketed at a fixed price to the offtaker, and all production can enter Europe and North America on a duty free basis. North America, Asia Pacific, Europe and Latin America are the main destinations.

MHTL

Methanol Holdings Trinidad Limited (MHTL) is the largest producer of methanol in T&T, with around 4 MMt/y of production capacity marketed under the MHTL umbrella (approx. 60% of T&T's total). It is responsible for marketing the methanol from the Trinidad and Tobago Methanol Company (TTMC), Caribbean Methanol Company Limited (CMC), Methanol IV Company Limited (MIV) and the M5000 plant. MHTL markets its products through Helm AG, a major petrochemical marketing and distribution company based in Germany. Helm sells to the North American market through the Caribbean Petrochemical Company (CPC) which has contracts with the North American petrochemical distributor Southern Chemical Corporation (SCC) for the sale of methanol into that market. Helm itself covers the European and Asian markets. Helm and SCC are also responsible for the marketing of ammonia, UAN solution and melamine products from the AUM complex.

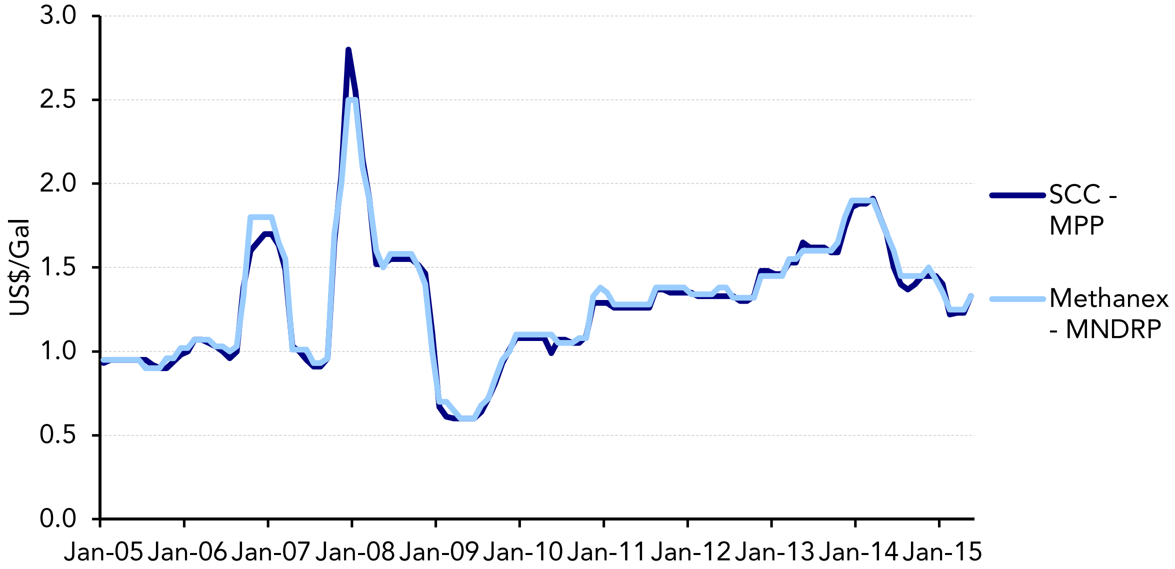
MHTL is 100% owned by Consolidated Energy Limited (CEL), which is headquartered in Barbados with its ultimate parent company Proman AG based in Switzerland. According to research from Moody's, MHTL will be able to increase its geographic diversification after the expiration, in June 2015, of a low-margin contract with its largest customer that will allow it to reallocate close to 1 million tonnes of methanol at higher margins. The global supply chain logistics are managed by MHTL's marketing department in Point Lisas for Global Marketing Strategy, Market Intelligence, Shipping and Distribution, Global Marketing Operations. MHTL operates/manages a fleet of nine dedicated methanol tankers and three UAN tankers. It has storage and distribution facilities in the major markets of North America and Europe. MHTL through its 60% shareholding interest in the Oman Methanol Company is also able to expand its distribution network to the Far East and Asian markets.

10.3.1.3 Price Reporting

The two major producers/marketers of T&T methanol to North American markets (Methanex and SCC) publish monthly posted contract prices for methanol FOB USGC. Methanex publishes its Non-Discounted Reference Contract Price (MNDRP) while SCC publishes a Monthly Posted Price (MPP). Price reporters including Jim Jordan and Associates (JJA, part of Argus), ICIS and Platts publish spot methanol prices and effective contract prices based on their assessment of market, including the real price achieved after marketing discounts are applied to the posted contract prices.

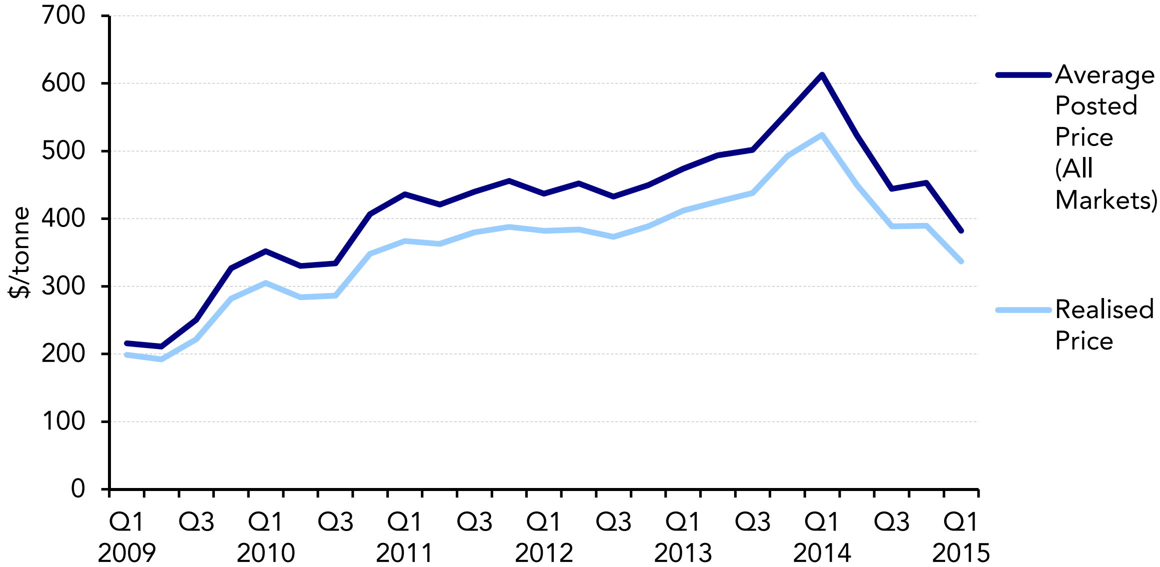
Posted contract prices for Methanex and SCC track each other closely as is to be expected and are often identical from month to month as shown in Figure 10-18.

Figure 10-18 Methanol Posted Contract Prices - Southern Chemical and Methanex
(Source: SCC, Methanex)



According to its financial reports, the realised price that Methanex achieved from its sales was around 14% lower than its average posted contract price during 2014, as shown in the figure below.

Figure 10-19 Methanex Realised Prices v Posted Contract Prices
(Source: Methanex)



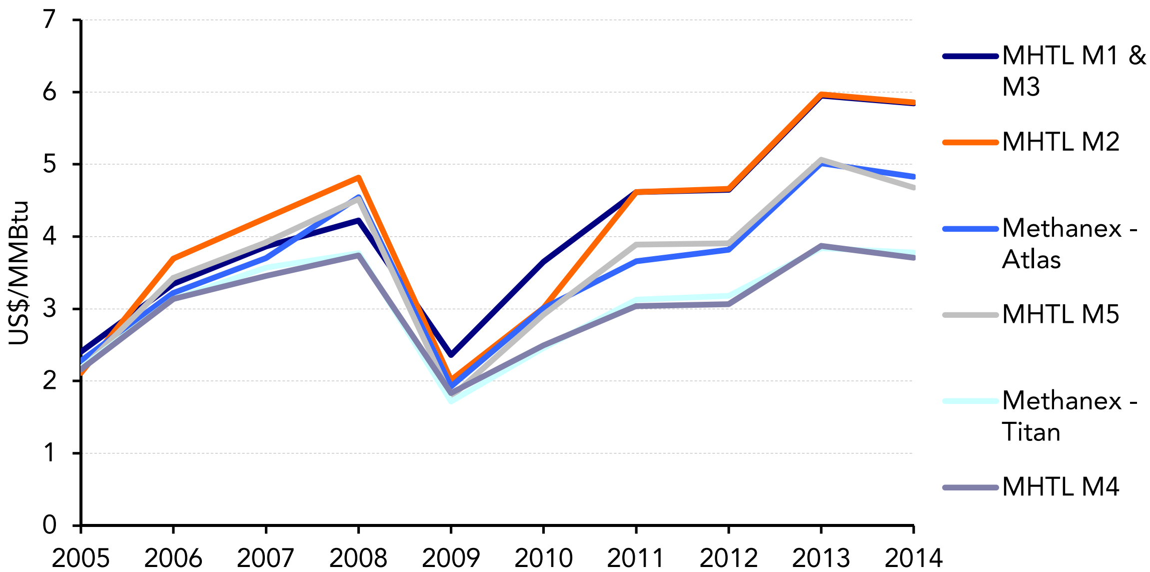
10.3.2 Realised Gas Prices

NGC uses a product-related pricing mechanism for its ammonia and methanol-producing customers. The pricing mechanism follows the format of a base gas price tied to an ammonia or methanol price with the base gas price increasing when the actual commodity price increases. The gas price also decreases when commodity prices fall, but we understand is generally subject to a floor price linked to an annual escalator. This mechanism allows for the sharing of risk and reward between NGC and the plant where in times of low commodity prices the plant can continue to operate economically, and in a high price environment the plant can afford to pay much higher gas prices.

We also understand that a number of the contracts supplying gas to petrochemical plants have netback pricing mechanisms with multiple slopes, i.e. the price relationship between the gas price and the product price increases once the product price exceeds a kink point. This mechanism allows T&T to get the benefit of high pricing or spiking in the particular commodity market. Some of the contracts are understood to have up to 5 kink points in the price formulae.

The average annual gas prices paid by the methanol producers are shown in the figure below.

Figure 10-20 Methanol: Gas Prices Paid to NGC



As the methanol plants buy gas from NGC on a methanol price-linked basis, it is unsurprising that gas prices paid to NGC tracked up with the methanol price between 2009 and 2014. The disparities between the prices paid to NGC by the different plants are simply a function of the individual contractual price indexation provisions that were agreed between NGC and the methanol producer. Poten has not been provided with details of these price mechanisms, although it is possible to derive close correlations to methanol price movements from the data provided.

The methanol price used by NGC to calculate its methanol-linked gas prices is derived by deducting a discount factor ranging from 8% to 12% as well as estimated freight costs from the average of international methanol market prices. This average price is weighted by volume of methanol shipped and sold into the relevant markets. At this time the main markets are North America, Europe and Asia. there is no FOB Caribbean reference.

The data sources used for deriving methanol prices are: IHS/CMAI, ICIS, Argus/JJ&A and Platts Petrochemical Scan. Freight rates are provided by SPI Marine/Soundtanker and Solmar Universal charterers. The petrochemical customers provide their shipment data on a monthly basis.

The basic formula to arrive at the average methanol price is:

$$MRP = (K*[Prt2*V1 + Pusg*V2 + Poth*V3] - FAV)/V$$

Where:

- K is the discount factor
- Prt2 is the Europe methanol price for methanol sold to European markets, e.g. Hull (UK), Rotterdam (Netherlands) and Rouen (France)
- Pusg is the US Gulf price for methanol sold to North America markets, e.g. Houston (US), Quebec (Canada) and Pajaritos (Mexico).
- Poth is the methanol price the customer receives for methanol sold in any other destinations not covered in Prt2 and Pusg, e.g. Asia or South America.
- V1, V2 and V3 are the volumes of methanol sold to European, US and Other markets respectively.
- V is the total volume of methanol shipped and sold monthly by the customer.
- FAV is the average freight rate weighted by volumes shipped to relevant destinations

The netback methanol price, now FOB Trinidad or FOB Point Lisas basis is then applied to the gas pricing formula.

$$P = Po + Af * (M - MRP)$$

Where :-

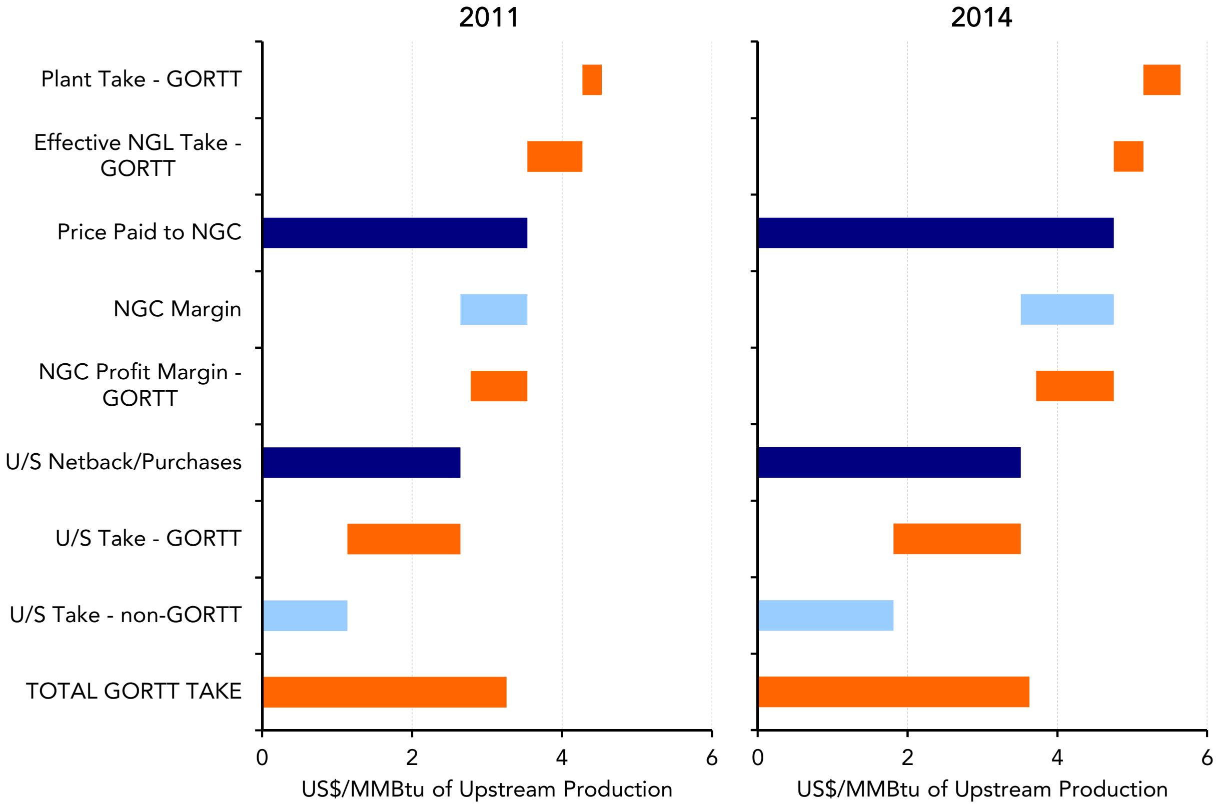
- P : Gas Price
- Po: Gas Base Price
- Af: Adjustment Factor
- MRP: Methanol Reference Price
- M: Actual Methanol Price

NGC shares in any upside when the methanol product price exceeds the reference price.

10.3.2.1 Revenue Waterfall / GORTT Take

As per the LNG analysis, Poten's assessment of the revenue waterfall for Methanex Atlas, as a representative example of the Methanol plants in general, is shown in the figure below.

Figure 10-21 Methanex Atlas: Revenue Waterfall / GORTT Take



In addition to the GORTT take from the upstream gas supply and the plant taxation, the analysis also takes into account the benefit that GORTT derives from the NGLs that are extracted from the gas by PPGPL before it is supplied by NGC to the end users, as well as NGC's profit margin on gas purchases / sales.

Overall GORTT take from the project was $3.63/MMBtu in 2014, consisting of:

- Plant take: $0.50/MMBtu
- Effective NGL take: $0.40/MMBtu
- NGC profit margin: $1.04/MMBtu
- Upstream take: $1.70/MMBtu

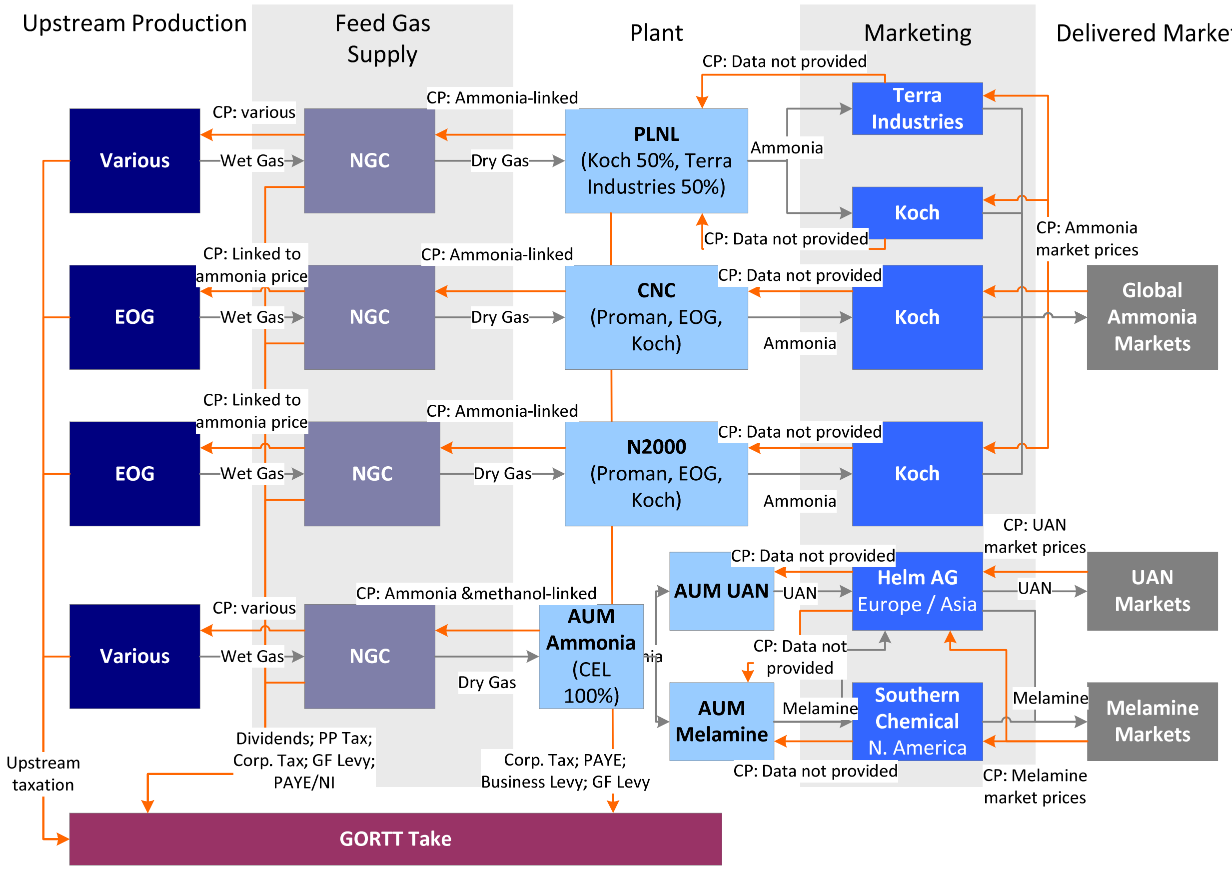
Although plant take and upstream take are also generally higher, it is largely NGC's profit margin and the effective NGL take which account for the higher overall GORTT take than for LNG.

10.3.3 Ammonia

10.3.3.1 Project Structure

The ammonia projects operate under the same structures as the methanol projects, with producers buying gas from NGC. As per Methanex Atlas, some of the ammonia plants (CNC, N2000) have gas supply tied to specific upstream supply contracts, with the remainder supplied from the general NGC portfolio. An example is provided in Figure 10-22 for a number of the ammonia plants. Graphics for the other ammonia plants are provided in Appendix I.

Figure 10-22 Ammonia Plant (Various Examples) Physical / Financial Flows



10.3.3.2 Marketing Arrangements

Yara International

Yara International ASA (formerly Norsk Hydro) is responsible for marketing production from the Yara facility and Tringen's plants (Tringen I & II) for which it provides marketing support through sales agency agreements. Tringen's ammonia complex is also managed and operated by Yara under a management and operating agreement. Yara is the largest trader of ammonia in the world with production of just over 7.0 MMt and sales of 2.9 MMt in 2014. Yara has been growing its business in Latin America with the acquisition of fertilizer production facilities and distribution regionally.

Yara's ammonia shipping is covered by its own fleet with a mix of fully-owned, JV-owned and long-term time chartered ships. Its main traditional markets are North America and Europe, but it sees growth markets in China, India and Brazil. In addition to Trinidad, Yara has competitive sourcing of product from Middle East/Qatar (through its ownership of Qafco), Australia and North Africa.

Potash Corp. (PCS)

PCS operates four ammonia plants and one urea plant in Point Lisas. Combined capacity for its ammonia plants is around 2.2 MMt/y of ammonia and 0.8 MMt/y of urea. Around 20% of ammonia production is consumed in urea production, with the remainder sold primarily to monoammonium phosphate (MAP) and diammonium phosphate (DAP) producers in the US Gulf Coast, Florida and North Carolina. MAP/DAP are major solid phosphate fertilizers. PotashCorp uses approximately one-third of its ammonia output at its own phosphate plants.

CNC and N2000

The CNC and N2000 plants are owned by Proman, Koch and EOG. Ammonia production from CNC and N2000 is marketed by Koch under an offtake contract based on Fertecon and FMB (Argus) prices. Koch is responsible for marketing the ammonia offtake. The main market is the United States where Koch has ammonia and derivatives production and marketing operations. Liquid anhydrous ammonia can be offloaded at NOLA (New Orleans, Louisiana) and transported in the ammonia pipeline system operated by NuStar to ammonia distribution terminals and production facilities across the Midwest of the US.

Point Lisas Nitrogen (PLNL)

Point Lisas Nitrogen Limited (PLNL) is owned 50:50 by Koch Industries and CF Industries. CF Industries and Koch are some of the world's largest manufacturers and distributors of nitrogen fertilisers. Marketing is handled by the two companies, with the US as the main market where Koch and CF Industries have ammonia and derivatives production and marketing capabilities. CF Industries is the largest nitrogen producer in North America; it has ammonia production capacity of 7 MMt/y plus urea, UAN and ammonium nitrate production. It is currently expanding production at its main site in Donaldsonville in the US.

10.3.3.3 Price Reporting

Ammonia is a globally-traded commodity chemical. Independent price quotes for global ammonia prices market prices including fob Caribbean quotes are reported by Fertecon, FMB and Green Markets. Average prices from these market reporters are used in calculating input gas prices for ammonia producers and these price quotes are often also included in the pricing terms for ammonia offtake from the plants.

10.3.3.4 Realised Gas Prices

In the case of ammonia indexed pricing, the average ammonia price is computed based on international industry publications: Fertecon, FMB and Green Markets. An FOB Caribbean reference is used in the majority of the contracts with the USG/Tampa quote being used in three customer contracts. The difference between the two prices is the freight cost, currently averaging US$42-44/tonne.

The basic structure of the formula is as follows:

$$P = Po + Af * (A - ARP)$$

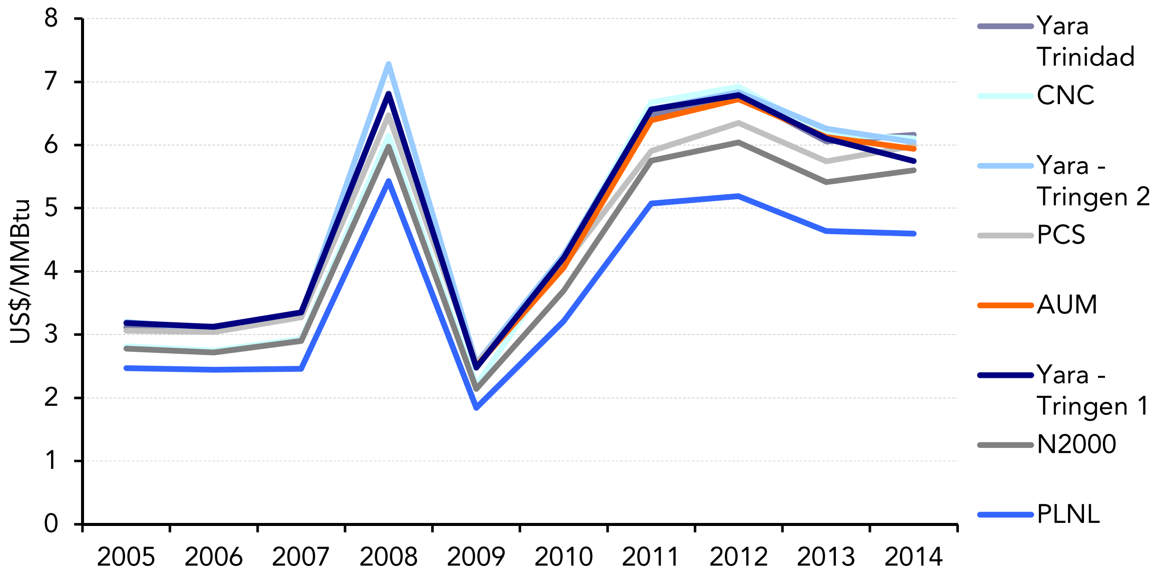
Where :-

- P Gas Price
- Po: Base Price
- Af: Adjustment Factor
- ARP: Ammonia Reference Price
- A: Actual Ammonia Price

NGC shares in the upside when the product price moves beyond the ARP reference price. The formula has evolved to provide higher rates of sharing at higher pricing bands.

The average annual gas prices paid by the ammonia producers are shown in the figure below.

Figure 10-23 Ammonia Production: Gas Prices Paid to NGC

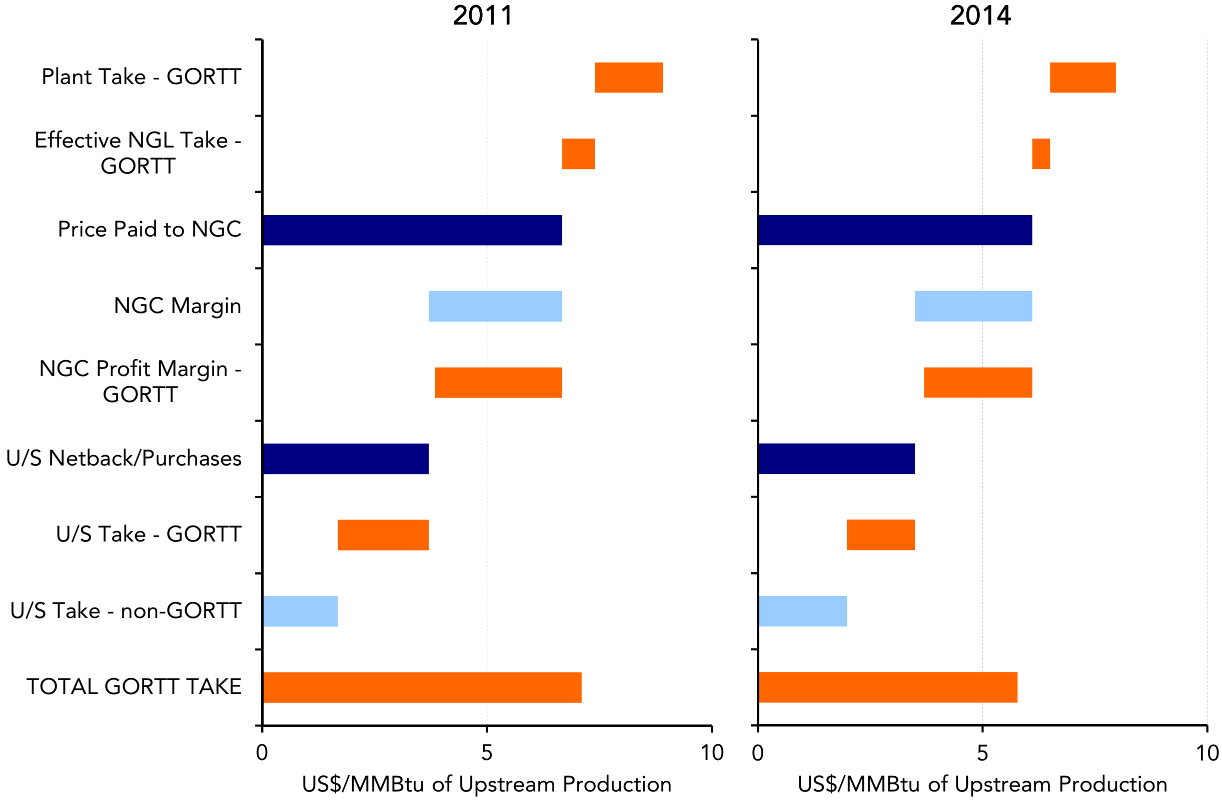


The ammonia plants buy gas from NGC on an ammonia price-linked basis and have benefitted from high ammonia prices over recent years. Poten has not been provided with details of the price mechanisms under which the individual ammonia producers purchase their gas from NGC, although, as per methanol, it is possible to derive close correlations to ammonia price movements from the data provided.

10.3.3.5 Revenue Waterfall / GORTT Take

Poten's assessment of the revenue waterfall for the CNC plant for both 2011 and 2014, taken as a representative example of the ammonia plants in general, is shown in the figure below.

Figure 10-24 CNC: Revenue Waterfall / GORTT Take



Overall GORTT take from the project was $5.78/MMBtu in 2014, consisting of:

- Plant take: $1.47/MMBtu
- Effective NGL take: $0.40/MMBtu
- NGC profit margin: $2.41/MMBtu
- Upstream take: $1.51/MMBtu

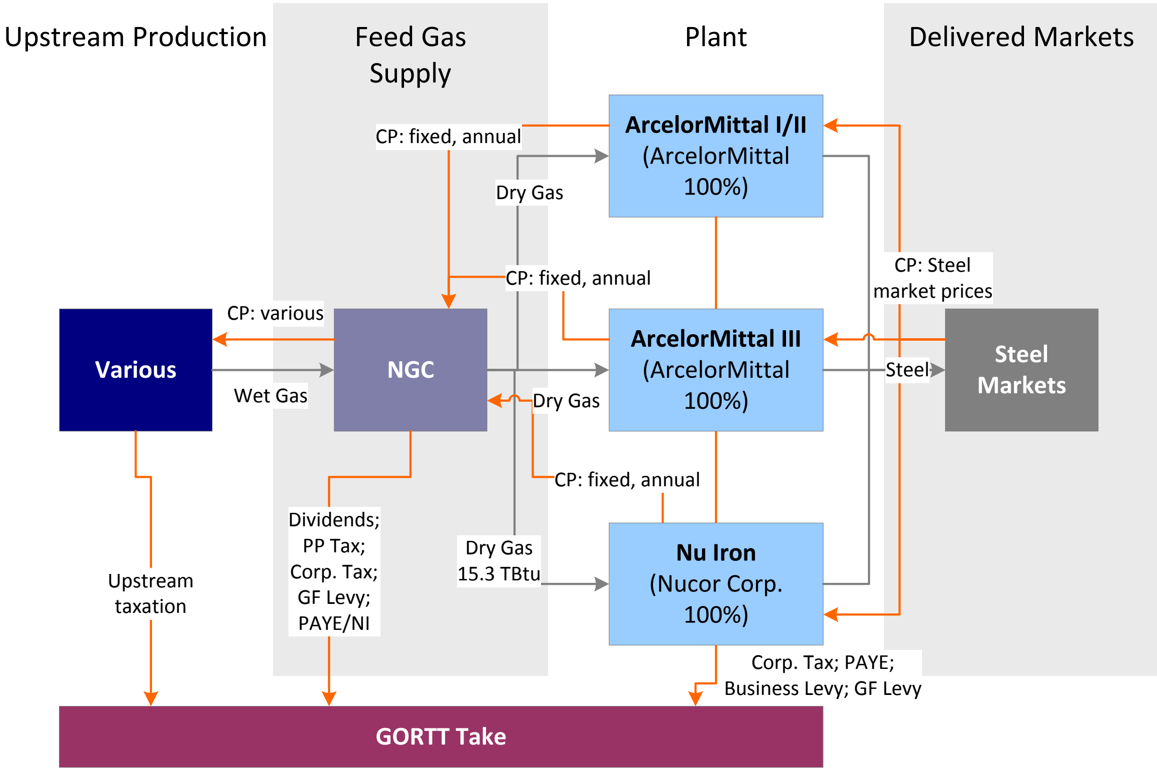
The higher overall GORTT take versus the Methanex Atlas example for methanol ($3.63/MMBtu) can be explained by a higher plant take (~$1/MMBtu) and NGC profit margin (~$1.4/MMBtu) in this case.

10.3.4 Steel

10.3.4.1 Project Structure

As shown in the figure overleaf, the steel plants operate under the same structure as the methanol and ammonia plants, with producers buying gas from the NGC portfolio.

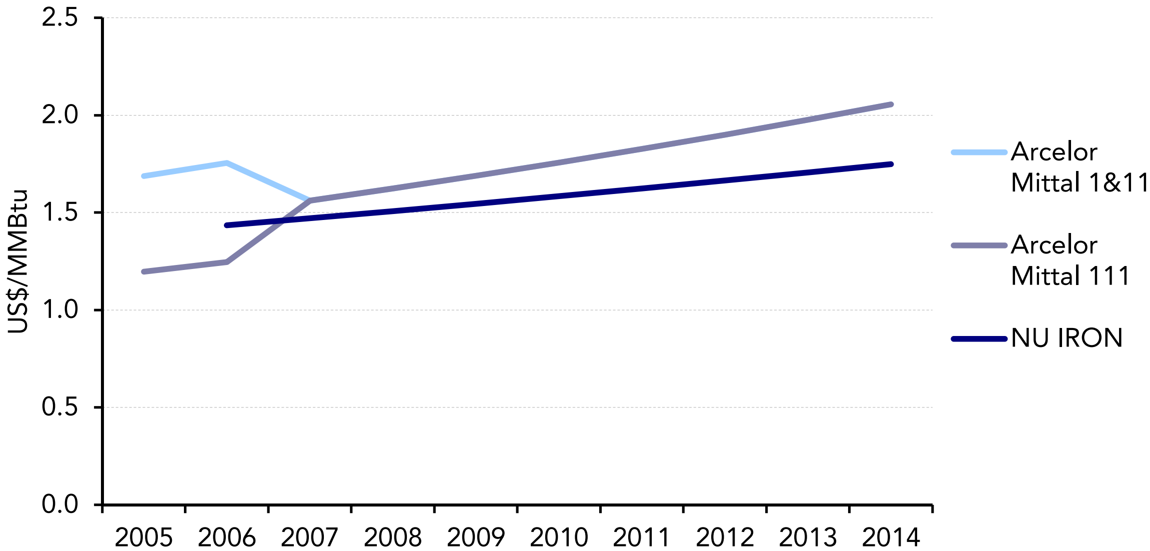
Figure 10-25 Steel Plants Physical / Financial Flows



10.3.4.2 Realised Gas Prices

As shown in the figure below, the steel plants buy gas from NGC at low prices which appear to be inflation indexed, although Poten has not been provided with the specific pricing formulae.

Figure 10-26 Iron & Steel Production: Gas Prices Paid to NGC



10.3.4.3 Revenue Waterfall / GORTT Take

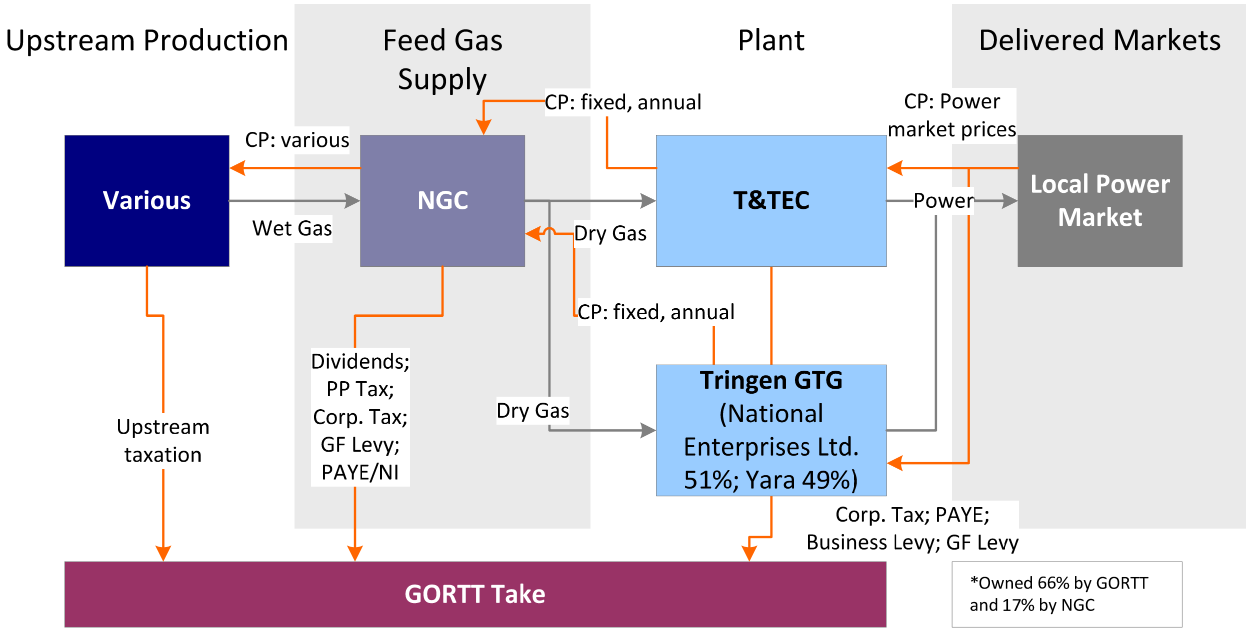
Poten's has not been provided with data on the steel industry to enable an assessment to be made of the tax paid by the plant or hence the overall GORTT take. However, our assessment is that the combined GORTT take from associated NGL, NGC profit margin and upstream take was $0.24/MMBtu in the case of Nu Iron and $0.54/MMBtu in the case of Arcelor Mittal.

10.3.5 Power Generation

10.3.5.1 Project Structure

As shown in Figure 10-27, T&TEC and Tringen GTG buy gas for power generation from the NGC portfolio.

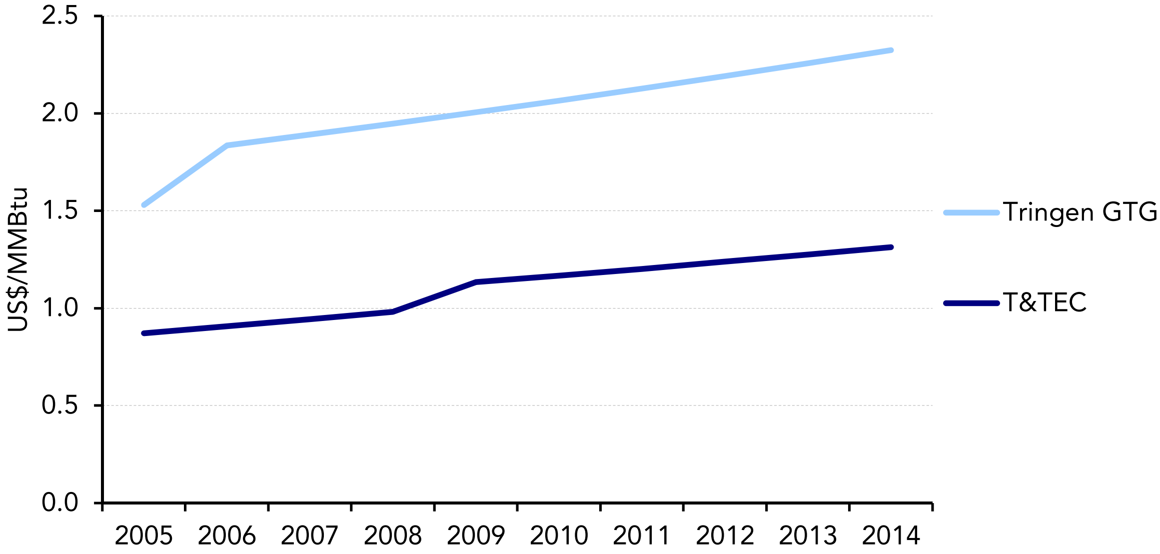
Figure 10-27 Power Generation Physical / Financial Flows



10.3.5.2 Realised Gas Prices

The Regulated Industries Commission (RIC) sets the price at which T&TEC sells power to different classes of consumer. In order to sustain T&TEC financially NGC sells it gas at a current price of around $1.35/MMBtu, with annual inflation escalation. (There is no contract in place between NGC and T&TEC at present. The original contract expired around 1995 and to date there has been no renewal. Discussions have taken place on several occasions over the years and there is a draft contract being reviewed. There are no specific terms and conditions relating volumes at present.) The gas prices paid by T&TEC (and also Tringen GTG) are shown in the figure overleaf.

Figure 10-28 Power Generation: Gas Prices Paid to NGC



The domestic price for gas in T&T is relatively low, indeed amongst the lowest in the world. Although domestic consumers benefit, this can be problematic as administratively set low domestic gas prices can result in inefficient use of energy and increased domestic gas demand from consumers. The large difference in price between domestic gas prices and the export netback price received from LNG or petrochemicals sales also creates a natural preference by gas suppliers to sell their gas to export projects rather than to the domestic market where this is possible. A low gas price also discourages upstream investment in exploring and developing new gas reserves. This issue is not as critical in T&T as it would be in larger countries as in T&T the domestic market (power generation , small Industry and cement manufacture) represents only 7.5% of the total volumes sold (11% if iron and steel production are included).

10.3.5.3 Revenue Waterfall / GORTT Take

Poten's has not been provided with data on the power generation industry to enable an assessment to be made of the tax paid by the plant or hence the overall GORTT take. However, our assessment is that the combined GORTT take from associated NGL, NGC profit margin and upstream take was minus $0.20/MMBtu in the case of T&TEC and $0.81/MMBtu in the case of Tringen GTG.

10.4 NETBACK PRICE & GORTT TAKE COMPARISON

10.4.1 Netback Prices

Drawing together the analysis for the individual industries described earlier in this section, Figure 10-29 and Figure 10-30 compare the effective netback price to the plant inlet across the various downstream industries from 2005 to 2014.

Figure 10-29 Netback Price Comparison at Plant Inlet by Plant

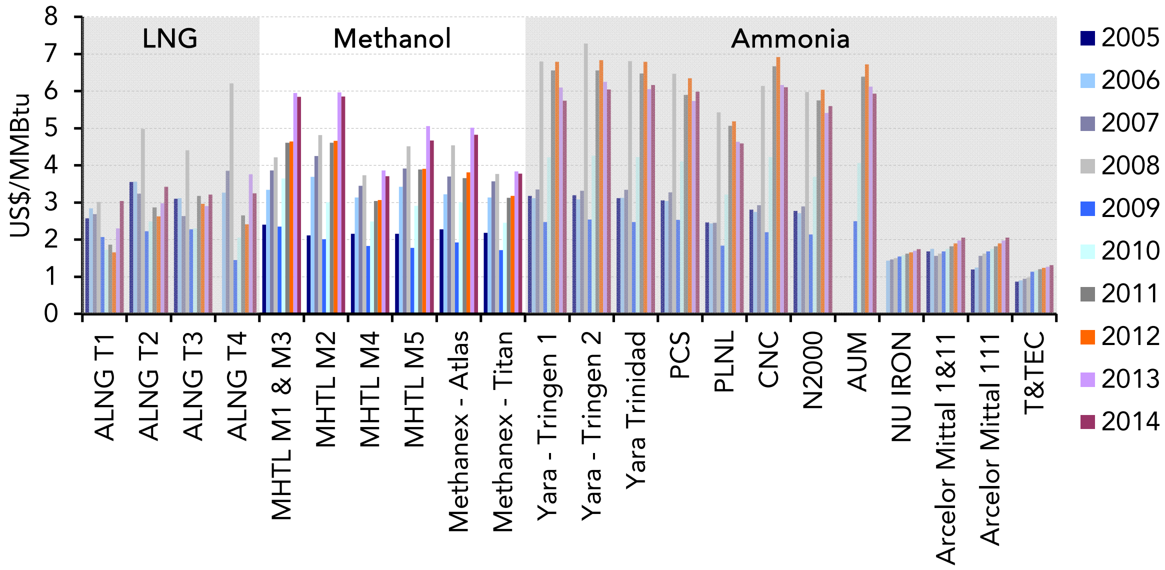
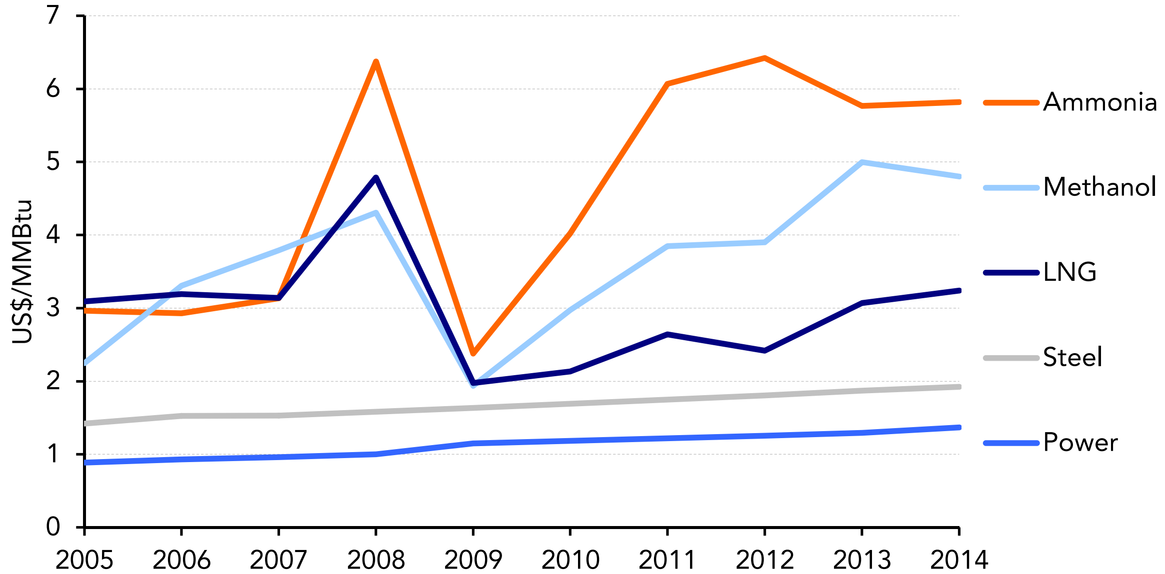


Figure 10-30 Netback Price Comparison at Plant Inlet by Sector



In order to achieve a fair comparison across all the industries the revenue at the plant inlet realised by the LNG plants for NGL sales has been reduced to match the price paid for gas by PPGPL to NGC. This is because NGC sells dry gas to the other industries rather than wet gas, with the NGL benefit from this dry gas being extracted by PPGPL. As per the LNG plants, if this NGL benefit was realised by the methanol / ammonia producers then their revenue would be higher.

Generally speaking, any assessment of gas monetisation options for world-scale gas resources would be expected to recommend LNG as the most attractive option for netback gas prices to the plant inlet, ahead of ammonia and methanol. Although a number of the ammonia plants in T&T have netted back over $7/MMBtu in recent years as a result of high ammonia prices, the relative attractiveness of LNG has been borne out over recent years for many projects across the globe, particularly in the Pacific Basin, which have been consistently realising LNG prices in excess of $15 MMBtu. Any plants constructed before the significant global construction cost rise over the latter part of the previous decade will have benefitted from low liquefaction costs and will likely have netted back prices to the plant inlet well in excess of $7/MMBtu.

Unfortunately for T&T, as detailed earlier in this section, the commercial and contractual structures of ALNG trains have been such that little of the benefit from high global LNG prices has flowed back to T&T. This is illustrated by the low netback prices that have been realised over recent years (weighted average of $2.42/MMBtu in 2012, $3.07/MMBtu in 2013 and $3.22/MMBtu in 2014). As well as ammonia, methanol has also outperformed LNG over recent years, with weighted average netback prices of $3.90/MMBtu in 2012, $5.00/MMBtu in 2013 and $4.80/MMBtu in 2014.

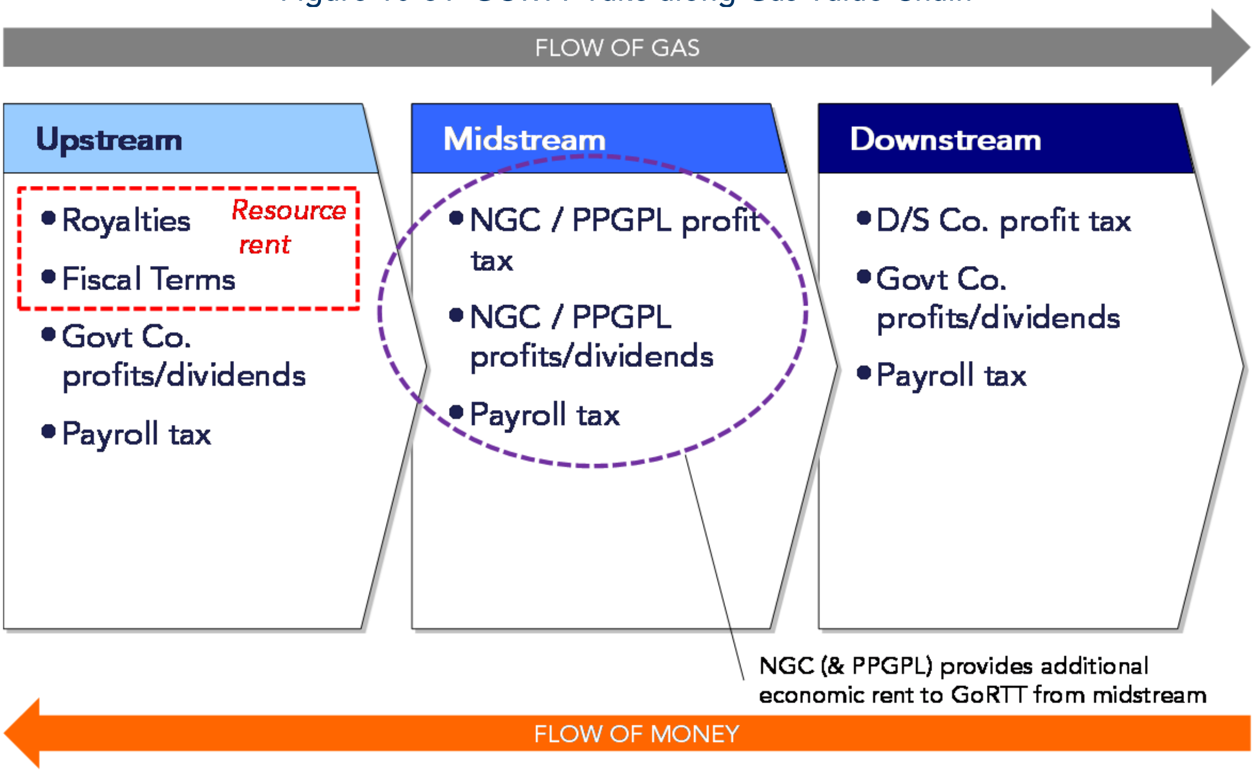
It is pertinent to note that even in 2008, a time of high HH prices and a high watermark for netback prices for ALNG, the weighted average netback price from LNG was $4.79/MMBtu, which was better than methanol ($4.31/MMBtu) but significantly worse than ammonia ($6.37/MMBtu).

With the exception of T&TEC which pays very low prices, the steel plants are consistently the lowest payers, buying gas from NGC at weighted average prices that have increased from $1.69/MMBtu in 2010 to $1.92/MMBtu in 2014.

10.4.2 GORTT Take

Although realised netback prices are a useful indicator of value flowing back to T&T from its gas-based industries, the key determinant of the “value” provided by the industry is the overall GORTT take from each of the gas value chains.

Figure 10-31 GORTT Take along Gas Value Chain



GORTT receives revenue from all three stages of gas value chain, as illustrated in Figure 10-31. Estimated overall GORTT take is shown in the figure below from 2008 to 2014. Insufficient data was provided to extend this analysis back to 2005 or to assess GORTT take from the iron & steel sector. The methodology utilised to undertake the analysis is described in Appendix I.

Figure 10-32 Overall GORTT Take Comparison by Plant

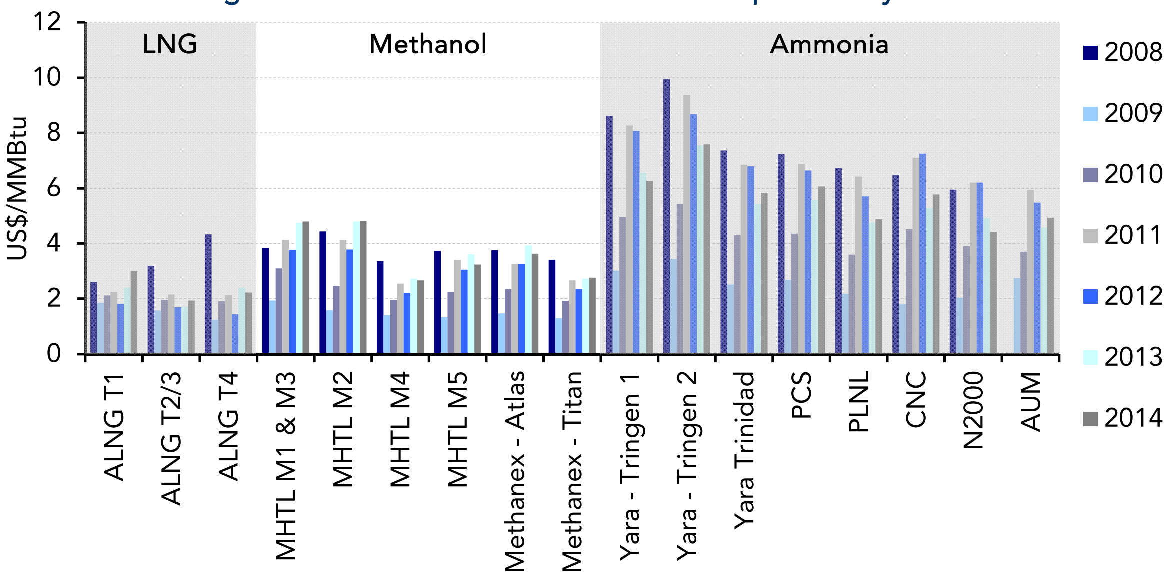
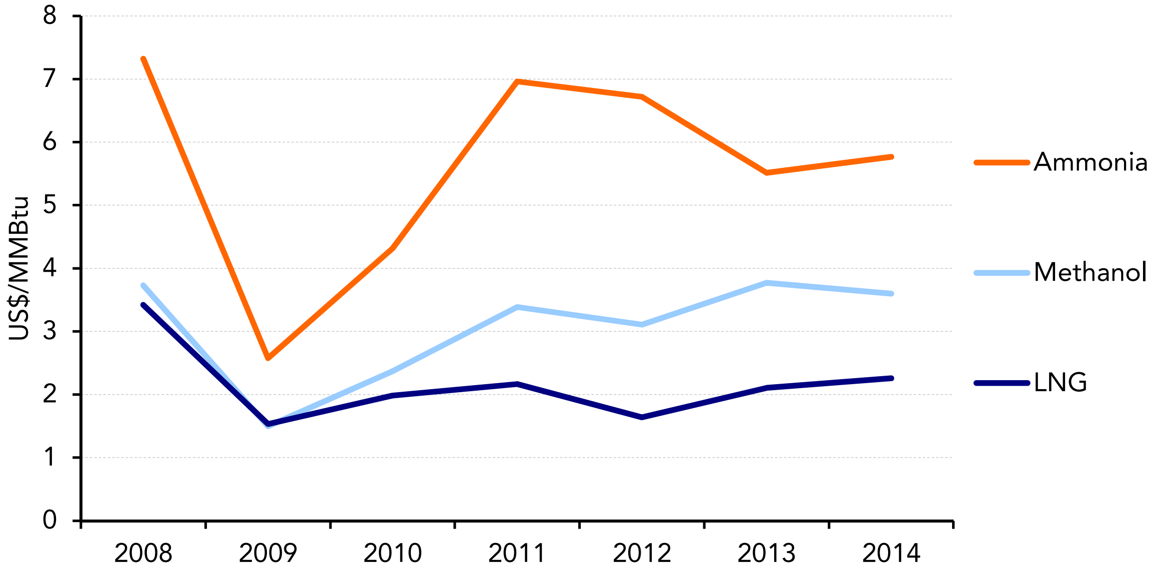


Figure 10-33 Overall GORTT Take Comparison by Sector



As would be anticipated, the results largely mirror those of the netback gas price analysis:

- Ammonia has provided the greatest value for T&T since 2008.
  - Estimated weighted average GORTT take from ammonia peaked at \$7.32/MMBtu in 2008 and then again at \$6.96/MMBtu in 2011 but declined to \$5.76/MMBtu in 2014. Within these figures there are significant variations between individual plants, e.g. in 2011 Yara's Tringen 2 provided an estimated \$9.37/MMBtu in 2011 versus \$6.21/MMBtu for N2000.
  - Some of the oldest ammonia plants are estimated to have provided some of the highest GORTT take of any of the downstream industries.

- GORTT take from methanol has trended between that from ammonia and LNG over recent years.
  - Estimated weighted average GORTT take from methanol has exceeded \$3/MMBtu each year from 2011. Again there are significant disparities between individual plants, e.g. in 2014 MHTL M1 & M3 provided an estimated \$4.80/MMBtu versus \$2.66/MMBtu for MHTL M4.

- LNG consumes >50% of T&T's gas production but has provided significantly lower value than either ammonia or methanol over recent years.
  - Estimated weighted average GORTT take from LNG peaked at \$3.42/MMBtu in 2008 (when it remained lower than methanol at \$3.73/MMBtu and substantially lower than ammonia at \$7.32/MMBtu) but has barely exceeded \$2/MMBtu in any year since then and was as low as \$1.64/MMBtu in 2012.

Again, the surprisingly poor return that GORTT has realised from LNG exports is a reflection of the particular commercial and contractual structures that govern ALNG, rather than a factor of the industry itself. Under different circumstances GORTT take from LNG would have been expected to be at least as high as ammonia over the last 5 years, at a time of historically high global LNG prices.

The analysis is further illustrated by the GORTT take breakdown provided by plant (Figure 10-34) and sector (Figure 10-35)

Figure 10-34 GORTT Take Breakdown for 2014 by Plant

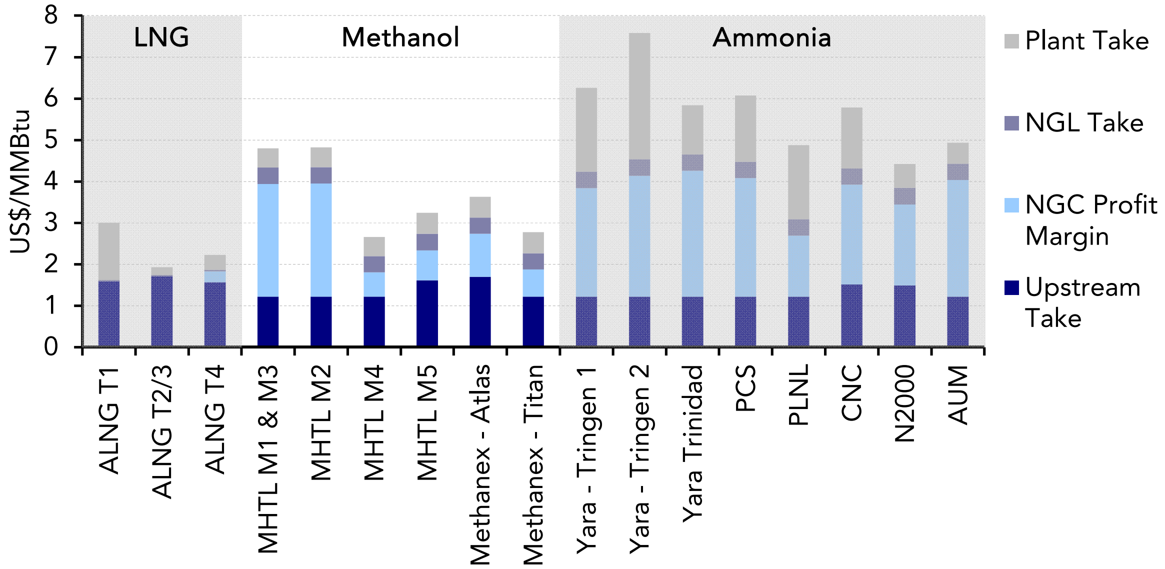
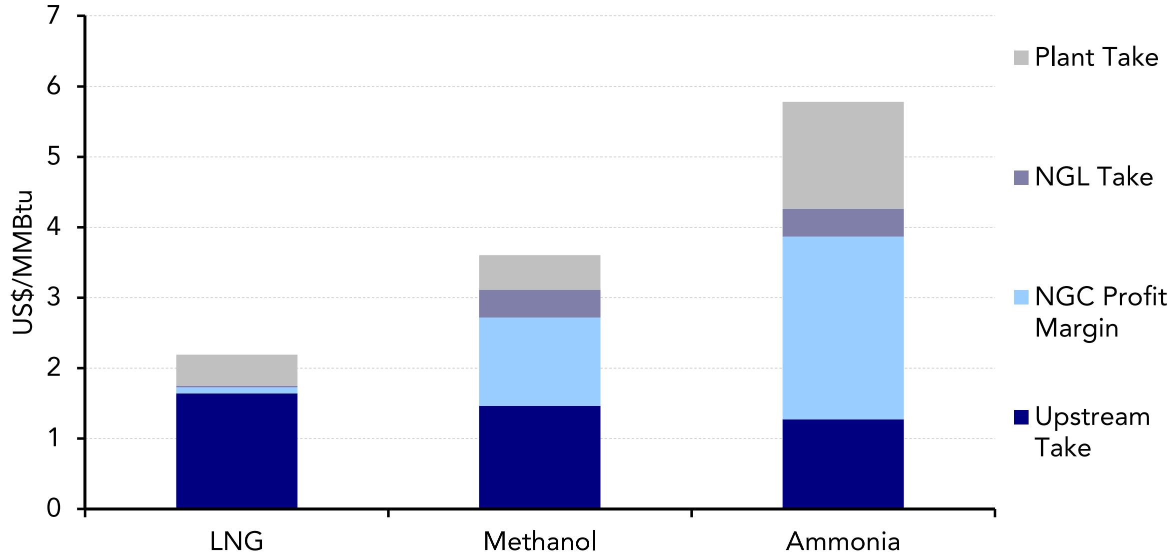


Figure 10-35 GORTT Take Breakdown for 2014 by Sector



Key points to note from the analysis are as follows:

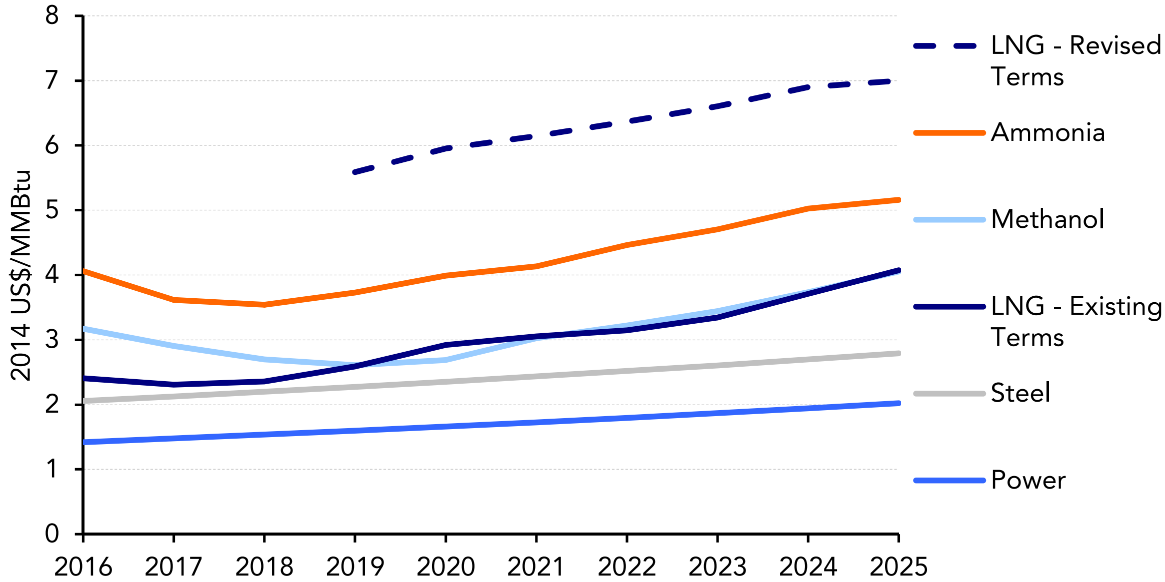
- The importance of NGC's estimated profit margin to the overall GORTT take from the methanol and ammonia value chains is clear; it averaged \$2.59/MMBtu for ammonia and \$1.25/MMBtu for methanol in 2014.
- GORTT has substantially benefitted from its stakes in the Tringen 1 & 2 ammonia plants, to the tune of over \$1/MMBtu in 2013 and 2014.

- NGC's profit margin varied significantly between different plants in the same sector in 2014, e.g. MHTL M4: $0.58/MMBtu and MHTL M2: $2.72/MMBtu. The data provided suggests that NGC has been able to capture higher prices from downstream industries when existing supply contracts have expired.
- Average prices paid to upstream by LNG were somewhat higher than the average price paid by NGC to upstream, hence GORTT upstream take from LNG ($1.64/MMBtu) was higher than from methanol ($1.46/MMBtu) or ammonia ($1.27/MMBtu) in 2014.
- GORTT take was significantly higher from ALNG Train 1 ($3.10/MMBtu) than Trains 2/3 ($1.93/MMBtu) or Train 4 ($2.22/MMBtu) in 2014, due to a far higher plant take (taxation plus revenue from the NGC/NEL stake).
- Estimated GORTT NGL take from the non-LNG sectors, which was derived from PPGPL's activities, was $0.40/MMBtu in 2014.
- Other than from the upstream, GORTT take from the ALNG Train 2/3 ($0.22/MMBtu) and Train 4 ($0.40/MMBtu) value chains was very modest.

10.5 NETBACK GAS PRICE PROJECTIONS

Based on the future price projections described in Section 9.2 and the historical netback price analysis described earlier in this section, an estimate has been of the future netback prices that are projected to be realised from the various downstream sectors, as shown in the figure below.

Figure 10-36 Projected Gas Netback Price as Plant Inlet Comparison



The analysis assumes that:

- For "LNG – revised terms", i.e. post-expiry of the existing contracts:
  - Base price of UK NBP minus freight, plus an assumed \$1/MMBtu margin over the base price to account for trading profits.
  - The train's only remuneration will be a fixed fee of \$1/MMBtu, with the remaining revenue flowing back to plant inlet.
- Ammonia plants will match the gas pricing paid by the highest-paying ammonia plant after their current supply contract expires, with the same applying for methanol.
- Steel and power prices will continue to increase modestly as per current arrangements.

Under the existing arrangements, ammonia is projected to continue to provide the most attractive netback prices, although as a result of our projected decline in ammonia prices these netbacks are projected to decline to ~\$3.5/MMBtu by 2018 before increasing to ~\$4.0/MMBtu by 2020 and \$5.2/MMBtu by 2025. Netback prices from existing LNG arrangements are projected to remain relatively low, rising from ~\$2.3/MMBtu in 2017 to ~\$2.9/MMBtu by 2019 and \$4.1/MMBtu by 2025. Following projected methanol price declines, netback prices from methanol are projected to trend down to similar levels to those from the existing LNG arrangements by 2019.

It is clear from the analysis that a significantly opportunity exists for T&T to increase the netback gas prices that are received from LNG after the existing agreements expire. Our projected netback price under revised LNG arrangements is ~\$5.6/MMBtu in 2019, which is when the existing Train 1 contracts will expire, rising to ~\$7.0/MMBtu by 2025. This would make LNG clearly the most attractive of T&T's

existing infrastructure for gas monetisation under our projections, which is typically what would be expected from such an analysis. The options for GORTT following the expiry of the existing LNG contracts are discussed in Section 12.

Section 11 Downstream: Gas Supply & Demand Situation

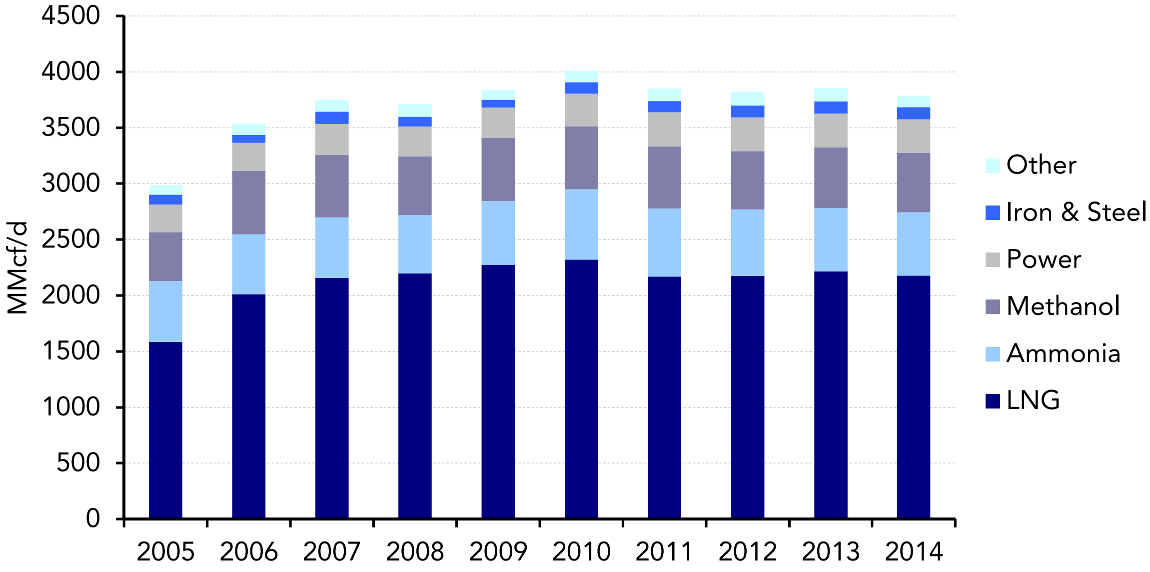
11.1 CURRENT SUPPLY / DEMAND SITUATION

11.1.1 Overview

As shown in the figure below, overall gas supply to downstream industries has declined somewhat since peaking in 2010. As discussed in Section 5, one issue that has curtailed supply is that certain upstream supply projects have been offline on protracted maintenance. In addition, reduced exploration activity through the mid-2000s has fed through to insufficient upstream deliverability now; fiscal terms at the time were deemed relatively unattractive for exploration.

Figure 11-1 Historical Gas Supply to Downstream Consumption Sectors

(source: MEEA)



Supply declines from peak to 2014 for the various consumption sectors are shown in the table below.

Table 11-1 Gas Supply to Downstream Consumption Sectors

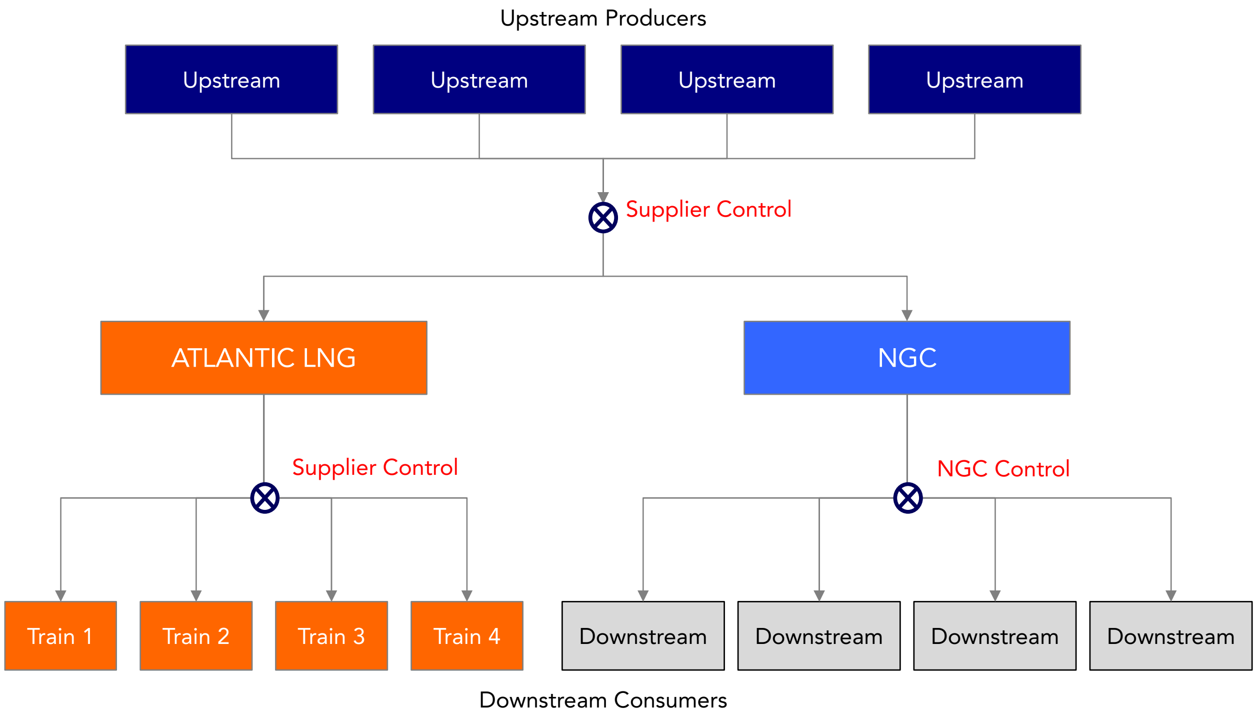
(Source: MEEA)

Sector	Peak Supply Year	Peak Supply (Annual Av.) MMcf/d	2014 Supply MMcf/d	Decline from Peak
LNG	2010	2,321	2,178	6.1%
Ammonia	2010	630	566	10.1%
Methanol	2009	568	532	6.3%
Power	2011-3	304	301	1.1%
Iron & Steel	2007	112	106	5.3%
Other	2012	123	104	15.4%
TOTAL	2010	4,010	3,787	5.6%

It is clear that all export-based industries have seen gas supply availability declines over recent years.

As shown in the figure below, gas supply is managed at 3 virtual points in the system.

Figure 11-2 Management of Gas Supply to Downstream



The contractual structures for gas supply to NGC were developed during a time of gas surfeit when flexibility in volume offtake was required to stimulate downstream industry. Since then the situation has changed to one of shortfall. We understand that while there are obligations in NGC's upstream contracts on the producers to meet supply commitments, in many cases there are no specific penalties for failing to do so. This means that it is largely in the control of the upstream suppliers to allocate gas supply between their contracts to supply ALNG and their contracts to supply NGC. As discussed in Section 5, a key issue is that although all major downstream industries have experienced declining gas supply availability, overall gas supply to LNG has been largely maintained at contractual levels while overall gas supply to NGC has not. This in turn has left NGC short of gas to supply its downstream customers, as is discussed later in this section.

11.1.2 LNG

Gas supply to each of the four trains at ALNG is shown from Figure 11-3 to Figure 11-6. It is clear from the analysis that supply declines have not been distributed evenly across the four trains. In particular, supply to Train 1 declined from 548 MMcf/d in 2010 to 469 MMcf/d in 2014, a reduction of ~14%, while supply to Train 4 declined from a peak of 743 MMcf/d in 2013 to 723 MMcf/d in 2014, a reduction of ~3% (and a reduction of only ~1% from 2010 supply of 730 MMcf/d). Supply to Trains 2 and 3 both peaked in 2010 at 547 MMcf/d and 528 MMcf/d respectively and in 2014 was 502 MMcf/d and 512 MMcf/d respectively, representing a decline from peak for Train 2 of ~8% and for Train 3 of ~3%.

Figure 11-3 Historical Gas Supply to ALNG Train 1
(source: ALNG)

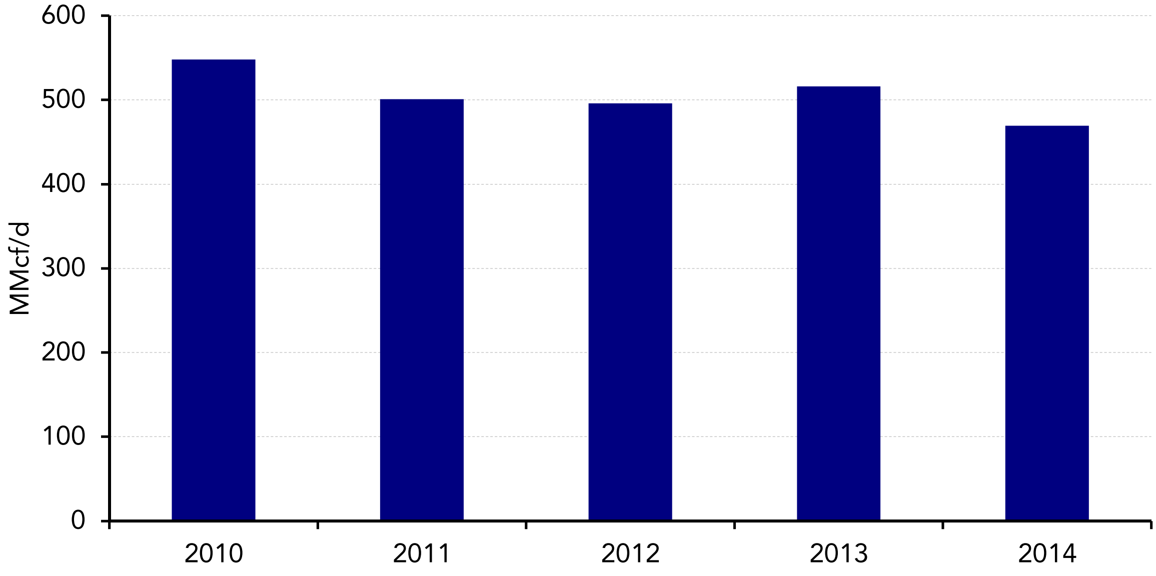


Figure 11-4 Historical Gas Supply to ALNG Train 2
(source: ALNG)

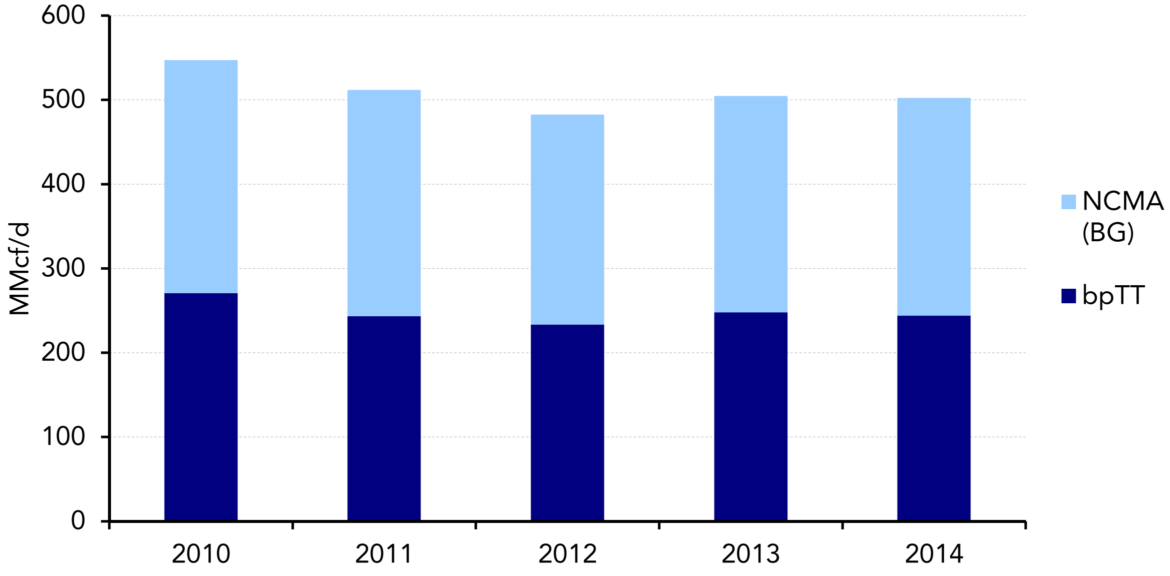


Figure 11-5 Historical Gas Supply to ALNG Train 3
(source: ALNG)

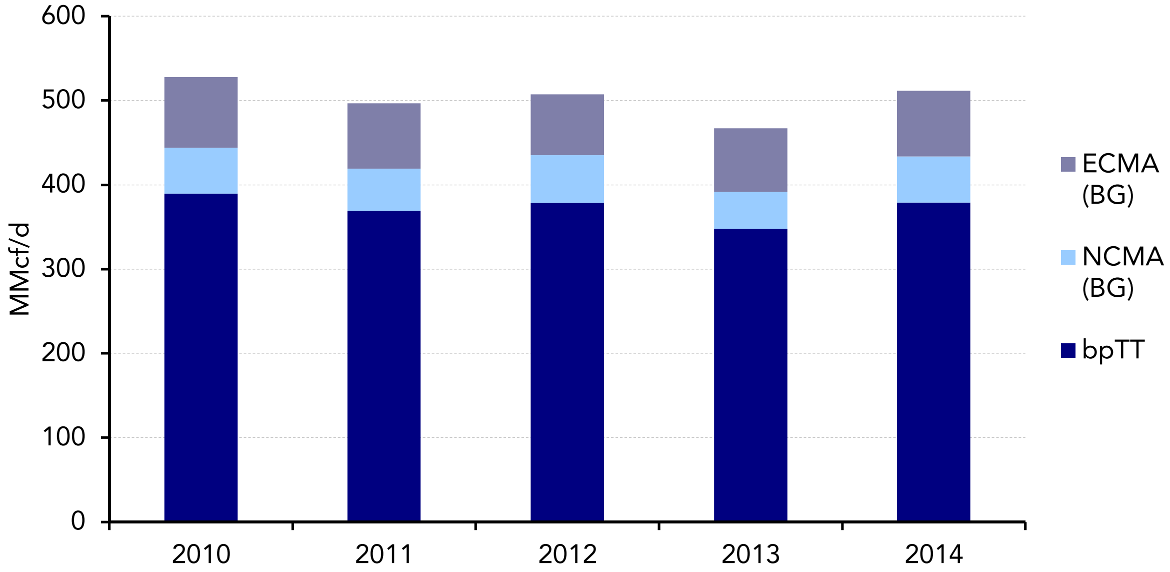
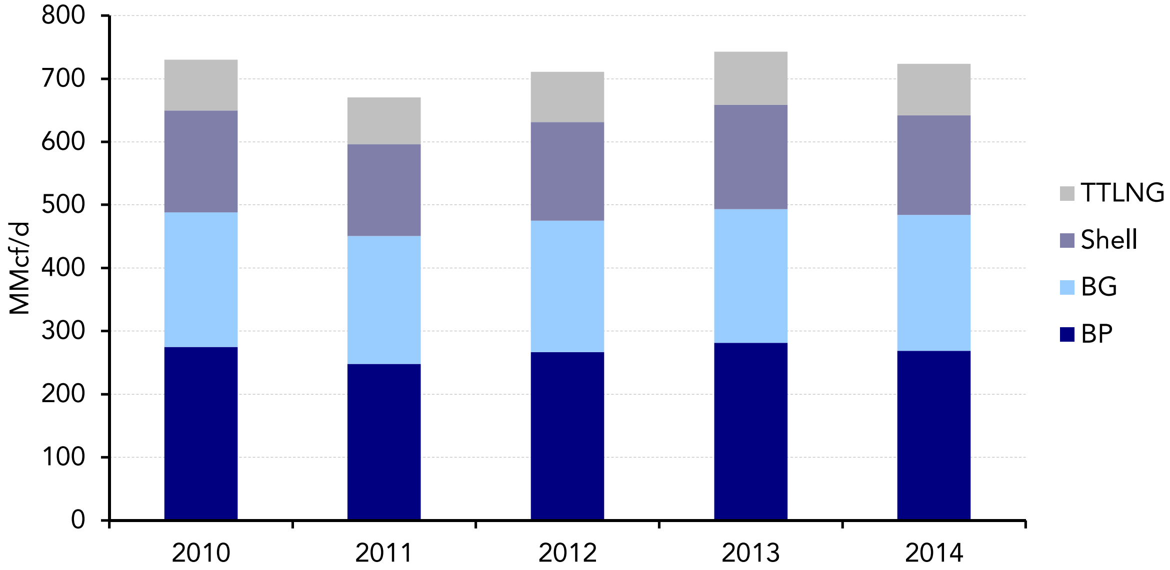


Figure 11-6 Historical Gas Supply to ALNG Train 4
(source: ALNG)



Both bpTT and BG appear to have prioritised supply to Train 4 over the other trains. bpTT is the sole supplier to Train 1 where supply has declined ~14% since 2010. Over the same period bpTT's supply to Train 2 declined by ~10%, its supply to Train 3 declined by ~3% and its supply to Train 4 declined by ~2%.

For bpTT in particular it is unsurprising that supply to Train 4 would be prioritised, where it controls its own LNG offtake and can extract value through its trading operations (as is discussed in Section 10). bpTT's reduction of supply to Train 1 can also be explained by Train 1 having consistently realised lower gas prices to upstream for it than Trains 2 and 3, as discussed in Section 5.

11.1.3 NGC

11.1.3.1 Gas Supply & Demand

NGC takes on the responsibility as the central aggregator and wholesaler of gas between the upstream and downstream within the gas sector, with the exception of LNG, contracting for gas with upstream suppliers and onselling the gas to downstream consumers. This role is not enshrined in legislation or regulation but has evolved through NGC's historical role of transporting gas and selling gas to the power sector.

As shown in Figure 11-8, NCG appears to be in a comfortable position in terms of contracted gas supply, although there are some downstream contracts from 2019 onwards for which it does not presently have contracted upstream gas supply. However, as discussed in Section 5 and shown in the figure below, actual supply to NGC from upstream has been well below contracted supply which is currently ~2.1 Bcf/d, versus 2014 supply of ~1.6 Bcf/d.

Figure 11-7 Estimated Historical Annual Average Gas Supply to NGC
(source: MEEA, NGC)

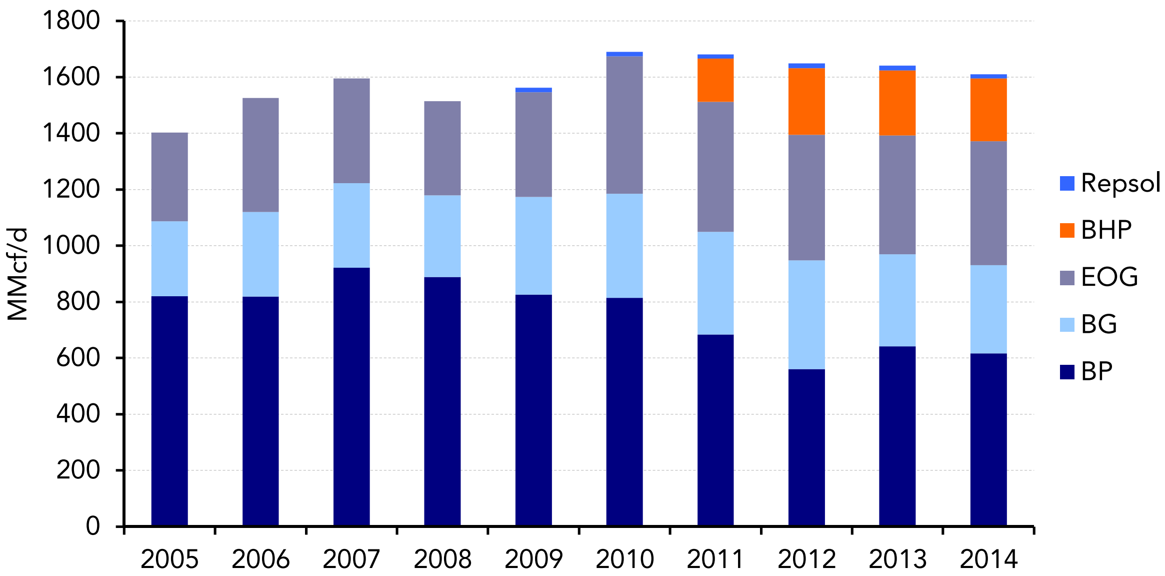
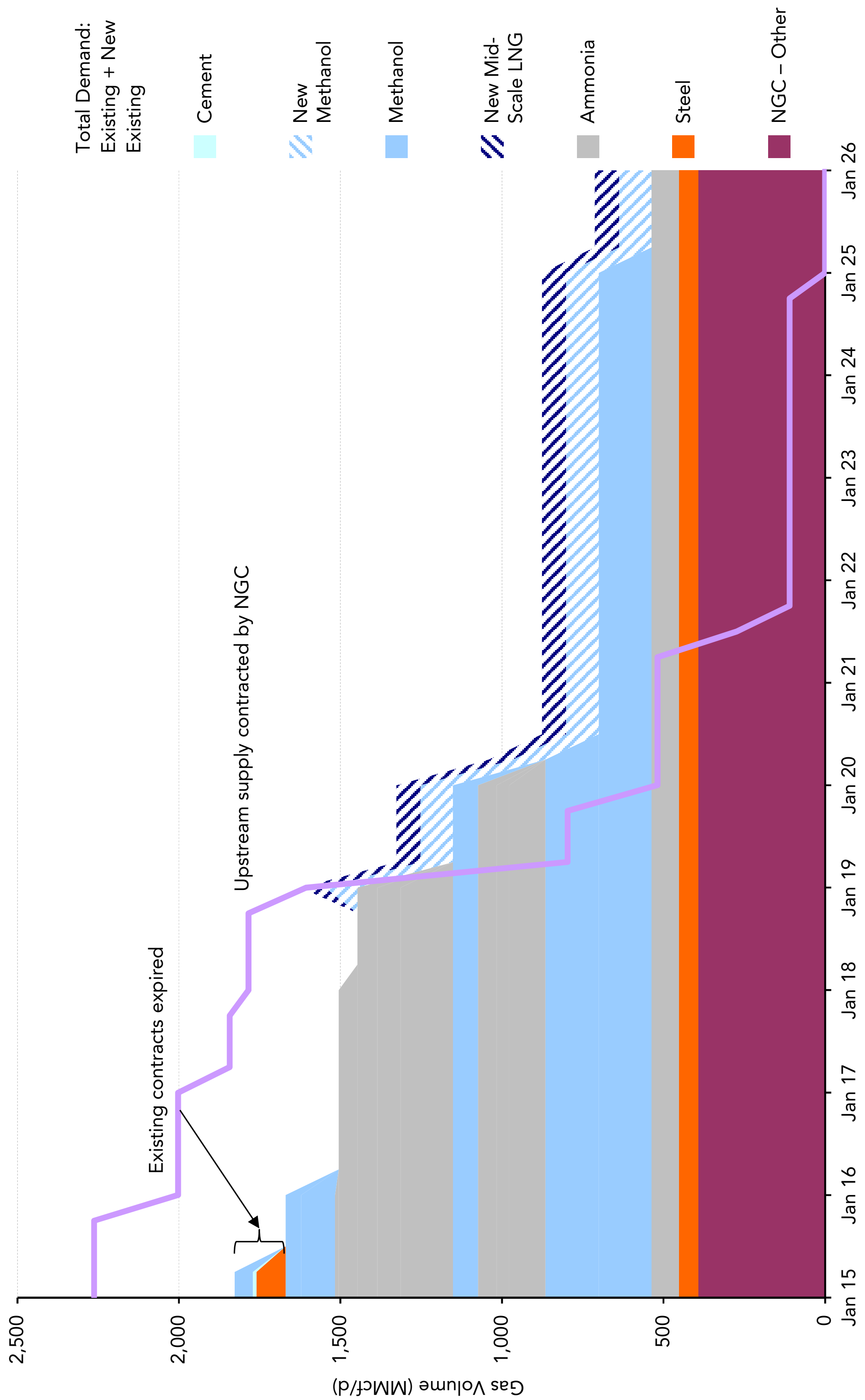


Figure 11-8 NGC Contracted Gas Demand vs. Projected Supply

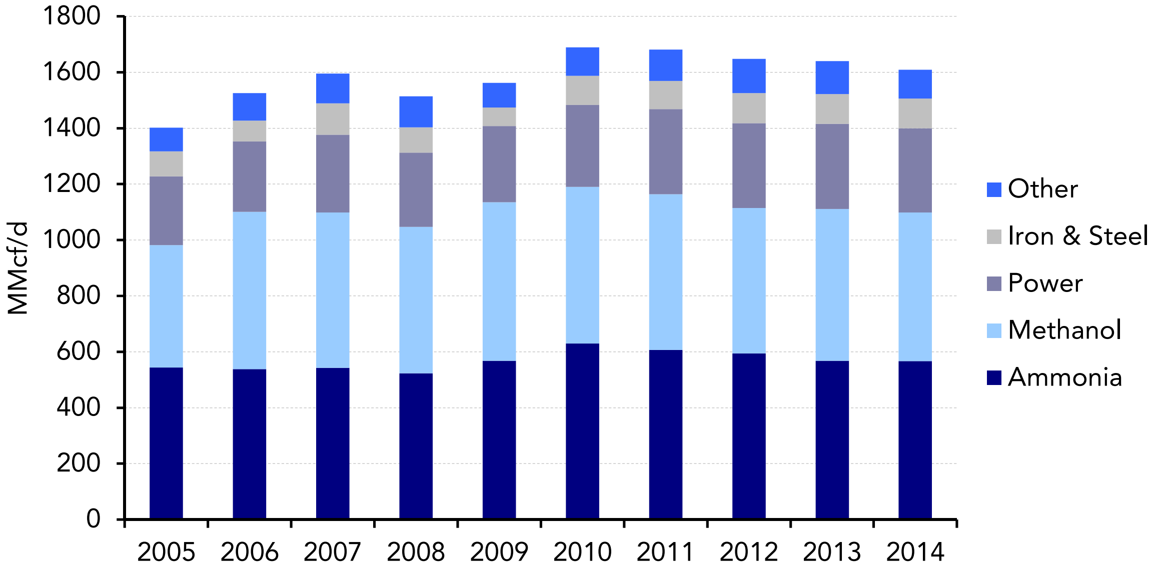
(source: MEEA, NGC)



As a result, NGC has struggled of late to meet its downstream gas supply commitments and has been forced to cut supply to certain downstream buyers. As shown in the figure below, NGC's total supply to downstream industries was around 1.6 Bcf/d, versus contractual commitments of around 1.8 Bcf/d, as per Figure 11-8. As shown in Table 11-1, NGC supply cuts have been primarily to the ammonia, methanol and steel industries, with supply to the power sector protected.

Figure 11-9 Historical Gas Supply to Downstream Consumption Sectors (non-LNG)

(source: MEEA)

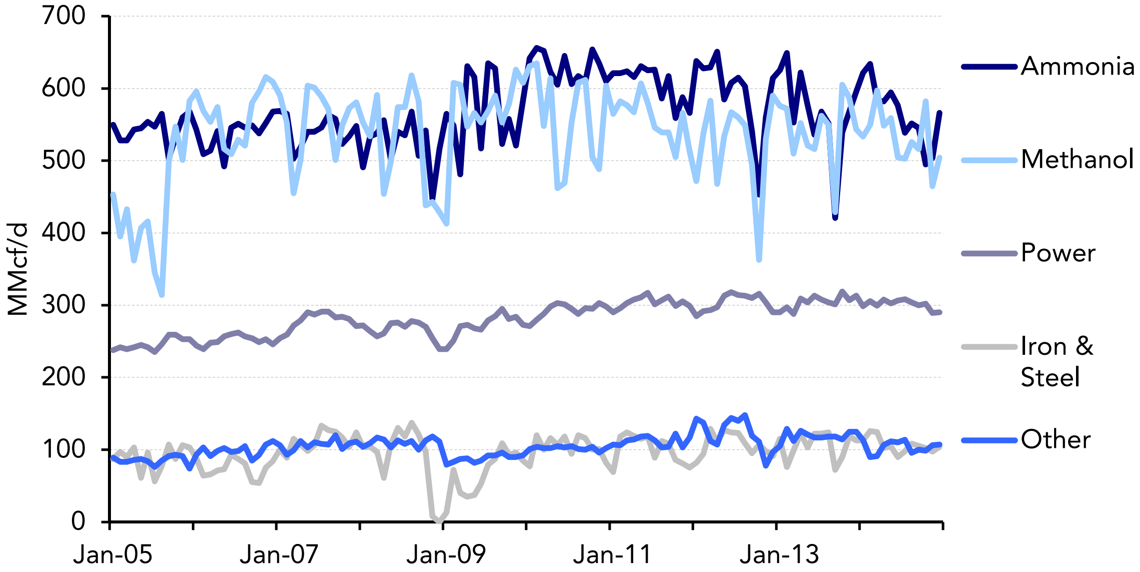


The problem has its roots in the past, when gas was in surfeit, and there was considerable uncertainty as to when new downstream projects would come onstream. The initial NGC contracting for gas supply was undertaken at a time when the suppliers had developed resources but the downstream consumers and plants were still under development and, in some cases, were late in being commissioned or in some cases not completed at all. Due to this high demand uncertainty, NGC negotiated flexible terms in the volume supply levels from upstream to allow the company to avoid exposure to onerous ToP commitments. These arrangements worked well in an oversupply situation allowing NGC to manage its supply of gas in line with demand. However, the flexible volume commitment was made available to both buyer and seller.

As the supply situation has tightened over the last few years, with all of the downstream plants operational, these arrangements have left NGC vulnerable to under-delivery, without the ability to impose delivery to a level that will match the downstream commitment, or gain compensation. Unlike in its upstream supply contracts, our understanding is that NGC has limited flexibility in its downstream supply contracts.

In addition to the long-term supply deficit, the short-term variability of supply to NGC from upstream discussed in Section 5 has left NGC in the difficult position of managing this variability with its downstream customers. Monthly supply levels to downstream consumers are shown in Figure 11-10.

Figure 11-10 Historical Gas Supply from NGC to Downstream Consumers
(source: MEEA)



Contractually NGC has handled this under delivery/mismatch situation by declaring force majeure (FM) or partial FM on the downstream buyers, thus relieving it of performance obligations. Downstream companies report that FM has been declared as often as 3 times in a week on certain occasions.

A significant activity for NGC in its aggregation role in the gas short situation over the last few years has been the allocation of gas – deciding how supply to each offtaker (with the exception of power and small industries which are protected) will be reduced in the face of a supply shortfall. NGC does not have any set rules or allocation policy for reducing supply to certain industries, rather it largely reduces gas supply to all consumers except power and small consumers on a pro rata basis.

Cutting on a pro rata basis would normally be considered to be a fair approach, as all downstream suppliers will take a proportionate cut, but in practice the cuts are not entirely pro rata. The reason is that different plants have different abilities to turn down; all process plants have limitations to which they can have their gas supply reduced and still operate. Hence, a percentage reduction in gas supply will not affect all plants equally as some may be able to continue to operate while others would have to shut down. As such, we understand that NGC has managed the cuts to different downstream buyers in order to enable them to continue to operate, with the exception of FM cuts, i.e. at times consumers with less operational flexibility have had their gas supply cut less than consumers with higher operational flexibility.

The inability to supply gas at contract volumes to the petrochemical plants has serious consequences. The revenues are curtailed and the project may not be able to meet sales commitments which may require them the go into the international market for replacement supplies. Another critical impact is the deleterious impact on plant equipment due to cycling to match production with gas supply. The refractory elements of the plants are subject to much higher rates of degradation when the plants are cycled, resulting in higher maintenance costs and future downtime.

Clearly NGC's reliance on FM to handle downstream curtailment is not a typical use of FM and it would clearly be preferable if there were alternative, more transparent mechanisms to deal with shortfall situations. In Poten's view NGC should consider including in its downstream GSAs provisions to enable

NGC to make a downward adjustment in Annual Contract Quantity in the event of scheduled upstream maintenance impacting its upstream supply volumes. As discussed in Section 5, NGC should also ensure that its upstream gas supply contracts have enforceable provisions to ensure that volumes supplied are in line with expectations.

For future downstream contracts NGC could also consider differentiation in the status of customers as either firm or interruptible depending on the price paid to ensure supply. This is a standard approach taken in the gas industry to manage supply and demand. However, the bulk of gas demand in T&T comes from industries requiring baseload supply which have no ability to switch feedstock. As such this approach is likely to only have limited applicability in T&T, although downstream consumers may be prepared to consider a portion of interruptible supply provided a base level required to operate their plant is a firm commitment.

NGC has acted to ameliorate future interruptions by aligning planned shutdowns in upstream and downstream operations so that reduced supply is offset, as best as possible, by a reduced demand. This is a more positive approach rather than claiming Force Majeure which has the potential to further polarise the sector due to the history of abuse where commercial parties seek to avoid liability for non-performance of their respective obligations under gas supply agreements. Closer coordination between all participants is also needed to reduce the impact of planned upstream supply shut-ins as well as agreed procedures for curtailments when temporary shortages occur. Dialogue with industry is required to determine the best methods for addressing both features.

11.2 FUTURE SUPPLY / DEMAND SITUATION

Based on the potential future gas supply profiles detailed in Section 7 and the downstream gas supply contractual commitments and demand detailed in Section 9 and in this section, T&T's projected future gas supply and demand balance is shown in Figure 11-11. It should be noted that an assumed shrinkage of 3.5% has been applied to the gross figures provided in Section 7 to give an expected sales gas figure. This shrinkage has been observed in MEEA data for 2014.

T&T has a current downstream portfolio that could consume an estimated ~4.3 Bcf/d. This demand is not being fully met and in Poten's view it is not realistic to expect that it will be met in future on a long-term basis (under the most optimistic supply forecast demand could be fully for a period of ~3 years from 2019).

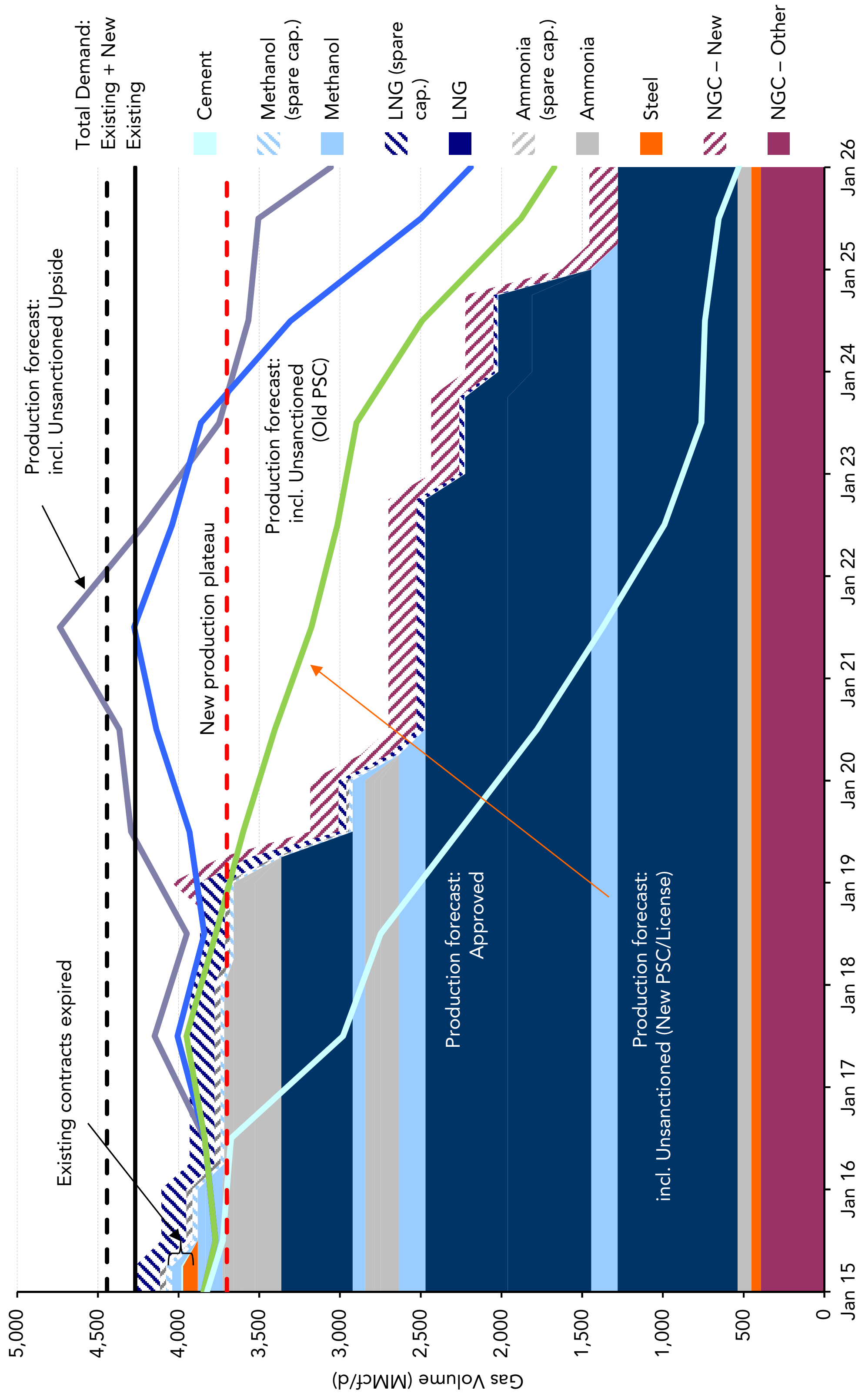
Considering only approved upstream gas supply projects, gas supply will fall rapidly from 2016-17 and supply will be some way short of meeting existing downstream contractual commitments, i.e. the current shortfall situation will deteriorate further, let alone providing gas to enable the extension of expiring contracts. Adding in production from unsanctioned developments under new PSC/license terms would provide sufficient gas to meet downstream contractual commitments, but not to meet demand. It would also only provide limited volumes/durations for expiring downstream contracts to be extended from 2019. Extending expiring downstream contracts well into the 2020s will require substantial unsanctioned production under the more economically-challenged old PSC terms.

As discussed in Section 7, Poten's view is that gas supply rates of ~1.4 Tcf/y are likely to persist in the coming years and are a realistic expectation of future supply. This equates to a sales gas figure of ~3.7 Bcf/d that is shown as the "new production plateau" in Figure 11-11. At this level supply will be insufficient to meet downstream contractual commitments until contracted volumes drop to ~3.7 Bcf/d from 2016, and there will be no excess supply over contracted downstream sales until contracted volumes drop to ~2.9 Bcf/d from 2019 with the expiry of the contracts to supply ALNG Train 1 and almost all of T&T's ammonia capacity. Under such a scenario for the next several years at least there is not going to be any surplus gas available to justify the extension by NGC of any of its downstream contracts that have already expired or those that expire before 2018. Further extension of any downstream contracts by NGC will only extend the existing contractual shortfall situation.

It is also clear that the sanctioning of any gas supply to new downstream ventures will come at the expense of supply to existing operating assets, i.e. if a new plant is developed then it is likely that an old plant will have to be shut down. The 175 MMcf/d that is planned to be supplied to the new mid-scale LNG and methanol plants is shown in Figure 11-11 as "NGC – New". The evaluation of new gas-based industries is discussed in Section 13. Given the large capital cost of new plants it will likely be more economically effective for T&T to continue to utilise its existing plants.

While gas supply is likely to available from 2019 to extend supply contracts to existing downstream industries, it is highly likely that gas supply will be insufficient to fully meet demand and as such decisions will have to be taken over which contracts to extend and which downstream industries to shut down. In the absence of large volumes of incremental supply, directionally the gas sector will need to focus on arrangements to achieve higher gas prices and greater efficiency in the existing plant and production facilities, i.e. a focus on developing value rather than growth. This is discussed further in Section 12.

Figure 11-11 Contracted Gas Demand vs. Projected Supply Scenarios



12.1 INTRODUCTION

The analysis detailed in Section 11 indicates that the full gas demand of the existing downstream portfolio of ~4.3 Bcf/d is not being fully met and in Poten's view it is not realistic to expect that it will be met in future on a long-term basis. Suupply is expected to be insufficient to meet downstream contractual commitments until contracted volumes drop to ~3.7 Bcf/d from 2016, and there will be no excess supply over contracted downstream sales until contracted volumes drop to ~2.9 Bcf/d from 2019. Under such a scenario for the next several years at least there is not going to be any surplus gas available to justify the extension by NGC of any of its downstream contracts that have already expired or those that expire before 2018. Further extension of any downstream contracts by NGC will only extend the existing contractual shortfall situation.

Sanctioning of any gas supply to new downstream ventures will come at the expense of supply to existing operating assets, i.e. if a new plant is developed then it is likely that an old plant will have to be shut down. Given the large capital cost of new plants it will likely be more economically effective for T&T to continue to utilise its existing plants.

While gas supply is likely to available from 2019 to extend supply contracts to existing downstream industries, it is highly likely that gas supply will be insufficient to fully meet demand and as such decisions will have to be taken over which contracts to extend and which downstream industries to shut down. In the absence of large volumes of incremental supply, directionally the gas sector will need to focus on arrangements to achieve higher gas prices and greater efficiency in the existing plant and production facilities, i.e. a focus on developing value rather than growth. Products from derivatives remain an option, as discussed in Section 13.

It is also clear from the analysis in Section 10 that the commercial arrangements of various aspects of the mid and downstream sector have not effectively maximised the potential return to GORTT from the gas sector over recent years, particularly from LNG. Under these circumstances it is appropriate to consider whether the existing structures of the mid and downstream areas of the gas sector are optimal from a GORTT perspective and to identify potential areas for improvement.

12.2 PRIORITISATION / ALLOCATION OF GAS

In an ideal world the development and management of a portfolio for T&T natural gas resource utilisation would be based upon a number of parameters:

- GORTT take per unit of gas produced.
- Employment generated.
- Development of the local skill base.
- Reduction of exposure to volatility of specific markets.

Some industries may add more value but employ fewer people, while other options may result in a lot of jobs and broaden the local skills base but provide lower value for the natural resource. The purpose of developing a portfolio is to gain a balance across the range of parameters, and ensure that there is not undue exposure to one particular market.

Poten has undertaken an assessment of the historical GORTT take from the various gas value chains (see Section 10). We have insufficient data available to undertake an assessment of future GORTT take from the various value chains. However, the netback price projections described in Section 10.5 can be taken as a reasonable proxy for the expected relative attractiveness of the different downstream sectors for GORTT over the coming years.

The iron/steel industry has and is likely to continue to provide poor netback gas prices to T&T. We understand that the iron/steel plants are significant employers and as such they will provide benefits to GORTT and the people of T&T from direct employment and multiplier effects that should be set against the low gas prices that they are able to afford. However, Poten has not been provided with sufficient data for the iron/steel sector to enable a calculation of historical GORTT take from their gas value chain or to assess the impact of employment / multiplier effects on the local economy. Set against the employment / multiplier effects, the iron/steel sector also imposes a significant cost on T&T in the low/subsidised power prices that we understand that it pays for the significant quantities of power that it consumes. Again, Poten has not been provided with sufficient data to enable us to quantify this impact. Taken as a whole, it is unlikely that any of these other factors would significantly improve the position of the iron/steel sector in the ranking of relative sector attractiveness provided by the netback gas price analysis.

Development of the local skills base is discussed in Sections 15 and 17, although it should be noted that Poten does not see any strong grounds for differentiation between the various gas consumption sectors on the grounds of local skills development.

12.2.1 Curtailment

12.2.1.1 Management of Shortfalls

As described in Section 11, since 2007 and more significantly since 2010 there have been shortfalls in contracted gas supply to the downstream industries, due to combination of factors; insufficient gas deliverability on the part of upstream suppliers, the contractual inability on the part of NGC to impose firm volume commitments upon suppliers and, periodically, operational upsets which impact a supply which cannot be compensated for by the remaining producing fields. To date the shortfall situation has been managed through three distinct processes:

- The management of gas supply between ALNG and NGC, which is in effect bpTT and to a lesser extent BG determining the split of its gas supply between ALNG and NGC. BG physical supply from NCMA is linked directly to ALNG but supply from ECMA is not.
- ALNG shareholders allocating gas across ALNG trains.
- NGC managing the supply to downstream industries imposing cuts on a pro rata basis across the industries while maintaining supply to the power and domestic sectors.

The underlying premise in the existing process, at least in regard to NGC's position, has been that gas supply shortfalls are short-term phenomena and that following a shortfall there will be a reversion to full supply. Indeed expiring downstream contracts have been renewed by NGC at their existing ACQ levels. However, in recent years it has become clear that the shortfalls are not temporary aberrations, but a more fundamental lack of gas deliverability, and the analysis undertaken in Section 11 shows that this situation will continue at least until 2016 when a number of NGC downstream contracts will expire.

Poten's analysis of upstream operator plans shows that a plateau of around 3.7 Bcf/d of supply to downstream is feasible assuming that investment decisions are made on a timely basis. If future gas supply is lower than the forecast new production plateau then the contractual shortfall situation could be exacerbated and accelerated.

The existing contractual shortfall situation through to at least 2016 and its potential future extension is such that there will be a need for active management of supply into consumption. Given the knowledge that there is insufficient supply to meet the volume requirements of remaining contracted supply it would not appear prudent for NGC to extend any of its contracts that expire before 2019.

12.2.1.2 Options for Dealing with Shortfalls

In considering the various options to manage the contractual shortfall in supply it is noted that GORTT has objectives and constraints:

- Maximisation of the value received for the gas – in a gas-constrained environment GORTT would like to see the gas directed towards the plants that offer the highest value for the resource.
- The maintenance of contract sanctity and the reputation of T&T as country which respects commercial relationships.

Furthermore, as discussed in Section 11, GORTT appears to have limited ability to control the allocation of gas, and has no direct control over the volume of gas sent to ALNG rather than to NGC. Any action to manage supply outside of the gas supplied through NGC is out of the direct reach of GORTT and would require intervention in the working of the sector.

There are three possible approaches GORTT could take, and these are set out in Table 12-1.

Table 12-1 Options for Dealing with Supply Shortfalls under Existing Contracts

Option	Mechanism	Pros	Cons
Non-Discriminatory (Current approach)	• Pro rata cuts to all buyers from NGC • Allocation takes place on an annual basis • Volume into LNG not determined by GORTT/NGC	• Respects contracts to the extent possible • Equitable for NGC customers • Transparent	• Does not ensure highest value for T&T • Ultimately may shut down high value plants if supply insufficient to meet operational requirements
Discriminatory: Centrally Planned	• GORTT would allocate gas according to value provided to T&T, including LNG & within NGC portfolio • MEEA would maintain value model and allocate volumes preferentially to higher value buyers • ALNG/NGC split may be established in PSC TCM meetings • Allocation takes place on an annual basis and "within" the framework of the existing contracts	• Maximises value to GORTT – economically efficient allocation	• Disproportionate cuts to low value buyers • Parties may not be willing to accept and may contest , although pricing to upstream could be maintained
Discriminatory: Market Based	• All contracts are cancelled and buyers tender for supply – competing on price for gas	• Maximises value to GORTT & upstream • Most efficient economic allocation – gas goes to the highest bidder at any given time • Encourages energy efficiency	• Highly complex to enact in practice • Requires abandonment of existing contracts • Disproportionate cuts to low value buyers • Parties would likely be unwilling to accept and would likely contest – potentially extensive litigation • Would create major upheaval in sector

The first option is to continue the management of short supply into consumption as at present, with the volume delivered into the LNG sector as currently determined by bpTT and to a lesser extent BG. NGC would continue to distribute its available gas between its downstream consumers on a pro rata basis. This option has the merit of respecting existing contractual arrangements as much as possible. It does not maximise value for GORTT and would result in some plants which provide relatively high value receiving less than their contracted volume.

The second option is for GORTT to become actively involved in the allocation of gas in the sector, participating in the control of the flow of gas to LNG plants as well as directing the flow of gas within the NGC portfolio. GORTT would need to be actively involved in the decision making around the ALNG /

NGC split of gas. One potential option for this GORTT involvement in directing gas flows from PSC contracts would be within PSC TCM meetings, under which GORTT could direct require suppliers to preferentially direct gas to highest value uses. Relative value to GORTT of the difference consumers would likely be determined by a model maintained by MEEA, with support from NGC.

This option would allow GORTT to optimise value within the existing contract portfolio. GORTT would be taking a direct interventionist approach in directing gas supply. In directing gas towards the buyers able to provide the highest value, it should be possible to maintain the level of pricing that the upstream suppliers presently obtain. This would reduce some of the scope for resistance from upstream suppliers, although several suppliers would prefer to see the gas directed as it as a present as they benefit from the value gained in parts of the value chain outside of T&T.

In regard to NGC's downstream portfolio the contentiousness of this approach would depend upon how gas is allocated by NGC. If NGC continues to honour existing contracts on a pro rata basis as at present then there would be little reason for downstream industries to object, as this is the process that is followed at the present and in this case more gas may be available for downstream industries.

If NGC were to adopt a remit to fully maximise value then there would necessarily be selective allocation to downstream industries. For any form of preferential allocation to selected users, those that provide lower value would receive less gas in a shortfall situation. The offtakers who suffer the greater shortfalls may contest this allocation which may ultimately result in extensive and costly litigation.

The third option is also interventionist, but rather than a centrally-planned approach to allocation the short supply would be directed towards the users that would be prepared to pay the highest price. This would entail developing a marketplace for gas with the various buyers bidding for gas volumes. This would be the most economically efficient allocation of gas and would encourage efficient energy use. In this third option it would be possible to establish full price discovery – the price a buyer is prepared to pay.

However, in practice this would be a highly complex system to set up and manage. Buyers would be required to tender for supply through a process that is transparent and equitable. This would need to be a managed process as T&T does not have the depth of gas market to create a truly competitive market.

This option would require the abandonment of existing contractual relationships between buyers and sellers and would likely take many years to implement. It would very likely result in extensive litigation between the various industry players and GORTT/NGC. It may also require abandonment of the netback pricing that has been used effectively in T&T with gas sales to the downstream industries as continuing this practice would require a means of normalising indices would be necessary to compare the offers.

Given the needs of the gas sector to promote the development of new gas as soon as possible which will require the participation and cooperation of the entire industry it is not possible to see how this approach could be implemented without creating a major upheaval to the sector, regardless of the issues around contracts and legislation.

12.2.2 Future Downstream Contracts

12.2.2.1 Existing Situation

T&T has a current downstream portfolio that could consume an estimated ~4.3 Bcf/d of gas while supply to downstream is only expected to be maintained at around 3.7 Bcf/d. At this level of supply there is projected to be no excess supply over contracted downstream sales until contracted volumes drop to

~2.8 Bcf/d from 2019 with the expiry of the contracts to supply ALNG Train 1 and almost all of T&T's ammonia capacity. Given this situation it would not appear feasible for NGC to extend any of its contracts that expire before 2019 with the knowledge that there is insufficient supply to meet the volume requirements of remaining contracted supply.

This means that a more selective approach to downstream contract renewals will inevitably be required in future, rather than the apparent approach of NGC to date which has been to extend expiring contracts for 5 years in the hope the supply and demand situation will improve. Any approach taken will also have to include LNG in its analysis of which contracts to extend, which has not been an issue to date.

As under the contractual shortfall situation, GORTT should be seeking to maximise the value received from the gas produced, which in an environment where demand cannot fully be met means directing gas towards the plants that offer the highest value for the resource. This is not happening under the present system of all contracts being extended without apparent analysis of their relative value to GORTT.

12.2.2.2 Options for GORTT

In Poten's view there are three possible approaches GORTT could take towards renewing downstream gas supply contracts and these are set out in the table overleaf. Each of the options seeks to maximise value from GORTT's perspective.

The first option is for a centrally-planned approach under which GORTT would determine which buyers receive new gas contracts based upon the expected value of terms offered, directing incremental supply to the expected highest value consumers. As LNG would have to be included in this analysis and considered on a comparable basis with the other downstream industries, it is difficult to see how such a system would be workable without NGC acting as the sole buyer of new gas from upstream and the sole seller of new supply to downstream, i.e. expanding its current downstream portfolio to include supply to LNG. This potential expansion of NGC's role is discussed further later in this section.

The second option is also a centrally-planned approach under which new supply would be tendered out to all prospective buyers who would compete on price to secure supply. Again it is difficult to see how such a system would be workable without NGC acting as the sole buyer of new gas from upstream and the sole seller of new supply to downstream. Otherwise a tendering process to determine which downstream consumers should get supply would then need to match them up against upstream supply tranches, which in Poten's view is unlikely to be practical. Although a tendering process has the advantage over the first option of providing a transparent and fair price discovery process, there a number of issues that question the viability of this option:

- It is not clear how it would be possible to establish tender parameters between different commodity offtakers that would offer a basis for comparing prices across different downstream sectors. It would potentially be possible to require all buyers to bid fixed prices or against a HH gas reference, but this would involve a complete move away from the commodity-linked gas prices which act as risk/reward sharing mechanism between gas supplier and buyer, are generally well understood and accepted by industry stakeholders, and have worked well to date in T&T with the petrochemical industries, although less well for LNG.
- It is also difficult to see how competition could be generated between plants with contracts expiring at different times, e.g. contracts to methanol expiring in 2015/16 and to ALNG Train 1 expiring in 2019. The closure of a petrochemical plant is not necessarily a permanent event as these facilities can be mothballed for significant periods of time and

restarted. There are a number of examples of methanol and ammonia plants in North America that have been closed up to 10 years and restarted. There is, however, a cost to mothballing a plant and a plant owner would need to have a clear view of future gas supply and economics in order to make a decision to mothball a plant.

Table 12-2 Options for Contracting Future Gas Supply

Option	Mechanism	Pros	Cons
Centrally-Planned Approach: Allocative	• GORTT directs incremental supply to expected highest value, determining which buyers receive new gas based upon expected value of terms offered, including LNG • Implication is that NGC is sole buyer of new gas and sole seller of new supply	• GORTT seeks to maximize the value obtained from its gas resources • NGC could offer a basket price to suppliers or direct high cost supply to high value demand (matchmaking), ensuring an adequate price to marginal supply • Should be a relatively workable option	• Requires significant GORTT intervention in the sector • Allocating supply will not be a transparent process • Will rely on projections of expected future value to GORTT – highly dependent on future commodity price projections
Centrally-Planned Approach: Tendered	• New supply tendered out to all prospective buyers who compete on price • Implication is that NGC is sole buyer of new gas and sole seller of new supply	• As above • Transparent and fair price discovery process	• Complexity in establishing tender parameters between different commodity offtakers • Could only generate competition between plants with contracts expiring at the same time
Market-Based Approach	• Buyers/sellers free to transact with each other • NGC reduced to providing transportation services only • Domestic market obligation required to ensure supply to the local market (power etc.) • Needs oversight to ensure arm's length pricing and avoid transfer of value downstream / offshore	• Economic theory suggests this should give an efficient allocation	• In shortfall situation low-cost suppliers pick off high-value buyers leaving higher-cost supply with lower-value buyers • Unbundling would require significant time/effort and development of new regulatory capacity • Rent presently captured by NGC would be moved upstream, to be shared with upstream contractors

The third option involves a market-based approach whereby NGC's wholesaler role would be removed, except potentially for small consumers, and upstream suppliers and downstream plants would be free to contract with each other. NGC's role would be reduced to that of gas transporter. This option is again discussed in detail later in this section.

From an economic theory perspective a market-based approach should give an efficient allocation of scarce gas resources. However, there are a number of key drawbacks to this approach:

- Removal of the intermediary role may well lead to reduced economic rent which is currently captured by NGC in the midstream and ultimately distributed back to GORTT as a dividend.
- There is a valid concern that given the structure of the market that the strongest upstream incumbents could use their position to cherry-pick the best customers, leaving those with less competitive supply without access to viable markets.
- The transition from NGC holding a merchant position to market participants negotiating contracts directly will be a process that would need to be undertaken over a period of time. Given the mature nature of the sector and the likely future decline of overall gas supply, it is questionable whether such a major change to the structure of the sector, which would inevitably take a number of years to implement, would be worthwhile and in the best interests of T&T.

12.3 SECTORAL STRUCTURAL ISSUES & THE ROLE OF NGC

12.3.1 Background

At the present time the T&T natural gas market structure could be characterised as the single buyer structure although it retains many features of the vertically integrated model (these models are discussed in Appendix J). The key features of the current structure are as follows:

- There is limited competition in the upstream supply of gas with 4 major players and several small producers. The major producer is bpTT, which holds ~60% of the total gas production and presently holds ~ 55% of the proven reserves.
- Transmission and distribution are undertaken in a single system by a transmission system operator, in this case NGC. NGC also acts as the sole wholesaler of gas, purchasing from suppliers to market to the downstream industries, the power sector and small customers. Transportation is provided as a bundled service with gas supply. There is a bypass of NGC as two suppliers, bpTT and BG, supply gas directly to ALNG. This represents ~55% of total gas consumption.
- The downstream sector of the is comprised mostly of large consumers requiring baseload gas supply whose products go for export. The domestic market is very small representing around 10% of total gas consumption into power, cement and small consumers.

There is a significant degree of vertical integration in the sector:

- bpTT is a major player throughout the gas chain. As well as being the dominant upstream player it has downstream interests in the Atlas methanol plant and is a major shareholder in ALNG.
- BG, the second largest upstream player is a shareholder in ALNG and a major LNG offtaker through Trains 2, 3 & 4.
- NGC is integrated throughout the chain, as discussed below.

12.3.2 Current Role of NGC

NGC was incorporated in August 1975 as a state-owned corporation. The stated objective of NGC regarding natural gas is:

- To carry on in all or any one or more of its branches the business of buying, selling, transporting, manufacturing and processing as including natural gas and products thereof.[1]

NGC is the dominant, indeed the only, player in the midstream sector and covers a multitude of roles, not just in the midstream but across the whole hydrocarbon sector. Inter alia the company undertakes the following activities:

- The company is the sole wholesaler of gas to the downstream and industrial sector, and in this role acts as the aggregator buying gas from the upstream suppliers and selling to the downstream buyers.
- The company is the owner and operator of the midstream transmission infrastructure and acts as the monopoly transporter of gas to the downstream sector. This service is not explicitly

[1] Section 3(i) Memorandum of Association of the National Gas Company of Trinidad and Tobago Limited.

offered for the most part as it provides a bundled tariff of gas and transportation to the downstream buyers.

- The company has, through wholly-owned subsidiaries, shareholdings in a number of E&P assets. It has a 15% interest in the Teak, Samaan and Poui fields acquired from bpTT and 30% and 8.5% interests respectively in two blocks comprising the Angostura field, which were acquired when Total left T&T. It also has a 20% share of Trintomar. A number of these assets are gas producing.
- The company, via subsidiaries, is a shareholder in Trains 1 and 4 of ALNG and also an offtaker from Train 4.
- Via subsidiaries, NGC now holds ~82% equity interest in PPGPL, the country's sole cryogenic gas processing facility
- The company acts as the business development arm of the local gas industry through NEC, a wholly-owned company, charged with bringing in new investors to the sector. In this role it is involved in the granting of investment incentives for new developments.

There are a number of issues related to the existing roles of NGC in the sector:

- Although various references mention that NGC and has a mandate from GORTT to function as the sole aggregator, and in some cases, as the transporter of natural gas, there is no clear authority either in legislation, or the company's charter for this proposition. Rather than being a statutory monopoly, such a Petronas in Malaysia, NGC is a natural monopoly by virtue of its dominant position as aggregator and transporter, in effect operating as a 'national champion' in the absence of a national oil company. At present MEEA and MOFE oversee NGC activities, but it is not clear what criteria are applied in this oversight – service to the internal market, employment of nationals, dividends to the treasury etc.? There appear to be no formal criteria applied in regard to its merchant role as single buyer and the sole provider of transportation services in the country, or in terms of its service obligations or pricing despite its monopoly position in the market.
- Conflicts of interest. As highlighted above NGC is playing multiple roles in the gas sector supplier, buyer, aggregator, transporter, seller and product offtaker, and the potential for conflicts is high. While there is no question that as a GORTT-owned company NGC management is intent on acting in the national interest, there will inevitably be events where the specific interests of NGC as a shareholder may be different from that of GORTT. NGC will be seeking to optimise value within its sphere of activities whereas GORTT will be seeking to optimise value across the entire value chain.
- Transparency. The fact that NGC offers only bundled services means there is a general lack of transparency in the sector.
- Market pressure on wholesale margins. Market forces will increasingly put pressure on the intermediation role that NGC adopts as the wholesaler to the sector. Upstream costs have increased substantially over the last decade, which has inevitably led to a requirement for higher wellhead gas prices to support new developments. The prices that downstream users are able to sell at in global markets have been historically high over recent years but have declined significantly in 2015 and are not expected to regain previous highs in the short to medium term. As a result, NGC's margins are likely to be squeezed over time. Hitherto NGC has been able to manage to keep an attractive overall margin between purchase and sales prices but this may be more challenging going forward.

- Aggregation. The changing supply and demand balance from surplus to deficit has been very challenging for NGC over the past few years in its role as aggregator. Central to the role of aggregation is the provision of a secure supply of gas to all customers. In principle, NGC with access to multiple sources of supply should be able to provide an uninterrupted supply to users. However, due to the decreasing availability of upstream gas supply and gas supply capacity, NGC has been unable to meet its downstream contractual commitments. Numerous gas shortfalls have been experienced across the sector (with the exception of power and small consumers who are ring-fenced) which have been "managed" by declaring force majeure. NGC is now in a position where it has to distribute the shortfall of gas through an allocation process, for which there is no agreed procedure, and which is a subject of some concern for downstream buyers.
- Concentration of expertise. As NGC undertakes numerous roles in the T&T gas sector the overall know-how of the sector is highly concentrated in this organisation. Given the high importance of the gas sector to the T&T economy there is some concern as to the national dependence on one organisation.

It is understood that the issue of regulating NGC's role in the natural gas subsector was raised in the 2002 Master Gas Plan. Vision 2020: Draft National Strategic Plan went further by recommending that "Government must divest its ownership of all energy related companies on the local capital market".

12.3.3 Options for Future Sector Structure / Role of NGC

Drawing on the existing experiences within the gas sector in T&T as well as the global experiences outlined in Appendix J, there are evidently some options for the structure of the gas sector in T&T and the role of NGC that would address some of the issues identified above and potentially enhance the operations of the sector.

12.3.3.1 Maintain the Status Quo

This option would represent a continuation of the current situation, whereby NGC buys gas from upstream suppliers and sells gas to downstream consumers (excluding ALNG). NGC also continues to participate in the sector as a shareholder in a number of ventures including upstream, ALNG, PPGPL etc.

Rationale

Historically the intermediary role NGC has taken on as merchant wholesaler and aggregator buyer has been critical to the development of the sector. The market-making function has been key to attracting new downstream development. Although various issues identified above are impacting the successful operation of the sector, and the challenges of the sector are now very different to those of previous years, there are arguments in favour of maintaining the current structure:

- The structure of the sector is well understood by the various stakeholders and has served T&T relatively well to date.
- The existing situation may be deemed to be better than all the alternatives.
- Small/subsidised consumers. The aggregation role allows NGC to spread the gas supply costs across all gas suppliers, effectively cross-subsidising some consumers. This is notably an issue for the power generation sector for which the power prices are controlled at a low level by GORTT and the iron and steel consumers which typically have low gas affordability.

- There would be no need to implement any sort of complex restructuring implementation, which would inevitably stretch limited GORTT/MEEA resources.
- Power incumbents, including NGC, are understood to be relatively comfortable with the status quo.

Issues

However, there are a number of issues with maintaining the status quo:

- In line with the upstream situation detailed in Sections 7 and 8, the status quo has failed to provide the gas supply necessary to avoid shortfalls over recent years.
- NGC will increasingly be caught up in major conflicts of interest as decisions on where gas gets allocated occur more frequently.
- NGC's wholesale margin will likely be subject to erosion as higher gas prices are expected to be needed to advance future upstream developments (as discussed in Section 8) and realised commodity prices downstream are expected to be lower than over the past 5 years (as discussed in Section 9).
- Volume mismatch risk between upstream and downstream will remain with NGC and this is likely to become a more serious issue in a gas shortfall situation that is likely to increase over time.

12.3.3.2 NGC Becomes Single Buyer for all Gas in T&T

Under this option for all future supply NGC would become the single buyer of upstream gas and wholesaler of gas to downstream industries, i.e. expanding NGC's role to include supply to ALNG and not allowing the bypass of NGC (direct gas supply agreements between upstream and downstream).

Rationale

NGC's current wholesaling activity provides a means for GORTT to extract substantial rent from the midstream section of the gas business in the form of earnings from NGC's wholesale margin, particularly from the ammonia and methanol sectors, as discussed in Section 10. This economic rent is ultimately distributed back to GORTT as a dividend and is 100% to the benefit of GORTT or GORTT-owned entities, although it should be noted that NGC appears to have a history of reinvesting earnings for expansion of its commercial presence rather than dividending the revenue back to GORTT. If the margin on gas wholesaling was passed through to the upstream then GORTT would have to share the upside with the upstream suppliers as per the terms of the various upstream agreements.

As also discussed in Section 10, GORTT capture of economic rent from the LNG value chain has been far less effective and inserting NGC as the sole gas supplier to ALNG, post-expiry of any existing contracts, may provide GORTT with the most efficient way of capturing additional rent from LNG.

In addition, this option would allow NGC to manage gas supply to the whole downstream sector, whereas at the moment it has limited control of how much gas is supplied to LNG. This is of particular relevance in a gas shortfall situation, as discussed earlier in this section. NGC would also be able to offer an element of LNG-linked pricing to upstream, if this is required to stimulate new upstream investment (as discussed in Section 8).

Issues

There are a number of issues that would be raised by this option:

- NGC would be extending its monopsonist powers to the whole sector. This would increase the oversight required of NGC's activities to ensure that it is acting in the broadest interests of GORTT rather than its own more limited perspective.
- The sector will continue to lack transparency, although in practice no more so than at present.
- The volume risk that NGC is exposed to will need to be carefully managed by the future contractual provisions put in place between NGC and both gas suppliers and buyers (as discussed in Sections 5 and 9) to avoid a continuation of the existing situation, e.g. inappropriate reliance on Force Majeure.
- LNG incumbents will likely oppose and changes to the status quo as they have extracted substantial value from the existing arrangements. Upstream players with aspirations to supply gas to ALNG (and offtake the corresponding LNG) will also oppose the insertion of NGC into the value chain. Future options for LNG structuring are discussed in greater detail later in this section.

12.3.3.3 NGC Business Refocused on Wholesaling and Transmission

Under this option NGC would strictly be limited to a gas wholesale and transmission role. The remainder of its assets would be divested, potentially either to another GORTT-controlled entity or to a new entity or entities to be listed on the local stock market.

Rationale

As well as the provider of gas transportation and the sole wholesaler of gas to downstream industries (excluding LNG), NGC also has the following activities:

- Through wholly-owned subsidiaries, shareholdings in a number of E&P assets. It has a 15% interest in the Teak, Samaan and Poui fields acquired from bpTT and 30% and 8.5% interests respectively in two blocks comprising the Angostura field, which were acquired when Total left T&T. It also has a 20% share of Trintomar. A number of these assets are gas producing.
- Again via subsidiaries, NGC is a shareholder in Trains 1 and 4 of ALNG and also an offtaker from Train 4.
- NGC now holds ~82% equity interest in PPGPL via subsidiaries, the country's sole cryogenic gas processing facility.
- NGC acts as the business development arm of the local gas industry through NEC, a wholly-owned company, charged with bringing in new investors to the sector. In this role it is involved in the granting of investment incentives for new developments.

Other than the fact that much of GORTT's expertise in the operation and management of the gas sector in T&T is contained within NGC, there is no obvious reason as to why NGC is the best undertaker of these roles or holder of these assets. In particular, NGC holding upstream gas assets creates a clear conflict of interest in its role as monopoly gas buyer for downstream industries. There is also a concern from a GORTT perspective that NGC has used funds to acquire assets that should have been dividended back to GORTT, and that this should not happen in future. Paring NGC back to its core wholesaling and transmission activities would address these issues.

Issues

There are a number of issues that would be raised by this option:

- NGC has been acquiring assets and expanding its role over recent years. NGC would likely oppose any moves to strip it of existing assets.
- GORTT would have to decide how best to transfer ownership or sell these assets
  - Ownership could be transferred to new or existing GORTT entities whose core activities would be more aligned with the assets, e.g. NGC's upstream assets could be transferred to Petrotrin.
  - A new entity or entities could be set up to own the assets and be listed on the local stock market.
  - The assets could be sold to new investors.

12.3.3.4 Allow Large Buyer Bypass of NGC Wholesale Function

This option would allow large industrial buyers to bypass NGC and buy directly from suppliers, negotiating their own terms. The bypass already exists for supply to ALNG and apparently exists in theory for other downstream industries, if not in practice.

Rationale

The gas market in T&T is now at a stage of maturity and low growth such that the need for the market-making function performed by NGC to date is much diminished. Indeed it can be argued that the role of NGC is complicating the operation of the sector as it struggles to match supply with demand and that for large buyers this would be better handled by large buyers and sellers interacting directly.

From a theoretical economic viewpoint it is difficult to find a justification for the continuation of NGC's role as supplier to gas to the large downstream industries. These industries are all of sufficient size to have bargaining power with suppliers. At the present time NGC is going to great trouble to match the contract structure of suppliers with that required by consumers, e.g. for the ammonia industry buying and selling gas on an ammonia linkage and similarly for the methanol industry. This intermediary role adds cost as NGC has to maintain staff to negotiate contracts, and must also add a margin to the price to ensure that the company is not exposed in the portfolio, as supply and demand are not perfectly matched. Putting buyers and sellers together directly would remove these intermediation costs and allow each buyer and seller to negotiate exactly what they need in term of risk management directly without the costs of having a middleman in the chain.

The removal of NGC from the supply chain for large industries would also remove NGC from the responsibility of assuring security of supply. It would be the responsibility of downstream buyers to negotiate an appropriate penalty regime with suppliers to provide the necessary security and provide adequate compensation for the shortfall, with NGC reduced to providing transportation services for the gas.

Issues

There are a number of issues and concerns that would need to be addressed:

- Removal of the intermediary role may well lead to reduced economic rent which is currently captured by NGC in the midstream and ultimately distributed back to GORTT as a dividend.

- Small/subsidised consumers. The aggregation role allows NGC to spread the gas supply costs across all gas suppliers, effectively cross-subsidising some consumers. Removal of the large consumers would vastly diminish the ability of NGC to aggregate supply, and specific attention would need to be given to gas availability and pricing to small consumers.
- This option implies a purely market-driven solution to the future recontracting of gas supplies, i.e. the market will decide which downstream plants are shut off in a situation where gas supply is insufficient to fully meet demand.
- Competitive position of incumbents – there is a valid concern that given the structure of the market that the strongest upstream incumbents could use their position to cherry-pick the best customers, leaving those with less competitive supply without access to viable markets.
- Implementation. How will this be done? The transition from NGC holding a merchant position to market participants negotiating contracts directly will be a process that would need to be undertaken over a period of time. Given the mature nature of the sector and the likely future decline of overall gas supply, it is questionable whether such a major change to the structure of the sector, which would inevitably take a number of years to implement, would be worthwhile and in the best interests of T&T.

12.3.3.5 Unbundling of Transportation Services

The provision of transmission services could be unbundled from the present fully-bundled gas supply service provided by NGC, with gas and transportation capacity provided as separate services. A separate gas transmission entity would be established to operate the pipeline system, provide pipeline capacity to shippers and manage the system through the balancing of gas. Gas buyers or sellers would contract for pipeline capacity with the new gas transmission entity on a transparent basis. Secondary trading of capacity would be allowed so that capacity holders could manage their capacity rights efficiently. Tariffs would be set based upon recovering system capital and operating costs over an appropriate period of time.

Rationale

The provision of third party access to the transmission system is essential to allow for the previous options involving the bypass of NGC to be enacted, as otherwise the transportation provider could refuse access to protect its monopoly market position.

The system would continue to be owned and operated by NGC but there would be regulatory oversight by an independent regulatory body that would oversee tariff setting and access regimes. NGC would be required to have separation of accounts that relate to the ownership and operation of the pipeline system. NGC already operates and runs the transmission system so the creation of a separate entity to do this would be largely an administrative and accounting exercise.

Issues

There are several issues and concerns with this option that would need to be addressed:

- The unbundling of transportation services would have a cost. Operating practices and rules, tariff structures and payment systems would need to be developed and commercial accounting systems developed.
- There would need to be a network code for all users.
- The major effort required in the development of third part access will be in the regulatory area. There will be cost involved in the establishment of the regulator but perhaps the great

challenge will be finding suitably qualified people to staff the regulatory function. At present the "know how" in the sector largely resides within NGC, and this would need to be distributed more widely. If the regulatory function was to sit with MEEA then its resources and capacity would have to be bolstered accordingly.

12.3.3.6 Fully Liberalised Market

This is the ultimate development of the previous options relating to NGC bypass and transportation unbudling, allowing all buyers to bypass NGC and contract directly with suppliers. NGC's role would be reduced to that of transportation provider.

Rationale

By freeing up buyers and sellers to transact with each other, the objective would be in the long term to provide a basis for a more competitive market structure by putting in place the mechanisms to allow competition to develop by removing all barriers to entry. This option would facilitate greater transparency in pricing and remove some of the concerns regarding the potential for discriminatory treatment under the existing arrangements. The need for an intermediary, NGC, would be removed.

Issues

There are a number of major issues and concerns with this option:

- In Poten's view it is unlikely that the T&T gas market is sufficiently deep or liquid to support this option.
- Removal of NGC's role may well lead to reduced economic rent which is currently captured by NGC in the midstream and (generally) distributed back to GORTT as a dividend.
- bpTT, for example, has a dominant market position in regard to upstream supply and controls significant infrastructure capacity. Independent oversight would be essential to ensure that no anti-competitive behaviour takes place. However, it would be challenging for GORTT to ensure that all transactions would be truly arm's length in order to avoid shifting value along the chain or offshore.
- The issue as to how small consumers are dealt with would become particularly pertinent. No upstream supplier will want to sell gas to consumers that can only afford low prices. The issue of subsidised gas would need to be dealt with directly and some sort of DMO to ensure supply would likely be required.
- In a shortfall situation low-cost suppliers could potentially pick off high-value buyers leaving higher-cost supply with lower-value buyers, potentially making supply uneconomic and resulting in stranded gas.
- The issues in relation to the unbundling of gas transportation services would remain as described above.
- This option would require significant time/effort and development of new regulatory capacity.

12.3.3.7 Options Summary

A summary of the various options for the future structure of the sector and the role of NGC detailed in this section is included overleaf.

Table 12-3 Options for Gas Sector Development – Role of NGC

Option	Rationale	Implementation Requirements	Comments / Issues
No Change	• The existing situation is better than all the alternatives	• Business as usual	• NGC will increasingly be caught up in conflicts of interest as gas allocation decisions occur more frequently • NGC margin will be subject to erosion • Volume mismatch risk remains with NGC
NGC becomes single buyer for all gas in T&T	• Efficient route for GORTT to extract value from LNG • Allows NGC to manage supply allocation to the whole sector • Would allow NGC to offer blended prices to suppliers	• As LNG contracts expire NGC incorporates supply to LNG into its wholesale portfolio	• NGC extends monopsonist powers to whole sector • Sector will lack transparency • Potentially increases NGC volume risk • Appetite of some upstream suppliers to accept basket pricing uncertain • Incumbents will likely oppose as existing LNG arrangements have generated substantial value for them
NGC business refocused on wholesaling and transmission	• Removes potential upstream conflicts of interest • Focuses NGC business on core skills	• Divestment of non-core assets (e.g. upstream assets)	• No obvious reason as to why NGC is the best owner of upstream assets • GORTT would have to reallocate divested assets • Could be combined with the role as a single buyer
Allow bypass of NGC by large buyers for new supply	• Increased transparency • Takes volume risk away from NGC • NGC able to aggregate supply from small suppliers if this service is required	• Would require transportation separation & tariff structure development • There would need to be DMO (or similar) on suppliers (~10%) to cover sales to power/steel etc.	• How to ensure that the available gas gets sold to the party willing to pay the most in a shortfall situation? Tender? • NGC presently extracts significant rent from the gas value chain for T&T – how to ensure this continues? Midstream taxation? • May result in NGC stagnation - left with lower-priced contracts in its portfolio.
Transportation services unbundled	• Would result in greater sector transparency	• Separation of transportation and gas supply functions of NGC • Tariff structure development • Regulatory oversight	• Where should the regulatory function sit? MEEA? • Would need to develop Institutional capacity of MEEA
Fully liberalised market	• Removes need for intermediaries	• Breakup of NGC - becomes transportation provider • Open access on the transportation system • Would require DMO for power/steel	• T&T market is not sufficiently deep or liquid to support this option • Not clear how to ensure that all such transactions are arm's length • Opportunity for shifting value along the chain and possibly offshore

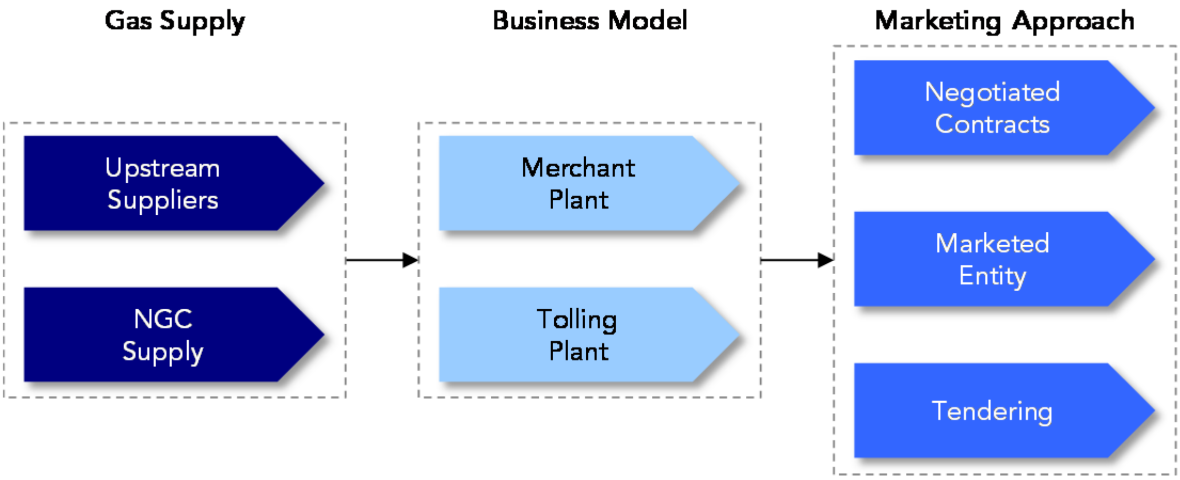
12.4 OPTIONS FOR LNG

Given that there are different taxation regimes between the upstream and downstream sectors, and no taxation on marketing activities for non-resident entities, this can give rise to opportunities for players to optimise their positions along the value chain in a way that does not maximise value for T&T. As such there is a need for oversight to ensure that transactions are carried out on an arm's length basis with the value optimised across the gas value chain. As discussed in Section 10, this has been a major issue to T&T in the LNG value chain over recent years where GORTT capture of economic rent from LNG has been far less than for the NGC-supplied ammonia (in particular) and methanol plants.

Although there may be options for GORTT to improve its share of the overall LNG chain take under the existing contractual arrangements, as discussed in Section 10, the main forthcoming opportunity for it to do so comes with the expiry of the existing ALNG Train 1 contractual arrangements, which we understand will take place in 2019. It should be noted that Poten has not been provided with any of the full legal documentation in relation to ALNG (project agreements, licenses, gas supply agreements, LNG SPAs etc.). As such the following should be considered as a general discussion of potential options and what may prove to be the most optimal route for T&T to take, rather than a specific assessment of what could be achieved in practice or how it would be implemented.

As shown in the figure below there are a number of different options that could be considered for various elements of the value chain, which are discussed subsequently.

Figure 12-1 Options for LNG



Considering the complexity involved, it is Poten's view that MEEA should already be dedicating resources to evaluating what the optimal approach should be in future.

12.4.1 Gas Supply

As per the expected future gas supply and demand situation discussed in Section 11, doubts over long-term gas availability will likely restrict future supply contracts to a maximum of 5 years. In addition, in a gas-short environment Train 1 will have to complete for supply with other downstream consumers. That said, as illustrated by the future projections in Section 11, revised LNG arrangements could comfortably offer GORTT the most attractive route for future gas monetisation.

There are two options for gas supply to ALNG post-expiry of existing contracts:

- Direct supply from upstream, bypassing NGC (continuation of the current model).
- Supply via NGC (expanding NGC's wholesale role to include LNG)

A continuation of the existing gas supply model to LNG is a realistic prospect. However, the purpose of reorganising the LNG value chain would be to ensure that more of the overall chain take flows back to T&T rather than being captured offshore. Under the current model this would mean that far higher prices would potentially flow back to upstream, where the take take has to be shared between GORTT and upstream contractors, potentially generating windfall profit for upstream producers. In addition, a situation would be created whereby all existing or potential upstream producers would prefer to supply to LNG rather than to NGC due to the likely significantly higher prices on offer. Also, incumbents with upstream and LNG positions (BP, BG) would be in a very strong position to monopolise supply to LNG, crowding out other potential suppliers.

NGC's gas wholesaling margin (minus costs) is essentially 100% to the benefit of GORTT. Therefore, inserting NGC into the gas supply chain to LNG could offer the most efficient route for GORTT to ensure that it maximises its take from the LNG chain. While higher price would be realised for LNG by T&T, the extent to which upstream would benefit from these prices would be determined by contractors' needs for higher gas prices to support new developments. NGC could manage this by offering an element of or full LNG-linked pricing to upstream, depending on the upstream supply in question.

In addition, as discussed previously, expanding NGC's wholesale role to include LNG would allow it to manage gas supply to the whole downstream sector, whereas at the moment it has limited control of how much gas is supplied to LNG. This is of particular relevance in a gas shortfall situation, as discussed earlier in this section.

That said, there are a number of issues that would be raised by this option:

- NGC would be extending its monopsonist powers to the whole sector. This would increase the oversight required of NGC's activities.
- The volume risk that NGC is exposed to by any mismatches between its upstream supply and downstream sales contracts will increase.
- Upstream players with aspirations to supply gas to ALNG (and offtake the corresponding LNG) will also oppose the insertion of NGC into the value chain.

12.4.2 Business Model

ALNG Train 1 operates under a merchant model whereby it buys gas from upstream and sells LNG/NGLs, with the price of gas remitted to upstream based on a percentage of the released LNG/NGL revenues. Unlike the tolling-type structures for Trains 2 to 4, this means that more of the overall chain take has tended to be captured by the plant as the realised prices have been higher than were envisaged when the project was sanctioned. On the flip side the plant is exposed to risk if the realised prices are lower than anticipated, which is not the case under a tolling model.

Considering the situation after the existing agreements have expired, the key for GORTT is to ensure that the chain take captured by the plant is minimised, as GORTT's share of the take here is lower than for upstream or an NGC wholesale margin. GORTT should seek to allow the plant a (largely) fixed fee for providing liquefaction services, i.e. in practice a quasi-tolling structure, replicating the existing model for

Trains 2/3, with the remainder of the LNG revenues passed back to NGC as the gas supplier. The fixed fee should be set at a reasonable level to provide a return to the Train 1 shareholders and cover their costs, taking into account that the asset has been fully amortised over the initial 20-year operational period.

12.4.3 Marketing Approach

While there is a valid discussion about which gas supply mode to LNG would provide the most value for GORTT, the reality is that it is in the existing LNG marketing arrangements that the very significant value loss to T&T has taken place. Much of the overall LNG chain take has been captured offshore T&T by trading activities, which fall outside of the T&T tax net. GORTT needs to ensure that this situation is not repeated under any future marketing arrangements, that LNG sales are at a fair, transparent market price and that sales arrangements are avoided which do not have the flexibility to cope with changing market conditions.

There are three options for T&T in terms of future LNG marketing:

- Negotiated medium / long-term sales to an LNG buyer or buyers, i.e. a continuation of the current model, although gas supply availability concerns will likely limit future contracts to a maximum of 5 years.
- Marketing LNG through an intermediary, potentially with some sort of profit-sharing mechanism.
- Tendering LNG sales to the highest bidder. This could be done on a spot/short-term basis (<2 years) or a medium-term basis (up to 5 years).

Negotiated sales remain the most common model in the LNG business, but the future situation in T&T is atypical in that is will involve new contracts for an existing plant, where no new plant investment is required, rather than a new LNG plant where long-term contracts are required to support financing. It is likely that GDF Suez and Gas Natural would be keep to extend the existing arrangements, but even if this model was maintained it would be difficult to see a justification for simply extending the current sales contracts unless GDF Suez and Gas Natural were prepared to pay at least as high a price as other potential buyers.

Marketing LNG through an intermediary is a possibility. This could be either a third party under a profit-sharing arrangement or a GORTT/NGC entity that would be responsible for marketing. However, the downstream LNG sales arrangements that the marketing entity would enter into would need careful consideration to avoid value being lost to GORTT or T&T being locked into prices that are no longer in line with the market.

Tendering is a sales mechanism that is gaining increasing traction in the LNG business as the number of market players, shipping / regasification availability, and overall liquidity increases. It is a transparent and competitive process which ensures that the best price is realised for sales over the period that is covered by the tender. It would prevent value capture by offshore marketing entities and, provided that the period for which cargos are tendered is relatively short, would avoid the problems of "out of the market" pricing under existing contracts.

12.5 RECOMMENDATIONS & IMPLEMENTATION

12.5.1 Dealing with Contractual Shortfalls

The challenge for GORTT is to balance the economic gains of long-term contracts to individual participants in the gas chain against the potentially larger benefits to national welfare as the result of restructuring the gas sector. Going forward, regulations to restructure the gas sector must be based on a thorough economic and legal analysis of the relevant contracts. Lacking access to these documents, the following is presented as a generalised discussion of the available options

Three options have been identified as the means for the reallocation of upstream production in response to a potentially extended period of shortfalls. In addition to the current status quo, where NGC makes across the board reductions, there are two options that involve a more extensive regulatory intervention in existing contractual and trading relationships. The full implementation of any of the options would entail some form of consultation and rule-making by GORTT, either through the MEEA, or possibly the Fair Trading Commission.

Regulatory intervention in gas markets has occurred when there is evidence of either anti-competitive behavior, or contractual arrangements are distorting gas supply. An example of the first situation was the investigation by the U.K. Monopolies and Mergers Commission in the mid-1990s under the 1973 Fair Trading Act and 1986 Gas Act, resulting in the break-up of British Gas[2]. In the case of market distortions created by long-term contracts, gas regulators in both Canada and the United States adopted rules forcing pipeline companies to unbundle gas supply from transportation services[3]. Additional measures, such as direct access to end-users in exchange for foregoing deficiency claims, or take-or-pay liability purchases were adopted in both countries as incentives for industry support.

Non-Discriminatory Reductions

Under current conditions, shortfalls are managed by NGC through pro-rata reductions to all users, irrespective of contractual commitments or price margins. Allocations are revised annually based on production forecasts from field operators. This is purely a discretionary action by NGC under a claim of force majeure, and MEEA neither intervenes in, nor expressly sanctions this action.

The legitimacy of this action depends upon the terms of the gas supply agreement. In this regard, there is an obvious internal conflict in the terms of the Sample Contract provided by NGC. Under Article 2.2 the Buyer is obligated to take and pay for gas, *". . . provided that Gas is available. . . "*. On first reading, the implication is that this is not a contract for firm commitment and that a shortfall in upstream supply would relive NGC of its obligation. However, a later provision in Article 3.1 contract states: *"Seller represents and warrants that it shall contract for the purchase, from producers of Gas, of supplies of Gas adequate to supply Buyer's requirements under this Contract as well as other obligations to third parties so as not to adversely affect or detract from the adequacy of service to Buyer"*.

Article 3.2 further obligates NGC to notify the Buyer *". . . of any anticipated curtailment of Gas supply . . . "*. The Buyer has the right to recover damages directly resulting from Seller's breach of contract under Article 13.1.

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[2] M. Stoppard, *Competition and Regulation in the Gas Industry: An Evaluation of the MCC Report on Gas in the UK,* Oxford Inst. Of Energy Studies (1995).
[3] D. Stickley, *Towards the Integration of Canadian and U.S. Natural Gas Import Policies*, Land & Water L. Rev. Vol. XXV, No. 1 (1990).

At best, the Sample Contract is ambiguous regarding NGC's exposure to damages for non-delivery resulting from a reduction in gas supply. Two factors could tip the balance against NGC. Firstly, as a general rule of contract interpretation, ambiguities are construed against the party that drafted the agreement. Secondly, 3.1 is a warranty rather than a covenant or promise. Again, the general rule of contract construction is that warranties are more strictly enforced that covenants.

NGC's exposure could be ameliorated by adopting curtailment regulations. Under Section 29 of the Petroleum Act the President can make such regulations as considered necessary regarding the conditions to be observed by licensees. The scope of the regulations would be as follows:

1) An obligation to limit interruption to end-users for a fixed period;
2) A financial liability to end-users if the gas supplier exceeds the period;
3) Monitoring and reporting of the gas supplier's compliance;
4) Coordination with end-users for interruptions due to annual maintenance; and
5) Preparation of a curtailment program to be implemented in the event of the interruption gas supply due to an emergency or diminution of supply.

Of course, GORTT could choose not to act and rely on NGC to manage its way through the period of the shortfall as it has been doing.

Interventionist Approaches

MEEA has stated that its main policy goal for the energy sector is to ". . . optimally exploit the country's hydrocarbon resources ensuring its efficient administration in order to obtain the greatest returns to the country for the benefit of all citizens." In adhering to this goal, under the interventionist options MEEA would allocate gas according to the value provided to GORTT.

Under the allocation approach, the allocation of gas supply both between ALNG and NGC and within NGC's portfolio would be administered on an annual basis, and as consistently as is possible within the framework of the existing contracts. From a regulatory perspective, this would require the establishment of a mechanism where delivery obligations were limited to annual quantities.

The market-based option is the most extensive. As of a date to be determined, all existing supply contracts would be terminated by an order of GORTT. An administrative marketing centre would be established with all buyers competing at auction for supply on the basis of price. This approach would imply that either NGC's role is reduced to that of transporter or that its wholesale role is expanded to include LNG, as discussed elsewhere in this section.

The prospect of regulations being promulgated under the Petroleum Law raises several issues regarding the implementation of either of the interventionist approaches. The first concern is whether the adoption of either option would conflict with obligations under either the PSC or the E&P License. The answer depends upon the terms contained in the PSC. For example, some versions of the PSC make approval of the Contractor's proposal for marketing natural gas subject to the condition that such an arrangement "does not constitute a breach of anticompetitive or antitrust legislation to which the Contractor is subject to". Interestingly, this limitation was removed from the Model Deepwater PSC. Additionally, each PSC would need to be reviewed to determine whether, and to what extent, the application of the Petroleum Act and Petroleum Regulations had been specifically excluded in accordance with Subsections 6 (3) and (4) of the Act.

Additionally, it is possible that a PSC could contain a so-called "Stability Clause". A stabilisation clause can be defined as a provision that seeks to secure the economic balance in the contract against future government action or changes in the law without consent of the other contracting party. The purpose of the Stability Clause is to protect the economic position the Contractor gained through negotiation from being eroded by either higher taxes, or increased costs of compliance.

The fact that regulations had not been promulgated at the time the PSC or License came into effect is immaterial, as GORTT has the inherent right under prevailing legislation to regulate petroleum operations. As observed in the Parkerings award each state has an "undeniable right and privilege to exercise its sovereign legislative power" which includes the "right to enact, modify or cancel a law at its own discretion".[4]

The final concern is whether a commercial party in the gas chain could claim that market restructuring regulations represented a form of confiscation, expropriation or nationalisation (CEN) for which compensation would be payable either under domestic law or international treaty? The Constitution of T&T does not address compensation for the taking of intangible property such as contractual rights. Bilateral investment treaties commonly contain provisions that require compensation to be paid.[5] For example the bilateral investment treaty (BIT) with the United Kingdom contains the following language in Article 7 Expropriation: *". . . except for a public purpose related to the internal needs of that Party on a non-discriminatory basis and against prompt, adequate and effective compensation."*

In the case of PSC Contractors and License holders their gas supply contracts would not be terminated or cancelled under the allocation option. In this regard, it is further interesting to note how carefully this question was approached by the FERC in restructuring the US gas market under Order 636. The regulator denied that property had been taken through the separation of transportation from sale of gas because no contracts had been expressly terminated.[6] The regulator's approach was upheld in the face of industry challenge.[7] The most obvious course of action would be to create a mechanism in the regulation that arranges for the upstream supplier to receive a gas price that is equivalent to that received under its existing arrangements, thus obviating any economic impact.

The market-based option is more far reaching and would have a more pronounced impact on parties that are further downstream in the gas chain, such the offshore LNG trading companies. Presumably, the sellers have entered into an investment agreement that comes within the scope of a BIT. Again, each investment agreement along with the sales contract would need analysis. Buyers that on-sell the LNG at international margins, would not have the benefit of being a party to PSC or project investment agreement. As their transactions occur completely outside of T&T, they would not appear to have any status to make a claim under domestic law or a BIT.

Whether these or other issues would be an obstacle to implementing either regulatory option to restructure the gas market in T&T would require a review of the conditions of each PSC, E&P License, investment agreement and LNG export supply contract. In addition, MEAA would need to consult with the Office of the Attorney General regarding the application of T&T's jurisprudence on the nature of compensable

[4] *Parkerings-Compagneit AS v. Lithuania Award*, ICSID Case No. ARB/05/8, IIC 302 (2007), dispatched 11 September 2007, cited in Wood Mackenzie.
[5] The Government of Trinidad and Tobago has entered into 13 such BIT's.
[6] FERC, Order No. 636-A Order Denying Rehearing in part, Granting Rehearing in part and Clarifying Order No. 636, August 3, 1992.
[7] Panhandle Eastern Pipeline Company v. Federal Energy Regulatory Commission**,** 890 F.2d 435, 281 U.S.App.D.C. 318 (1989). American Gas Association v. FERC, 912 F.2d 1496 (1990), cert denied, 111 S.Ct 957 (1991).

property interests. It is understood that MEAA would not act to intentionally impair the sanctity of contracts.

12.5.2 Future Downstream Contracts, Sector Structure & Role of NGC

It is clear that the original drivers behind NGC's adoption of an intermediary / wholesaler role in the T&T gas sector no longer exist. The industry has moved from a growth / development phase of plentiful gas supply where a market-making function was required, into maturity, and is now facing the prospect of a situation under which gas supply is highly unlikely to be sufficient to fully meet demand going forward. Indeed it can be argued that the role of NGC is complicating the operation of the sector as it struggles to match supply with demand and that for large buyers this would be better and more economically efficiently handled by large buyers and sellers interacting directly.

However, from GORTT's point of view the key factor that must be considered is the significant economic rent captured by NGC in the midstream and ultimately distributed back to GORTT as a dividend. If the wholesale margin was passed back to upstream then GORTT would have to share the upside with the upstream suppliers as per the terms of the various upstream agreements. With this in mind, Poten's view is that the uncertain benefits associated with a significant restructuring of NGC's role as wholesaler / transporter are unlikely to be justified by the potential reduction in GORTT take, the challenges associated with maintaining existing GORTT take levels under a new structure (e.g. by imposing new taxes), and the time and cost associated with implementing what would undoubtedly be a major restructuring exercise. As such we do not believe that allowing the bypass of NGC, unbundling NGC's transportation activities, or fully liberalising the sector will be optimal routes for GORTT to follow.

Rather than maintaining the status quo, Poten's view is that, on expiry of the existing LNG contracts, NGC's wholesale role should be expanded to include ALNG, i.e. for new gas supply to ALNG NGC would buy gas from upstream and sell it to or toll it through ALNG. Although this is very much an interventionist approach, Poten's view is that this approach is likely to maximise GORTT's overall take from the sector in future, due to the significant economic rent that is captured by NGC in the midstream. This expanded role would not compromise the ability of the sector to provide more attractive prices to upstream in order to support new developments as NGC would be able to provide LNG-linked pricing to upstream suppliers if this was deemed necessary to support new upstream developments. It could also provide gas pricing to upstream linked to a basket of LNG, methanol and ammonia prices.

In addition, this option would allow NGC to manage gas supply to the whole downstream sector, whereas at the moment it has limited control of how much gas is supplied to LNG. This is of particular relevance in a gas shortfall situation

The volume risk that NGC is exposed to by any mismatches between its upstream supply and downstream sales contracts should be managed through industry standard performance provisions in place between NGC and both gas suppliers and buyers (as discussed in Sections 5 and 9) to avoid a continuation of the existing situation, e.g. inappropriate reliance on FM to manage volume shortfalls.

Poten's view is also that NGC's business should be refocused on its core wholesale & transportation activities, i.e. its other non-core assets should be divested, potentially either to other existing or new GORTT entities, or to new publicly-owned vehicles. There is no obvious reason as to why NGC is the best undertaker of its non-core roles, such as sector business development, or the best holder of its non-core assets, e.g. upstream production. In particular, these roles create potential conflicts of interest for NGC's core role.

NGC appears to have a history of reinvesting earnings for expansion of its commercial presence rather than dividending the revenue back to GORTT. Although this would be largely addressed by paring NGC back to its core activities, GORTT should ensure that NGC as a rule automatically dividends back surplus funds to GORTT. Extending NGC's wholesale role will also increase the oversight required of NGC's activities by GORTT to ensure that it is acting in the broadest interests of GORTT rather than its own more limited perspective.

In parallel with expanding NGC's wholesale role to include LNG, Poten recommends that the centrally-planned, allocative approach to future downstream gas contracting is adopted. For the same reasons put forward for the future role of NGC, Poten does not believe that adopting the market-based approach will be in the best interest of T&T. Under the two centrally-planned approaches there are clear attractions to the tendering option which would potentially provide a transparent and fair price discover process. However, our view is that the obstacles to implementing this option (establishing tender parameters between different commodity producers and between plants with different contract expiry dates) will be very difficult to overcome in practice. This leaves the approach under which GORTT determines the downstream consumers that will receive gas as the only viable option.

In terms of implementation, there will need to be an assessment made by GORTT/MEEA/NGC as to how much gas will be allocated to the key consuming sectors, e.g. LNG, ammonia, methanol and steel, as it is unlikely that there will be sufficient gas to fully satisfy demand. This analysis will rely on projections of expected future value to GORTT, which in turn will be highly dependent on projections of future commodity prices, which are inherently volatile and unpredictable. As such, although for example LNG may be projected to provide the highest value to T&T, GORTT may determine that it is in its interest to maintain a broader downstream portfolio in order to insulate itself from future global market changes, i.e. rather than fully filling LNG demand and shutting down various ammonia / methanol plants, GORTT may decide to reduce supply to LNG somewhat in order to maintain supply to ammonia / methanol.

Within the determination of how much gas to be supplied to each sector GORTT/MEEA/NGC will need to decide which plants should receive an allocation of gas and which, if necessary, should be shut down. While it will be a difficult decision to shut down a downstream plant, this will inevitably need to happen over time. If, for example, there is only sufficient gas to keep 50% of T&T's methanol capacity operational it will be far better from an economic perspective to shut down half of the plants and keep the remainder operating at full capacity, rather than keeping all of the plants running at half capacity but with full running costs. It should also be noted that although plants can be mothballed for a period of time and then brought back into operation if gas subsequently becomes available, in practice it will be costly to maintain plants in a mothballed state, keep staff etc. In an increasingly gas-short environment it is difficult to envisage any downstream plant in T&T restarting after it has been shut down for a prolonged period due to a lack of gas supply.

Based on NGC's contracted upstream gas supply, an assessment will also need to be made for how long NGC can provide downstream gas allocations. Although all of the downstream plants in question will have been fully amortised by the time that their existing gas supply contracts expire, buyers will need some certainty over future gas supply if they are to make investments which may be needed to prolong the life of the plant.

With its expanded wholesale role, experience of managing its existing downstream sales portfolio and share of GORTT's overall gas sector knowledge and expertise, NGC should be well-placed to provide the necessary analysis and recommendations to GORTT/MEEA on downstream gas allocations. However, there should be strict guidelines in place about how allocations should be made, i.e. maximising GORTT take from its gas resources, and GORTT/MEEA should have the ultimate decision-making power regarding any new gas allocations. GORTT/MEEA/NGC will also need to consider the potential allocation of gas to any new industries in parallel with its analysis of allocations to existing users. A potential framework for evaluating new projects against existing projects is discussed later in this section.

In summary, Poten's view is that NGC should:

- Continue to act as the monopoly buyer of gas from upstream, gas transporter and wholesale supplier of gas to the methanol and ammonia industries.
- Expand this role to include gas supply to LNG on expiry of the existing gas supply/LNG sales contracts.
- Be forced to divest its non-core assets, e.g. upstream production.
- Be forced to automatically dividend back surplus funds to GORTT.
- Provide the necessary analysis and recommendations to GORTT/MEEA on future downstream gas allocations, with GORTT/MEEA making any final decisions.

12.5.3 LNG

As discussed above, Poten's view is that post-expiry of the existing contracts any future gas supply should be routed through NGC to provide an efficient route for GORTT to maximise its take from the LNG value chain.

In terms of liquefaction model, GORTT's aims should be achievable without altering the existing merchant structure, i.e. minimising the take captured by the plant. It would need to be mandated by GORTT that the plant would only keep a (largely) fixed fee for providing liquefaction services, i.e. in practice a quasi-tolling structure, replicating the existing model for Trains 2/3, with the remainder of the LNG revenues passed back to NGC as the gas supplier. The fixed fee should be set at a reasonable level to provide a return to the Train 1 shareholders and cover their costs, taking into account that the asset has been fully amortised over the initial 20-year operational period.

In terms of LNG marketing, Poten's view is that continuing with the negotiated contracts model is unlikely to provide the best value for T&T; it risks replicating the existing issues of out of the market price and offshore value capture. For the same reasons our view is that utilising a marketing entity is not likely to be an optimal approach.

Tendering is a transparent and competitive process which ensures that the best price is realised for sales over the period that is covered by the tender. It is also is gaining increasing traction in the LNG business as the number of market players, shipping / regasification availability, and overall liquidity increases. As such, Poten's view is that this is the route that T&T should follow for future LNG sales to avoid the issues under the existing arrangements.

Without having access to the Train 1 contracts / agreements, Poten cannot comment on how a tendering process could be imposed on the owners of Train 1. The incumbent players will resist any changes to the status quo in the structuring of the LNG chain as it has proven very lucrative for many of them over recent years, if not for T&T.

In terms of implementing a tender process itself, NGC (via its TTLNG subsidiary) has already accumulated substantial experience of short-term LNG sales via its Train 4 offtake. It should be relatively straightforward for NGC to utilise this expertise to oversee any future tendering process for sales from ALNG. Again, there would need to be guidelines in place to manage this, under the ultimate oversight of GORTT/MEEA.

13.1 NEW GAS-BASED PROJECTS EVALUATION FRAMEWORK

13.1.1 Introduction

A gas-based industry evaluation framework should, fundamentally, provide a means with which to quantitatively evaluate the economic value that can be secured by the country through the development of a project or range of group of related projects. This allows the projects to be compared on a like-for-like basis and the country to select those that provide the most benefit for the volume of gas resource consumed. This analysis should include the range of economic benefits accrued; the value that the country receives for the gas sold as well as any royalties, duties and taxes paid the project. The output of the quantitative analysis should allow the range of options to be ranked according to benefits.

In addition to the quantitative evaluation it will also be necessary to consider some more qualitative aspects of a given project package, such as downstream added value, local employment and ownership etc.

13.1.2 Approach

13.1.2.1 Quantitative Assessment

Any natural gas project evaluation framework is necessary built around the current and projected supply and demand balance over the medium and long term. From this evaluation comes the available volume of gas for new projects and establishes the economic price of gas. The cost of gas production, which sets the floor price of any particular stream of gas supply, is established through analysis of the upstream production economics.

Having established the availability and economic threshold of the gas supply at particular price levels the next step is to evaluate proposed new projects to determine the expected economic value delivered to T&T, both against other new projects and against existing projects. This will requires projecting end market prices and shipping costs for export-orientated projects, developing capital and operating costs and developing discounted cashflow models. The model will be able to calculate the expected GORTT take from the plant as well as the expected netback gas pricing to NGC based on the gas pricing metrics being discussed for the project and the projected commodity prices. NGC expected net wholesale margin at these projected sales prices as well as estimated GORTT upstream take from the value chain will need to be included in the analysis.

Having established the base case comparative economics and GORTT take, it will then be necessary to undertake a sensitivity analysis to determine the sensitivity of the analysis to various assumptions, e.g. increases in capital and operating costs, commodity prices etc.

The analysis between existing and new projects will inevitably be complicated by the period of gas supply required. Existing plants could potentially accept gas allocations for a relatively short period, e.g. 1-2 years, while new plants will require a guaranteed supply for 15-20 years to justify investment. In a gas-short environment this will make it difficult for new projects to compete with existing plants.

13.1.2.2 Qualitative Evaluation & Ranking

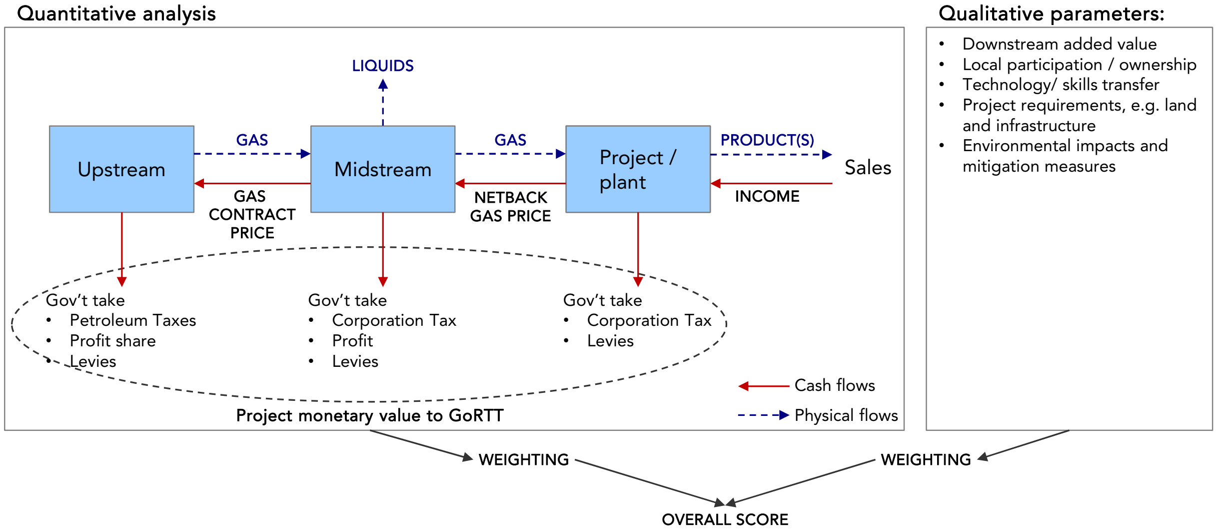
In addition to the quantitative evaluation it will also be necessary to consider some more qualitative aspects of a given project, such as:

- The potential for downstream added value.
- The potential for local ownership and financing.
- Local employment.
- Potential for technology transfer.
- Project requirements for raw materials, utilities and land.
- The level of local participation / ownership.
- Any potential environmental impacts and mitigation measures.

These parameters can be evaluated by attributing some form of scoring system and weighting the parameters by deemed importance / match with policy objectives.

The quantitative and qualitative aspects would then be brought together to provide an overall assessment, of which the quantitative element should achieve the major weighting.

Figure 13-1 Project Evaluation



The government take should be calculated on a levelised basis, i.e. the NPV of the tax cash flows divided by the NPV of gas consumption, and expressed in \$/Mcf or \$/MMBtu.

13.1.2.3 Ranking

The objective measure for ranking all projects/plants and sanctioning new gas plants should be that they provide a higher value for the gas than can be secured from the alternate existing options, and the **determination of value should be the cash paid to GORTT, primarily from taxes, as well as permanent jobs created and other qualitative parameters**. The quantitative and qualitative aspects are brought together to provide an overall assessment, of which the quantitative element should achieve the major weighting (Figure 13-1). The projects would be ranked in order of their overall scores. A worked example is shown in Table 13-1.

Table 13-1 Overall Assessment – Hypothetical Worked Example

	Quantitative analysis	Qualitative assessment				
	Government take ($/MMBtu)	Local employment	Local ownership	Requirements for materials, land, infrastructure, utilities	Technology transfer	Environmental impact and mitigation
Weighting	N/A	10	5	10	5	10
Maximum*	2.50	10	10	10	10	10
Score	2.00	8	4	8	2	7
Evaluation:	**Financial**	**Qualitative**				
Score	80	65				
Weighting	80	20				
Overall score	77					

* Maximum score for each parameter. The maximum government take would be the highest of the projects under evaluation.

13.1.3 Specifics for Assessing New Projects in T&T

There is a fundamental change in perspective required for the new project development planning process as the country moves into a time of gas shortfall. The present system was developed in a time of plentiful gas and is designed to evaluate new projects on the value brought to T&T in terms of financial benefits, employment, local content etc. Going forward as the gas sector move into a period of relative scarcity, with existing plants already supplied below contract levels, consideration must also be given to the consequences of making gas available to new projects.

The only way to provide gas supply for a new project that will be seeking a minimum of 15 years supply will be to effectively turn off supply to existing projects. The economics of closing off an existing plant that will essentially be running on cash costs will have to be closely studied and compared to a new plant, which will have significant capital costs to recover. The amortisation of debt in a new project, which will take place through most of the first decade of operations, will have the effect of reducing the tax take. Although an old plant may consume more gas than a new one per tonne of product, it may well be able to provide a higher value to T&T as it has no capital charges and will pay more tax.

Nevertheless, the energy consumption of existing plants is clearly an important issue. For plants seeking new gas supply this should be encouraged both through competition for supply and for plants with existing supply it may be necessary/advantageous to provide incentives for energy efficiency programmes which reduce gas consumption. Clearly any such programme will need to be structured so that it provides net positive benefit to T&T.

The selection of new locations for any new projects should be carefully considered in the light of a depleting gas supply. For any gas-based industrial site it is likely that much of the infrastructure will end up as redundant once the gas has depleted. Developing infrastructure at a new location will utilise capital that may not realise an adequate return, certainly in comparison to expanding capacity at existing facilities. Global best practice is to build in petrochemical industries in clusters to take advantage of synergies between industries, to be able to move product/feedstock over the fence and to gain the economic benefits of infrastructure and service sharing, e.g. port infrastructures and services, emergency services. This has been done in numerous locations around the world, Al Jubail and Yanbu in Saudi Arabia, Messaid in Qatar, Jurong Island in Singapore, Rayong in Thailand. T&T already has a cluster in Point Lisas with existing infrastructure and there is more than adequate land available for new industries. (A new plant in Point Lisas would not add to the logistics burden of the port or roads etc. as an existing plant would have to be turned off to provide the gas.)

The objective measure for sanctioning new gas plants should be that they provide a higher value for the gas than can be secured from the alternate existing options, and the determination of value should be netback prices and taxes paid to GORTT as well as the qualitative measures detailed above. As a matter of principle GORTT should not be offering tax holidays or any other fiscal benefits to gas-based projects, when there are existing projects short of gas supply.

13.2 DEVELOPMENT OF DOWNSTREAM DERIVATIVES

T&T has a very successful natural gas-based petrochemicals industry, producing ammonia and methanol to supply global markets. There is the potential for additional value creation through diversification downstream along the petrochemicals derivative chains for the existing products (ammonia and methanol). There is also scope to diversify across the ethylene and propylene value chains through methanol-to-olefins (MTO), steam cracking or propane dehydrogenation (PDH) routes.

While there is no doubt that diversification downstream can create added value for the country, there are obstacles in the way. Not least is the absence of a local market to absorb downstream production. To be competitive, any downstream derivative will require the economies of scale from a world-scale production facility, which will require production to be exported. Secondary and tertiary derivatives of the main petrochemicals generally have more numerous and smaller consumers than primary bulk chemicals, which means that transportation costs generally constitute a larger proportion of final delivered costs. Hence, these derivatives are usually produced close to final markets unless there is a compelling competitive advantage for producing at the same site as the primary chemical.

13.2.1 Expansion Downstream from Ammonia and Methanol

There has been limited expansion downstream in the ammonia chain in T&T. Urea is produced by PCS, while urea, urea ammonium nitrate solution and melamine are produced in the AUM complex (owned by MHTL). Urea is a particular example of where there is a compelling reason for conversion of the primary chemical (ammonia) to the secondary derivative (urea) due to the benefits of the integration of the two processes (carbon dioxide recycle), and urea is generally produced at the same site as ammonia. There is further scope for producing urea from ammonia, as most of T&T's ammonia production is exported.

There is currently no large-scale production of methanol derivatives in T&T. There appears to be little economic benefit in producing the largest methanol derivative in T&T relative to exporting methanol as the production facilities and process are simple, creating little in terms of added value such as employment for the economy. However, acetic acid production from methanol may be feasible as the carbon monoxide feedstock required for the process may be economically feasible to produce.

13.2.2 Expansion into New Petrochemicals (Olefins & Derivatives, GTL)

There is currently no production of olefins and derivatives in T&T. Many routes to olefins production have been commercialised. Three in particular are of interest considering T&T's potential availability of the precursor feedstock: steam cracking of LPGs, PDH and MTO. The economics of the olefin chain depend on a competitive advantage and economy of scale in derivatives production, which does not lend itself to T&T's position.

The use of LPG as a feedstock for steam cracking or PDH could be feasible given the relatively low price/value of propane and butane. However, the volumes of feedstock available are barely sufficient for world-scale production facilities. Methanol-to-olefins is a recently-commercialised route to olefins production which is extremely capital intensive and relies on economies of scale and competitive edge including a local market for the products in downstream olefins chain.

Production of gas-to-liquids (GTL) via the Fischer-Tropsch process is highly capital intensive. The economics of the process require low cost gas and high prices for the liquid products, gasoil and naphtha. Given the situation regarding gas availability and expected low netback prices of natural gas, GTL is not an economically attractive use of T&T's resource.

13.3 THE ROLE OF NATIONAL ENERGY IN FACILITATING DEVELOPMENT

13.3.1 Overview

The National Energy Corporation (NEC) is a wholly owned subsidiary of NGC, and was incorporated in 1979. The company evolved from work first started by the Coordinating Task Force to monetise the country's natural gas resources, as well as developing and managing industrial and marine infrastructure. The company was involved in the construction and operation of the early petrochemical plants and the port and marine infrastructure which services all the plants at the Point Lisas Industrial Estate. In 1999, NEC became an independent entity within the NGC group of companies, with a mandate to "develop and manage suitable infrastructure, in order to facilitate and promote the various activities relevant and appropriate to natural gas- related operations. In 2004 NEC's mandate was further expanded to include the facilitation and promotion of natural gas based development.

The company is taking a proactive approach to promoting T&T's energy brand regionally and internationally, as well as continuing to execute the development of energy projects and infrastructure under the guidance of MEEA. In 2013 a rebranding exercise was undertaken to transition from National Energy Corporation to National Energy.

13.3.2 Role of National Energy

The company's core business is the conceptualisation, promotion, development and facilitation of new energy based and downstream industries in T&T, which includes:

- Identification and development of new industrial estates and associated deepwater ports.
- Ownership and operation of marine and other infrastructural assets to facilitate gas based metals plants.
- Towage and harbour operations.
- Development and management of La Brea and Union Industrial estates.
- Sustainable management of the environment.

The company is the primary body in the energy sector for industrial promotion. National Energy is the primary interface for new industrial investors to T&T, and it is the role of the company to act as a "one stop shop" facilitating the interaction of the investor with the various stakeholders, and ultimately making a recommendation to MEEA on the suitability of the project. National Energy's focus areas for industrial development are as follows:

- LNG – mid scale and small scale.
- Petrochemicals – ammonia, methanol, ethane/propane processing.
- Inorganics.
- Plastics – methanol to polyolefins.
- Energy based manufacturing.
- Bio-chemicals and speciality products – single cell protein production.
- Metals – steel processing, silico-manganese refining.
- Renewables.

13.3.3 National Energy Evaluation Process

The company has a four stage process of initiation, evaluation, validation and implementation of projects, with gates at the end of each process.

Table 13-2 National Energy Project Development Process
(Source; National Energy)

	Initiation	Evaluation	Validation	Implementation
Input	Criteria[1]	Approval to proceed	Approval to proceed	Approved charter
Process	Identify and conceptualise	Study	Prove	Plan
Output	Preliminary Screening Report	Pre-feasibility Report Project selection MOU outline	Feasibility Report	Preparation for implementation

The project proposals required by National Energy from investors are comprehensive, and consist of the following elements:

- Introduction and overview of project.
- Process & technology details and description.
- Products (quantities, and target markets, any offtake agreements identified.
- Investment partners and structure of project.
- Timeline for project development, plant construction and production.
- Economics, cashflow projections, and analysis (at least 10 years) including ROI expectations.
- Estimated capital expenditure.
- Benefits to T&T, for example:
  - Downstream processing, local added value.
  - Potential for local ownership and financing.
  - Employment of locals.
  - Cooperation with local universities /technology transfer.
- Project requirements for raw materials, utilities and land e.g. natural gas, water, electricity, land acreage.
- Extent of local participation / ownership.
- Brief indication of environmental impacts and mitigation measures.
- Brief statement on energy efficiency measures, if any.
- Future plans for expansion.
- Any other issues relevant to the proposal.

[1] Present criteria and projects which go beyond first derivative and support sustainable downstream industries

All major projects go to Cabinet for approval. The criteria used by Cabinet in their evaluation are as follows:

- Degree of value added.
- Environmental impact.
- Capital expenditure.
- Degree of local content.
- Extent of variation with gas price.
- Early construction plan.
- Energy efficiency.
- Local content in operations and construction.
- Variation in terms of conditions power.
- Variation on estate and pier rates.
- Additional benefits.

The evaluation framework process that has been developed to evaluate project appears rigorous and appropriate.

The role of National Energy as a one stop shop is a best-practice approach to industrial development. This is the approach which is followed in other industrial development sites such as Ras Laffan in Qatar, Jubail and Yanbu in Saudi Arabia and Jurong Island in Singapore.

13.3.4 Role of NEC Going Forward

NEC has a significant and valuable role to play in the future in a number of different areas. Although there will clearly be limited scope for promoting incremental gas projects given the depleting gas reserves there is some scope for value addition utilising the products already available in the country. There is also an important role in in encouraging energy efficiency in the gas sector and in promoting the use of renewable energy. Every kWh of power that is supplied by renewable energy will allow additional gas to be provided to downstream industries and LNG instead of consuming it in power generation.

The expertise that NEC has developed over the last several decades could be profitably put to use overseas in countries which are presently at the early stages of gas development, such as Surinam and Guyana. This is the ultimate development of local content; the export of skills and expertise.

13.4 COMPETITIVNESS OF T&T – INDUSTRY PERCEPTIONS

In developing policies and implementation plans MEEA should be cognisant of the perceptions of existing upstream and players and industry groups in the industry, as this will help to appropriately shape the message that GORTT wishes to give out. As part of the Master Planning process a survey was taken out to elicit the views of a cohort of industry participants over a range of issues.

13.4.1 Business Survey

As part of the GMP activities Poten conducted a series of interviews with executives from a range of gas-producing and downstream gas companies and from the Energy Chamber of T&T. The interviews aimed to determine interviewees' views on the competitiveness and desirability of doing business in T&T. Each interview took the form of a wide-ranging discussion of the issues faced by companies in T&T, including specific topics and questions as shown in Table 13-3.

Table 13-3 Business Survey - Questionnaire

Subject	Questions
Upstream	How competitive is the fiscal regime of T&T? (What in your view needs to change?) How easy is it to develop projects in T&T compared to other countries?
Midstream	How easy or difficult is to deal with NGC compared with indigenous utilities elsewhere?
Ease of doing business	GORTT bureaucracy? Ability to import goods? Tendering for services – local content requirements?
Governance	Clarity of GORTT policy? Continuity of GORTT policy? Ease of interaction with MEEA?
Regulation	Environmental compliance and monitoring?
Financial	Costs of goods and services?
Fiscal	Level of profit taxes and duties? Import duties? Audit and tax filing requirements? Fiscal incentives?
Services	Availability and quality of local service provision – maintenance, fabrication, inspection etc.? Cost of local services? Port services? Customs – are they adequate/fit for purpose?

The discussion below highlights the most important aspects of the interviewees' responses.

13.4.1.1 PSC Terms

Fiscal terms are judged currently to be competitive (i.e., close to the maximum that companies are willing to bear), but GORTT will in future need to take account of the challenges that companies face in developing small pools of gas and the relatively untested deepwater blocks. GORTT has shown itself in recent years to be pragmatic over tailoring terms to meet the minimum investment requirements of upstream companies on a project by project basis.

13.4.1.2 Gas Supply

The main issue with respect to gas supply is simply the shortage of gas, which is a well-known problem, but which is obviously critical for downstream companies to operate profitably. Existing plants face operational difficulties when supplies are variable/intermittent. Another issue raised was the quality of gas delivered when PPGPL is offline, e.g. for annual maintenance, and the gas as a result contains significant quantities of liquids, which causes operational problems at downstream plants.

13.4.1.3 NGC

NGC fulfils several roles, as regulator, gas purchaser, aggregator, monopoly seller, investor, policy advisor, etc. Decision-making is inevitably not transparent, being difficult to dissociate regulatory from commercial decisions. The suggestion is that gas sector regulation at least should be split off into a separate, independent body or that upstream and downstream activities are separated from the midstream roles in order to avoid conflicts of interest.

13.4.1.4 Institutional Capacity

Several interviewees referred to problems faced by GORTT bodies and agencies and with NGC in terms of their institutional capacity, in particular a lack of resources in GORTT. This is despite GORTT being the country's largest employer, employing some 40 % of the total workforce. The problem is manifested in various different ways – delays in processing permits and making decisions, lack of effective monitoring and policing of emissions, etc.

The GORTT organisations impacting on the energy sector are principally MEEA, NGC, Petrotrin and EMA. These organisations work well on a personal level, i.e. with specific relationships, but otherwise are rather bureaucratic. Most processes are still paper-based, and interviewees would like to see quicker move to online systems (the Single Electronic Window launched in 2012 as a gateway for business interaction with GORTT agencies was seen as a positive development).

A possible solution would be to second staff from upstream and downstream companies in the energy sector for periods of 2-3 years to boost the numbers of qualified personnel in the organisations mentioned. This could help them to improve their internal organisation, procedures and systems as well as carrying out their roles more effectively. bpTT has expressed willingness to participate in such a scheme with MEEA.

Political appointments to agencies and GORTT-owned companies inevitably frustrate the continuity of operation of the agencies and companies concerned as new appointees take time to learn the business and impose their own political agendas. Agencies and companies should ideally be headed by professional staff with relevant technical and business expertise operating under official policies set by GORTT.

13.4.1.5 Government

A general comment, particularly in relation to the upstream, is that GORTT policy is not clear; the greatest clarity appearing in election manifestos. There were mixed views as to the continuity of policy between governments. The current Gas Master Plan will provide recommendations that will help GORTT to frame its energy policy for the next ten or more years.

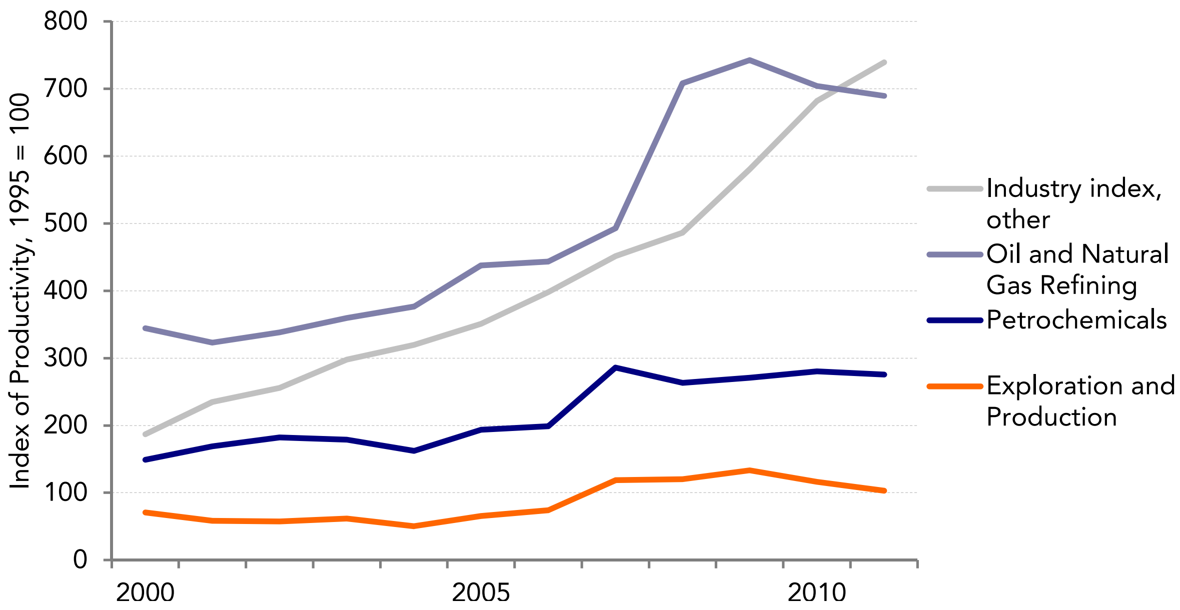
Interviewees have found it difficult to resolve problems with the Board of Inland Revenue (BIR). Problems that drag on, and which often end up in court, increase the cost of doing business. High interest on unpaid tax (20%) creates a perverse incentive for BIR to delay resolution of disputes/issues.

13.4.1.6 Productivity

Concern was expressed that productivity levels in the energy sector are falling and wages increasing. Overall, the World Economic Forum's 2014-15 Global Competitiveness Report scored T&T's pay and productivity as 3.28 out of 7, ranking 124 out of 151 economies.

Central Statistical Office (part of the MPSD) statistics published in 2014 show that productivity in the oil & gas and petrochemical sectors has stabilised or fallen since 2007[2] (Figure 13-2). In the case of exploration and production, productivity is only marginally higher than in 1995. By contrast, the chart emphasises how productivity growth in the rest of the economy, which has grown consistently year on year since 1995 when the index started (CAGR 13.3%/y), leads that in the exploration and production (CAGR 0.2%/y) and petrochemicals industries (CAGR 6.5%/y).

Figure 13-2 Index of Productivity - All Employees
(source: CSO. Base Period: Average of 4 Quarters 1995 = 100)



T&T generally has good local services although, unsurprisingly, availability can be an issue at peak times. GORTT could do more to sponsor skills training programmes to overcome skills shortages in specific areas, and should consult with industry to determine what is required. A business association for the

[2] *Index of Domestic Productivity*, CSO 2014: Index of Productivity – All employees.

offshore sector – exploration and production and services – similar to the UK's Offshore Operators' Association could be helpful for the coordination of services for day to day operations as well as turnaround maintenance.

Section 14 Institutional: Policy, Regulation & Legislation

14.1 INSTITUTIONAL & REGULATORY ARRANGEMENTS

14.1.1 Introduction

The institutional and regulatory framework for the natural gas subsector is an amalgamation of policies and principles taken from contract, property, administrative and competition law. International legal concepts can be involved as well, particularly in the area of cross-border unitisation and joint development of gas fields. Multilateral treaties and international conventions, such as those adopted to regulate cross-border pipelines, control marine pollution and reduce carbon dioxide emissions, are of increasing importance.

The regulatory framework created to address the technical and commercial characteristics of the natural gas industry in a particular country is unique. Governments are constantly balancing whether to emphasise security of supply or market competition. Most often, the gas resource is owned by the host government. The right to explore for and produce involves agreements directly with sovereign states resembling "private treaties" for which regulatory and commercial roles often become intertwined. The lack of downstream competition in processing and transportation also means that some form of governmental intervention (state-owned enterprises, licenses, regulations, and taxes) must also be incorporated into the institutional and regulatory framework.

The energy sector is the mainstay of the economy for T&T. According to the Central Bank of T&T, over the last five years the energy sector has contributed on average 44% of GDP, 46% of GORTT revenue, and 85% of export earnings. Since 1997 natural gas production has exceeded that of crude oil. The significance of revenue from the natural gas subsector to GORTT's budget adds further emphasis to the preparation of a natural gas master plan.

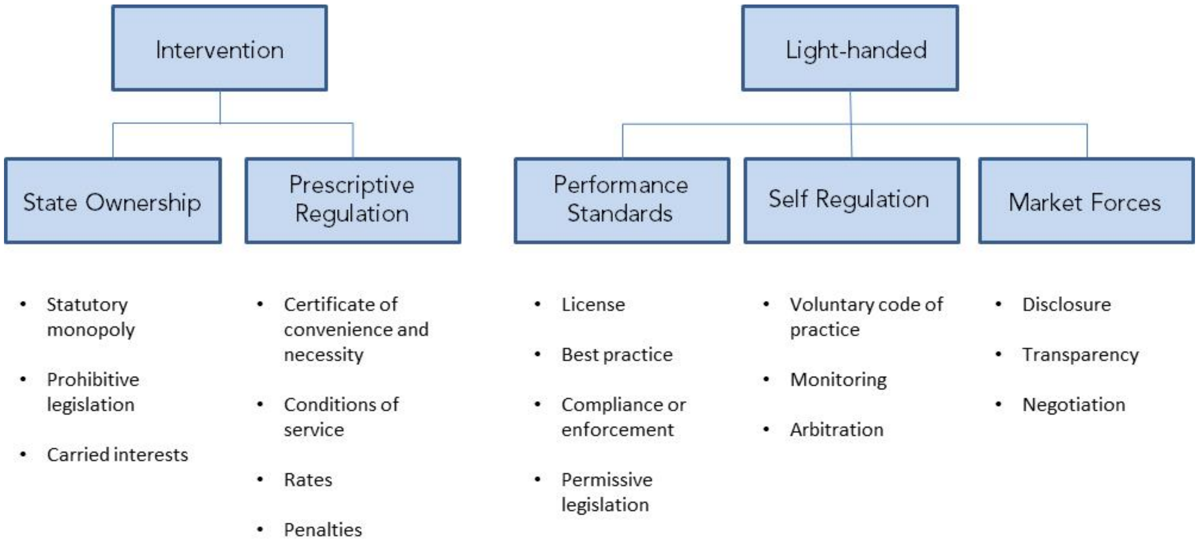
However, GORTT lacks an effective institutional and regulatory framework for administering the natural gas subsector. The main piece of legislation was adopted in 1962 to regulate the exploration and production of crude oil. Technical licensing regulations have been adopted for natural gas facilities, but no oversight is applied to commercial monopolies and supply obligations. Information on the amount of revenue derived from the natural gas subsector is not separately accounted for.

In the context of a natural gas master plan, the purpose of the institutional and regulatory framework is to 'operationalise' policies for achieving the goals identified in the planning process. In some respects this review would follow the completion of a master plan. However, an early review serves to identify potential institutional and regulatory impediments to achieving the goals set by the master plan.

14.1.2 Institutional Structure

The extent of a specific institutional and regulatory framework for its natural gas industry depends upon the policy being pursued by a government. As shown in Figure 14-1, the policy options range from interventionist to light-handed.

Figure 14-1 Natural Gas Industry Regulation



The various legislative and regulatory measures for implementing an adopted policy are described in Appendix K.

14.1.3 Regulation

GORTT is both the regulator and holds a major commercial interest in the natural gas subsector. Despite the potential for conflicting roles, the country is well-regarded as a location for foreign direct investment. Additionally, in order to ensure transparency, GORTT subscribes to the Extractive Industries Transparency Initiative (EITI). The Cabinet delegated responsibility for achieving compliance with EITI guidelines to MEEA. T&T became a compliant country on 23rd January 2015.

MEEA is the principle regulatory authority for the natural gas subsector. In this capacity, MEEA administers the bidding process for PSCs, and compliance with the licenses issued for conducting petroleum operations. The Local Content & Local Participation Policy was adopted in 2004, with implementation overseen by the Permanent Local Content Committee within MEEA. MEEA also provides the technical support to the Ministry of Foreign Affairs for cross-border unitisations.

Other governmental institutions such as the Ministry of Finance and Economy (MOFE) and Central Bank of T&T are involved in terms of taxation and finance. In 2007 GORTT adopted legislation to establish the Heritage and Stabilization Fund (HSF). Revenue from petroleum production can either be withdrawn from or transferred into the Consolidated Fund depending upon whether the amount is either 10% above, or below forecasts made by MOFE, as discussed in Section 17.

Health, safety and environmental protection are a critical part of industry operations. The Environmental Management Authority issues certificates of clearance for new projects and designates environmentally sensitive areas and species. Policy, regulations and codes of practice for work place safety in the petroleum industry are administered by the Occupational Health and Safety Authority/Agency.

GORTT has been successful in pursuing a strategy where the State is both the regulator and a commercial participant in the natural gas subsector. This has meant that GORTT has adopted a relatively interventionist policy towards the natural gas subsector at a time when other countries and markets have been liberalising their gas sectors by separating the sale of gas from processing and transportation services.

14.1.4 Legislation & Regulations

Petroleum resources in T&T are both privately and publicly owned. Original grants of the fee simple title included all subsurface rights not expressly reserved to GORTT. This created split estates, where fee simple owners have transferred the surface rights while retaining their mineral rights. Private mining leases are granted by the owner of the mineral estate.

Under Section 1(2) of the 1976 Constitution the seabed, subsoil, territorial seas and continental shelf are part of the sovereign territory of T&T. As a result, GORTT owns petroleum resources on State Lands, all offshore areas, and some private lands where the sub-surface rights have been reserved to the State.

14.1.4.1 Upstream

The upstream portion of T&T's petroleum industry is regulated under a framework composed of the Petroleum Act, ('Act') and the Petroleum Regulations, (Regulations). The Act was adopted in 1962, with minor amendments made to incorporate the use of PSCs. Petroleum operations are broadly defined, as activities to explore for and develop privately and publicly owned petroleum resources. The Act and Regulations are further supplemented by EPLs and PSCs. This scheme applies equally to petroleum operations that are conducted onshore and offshore.

Under Section 3 of the Act, the President exercises public rights of ownership in land and petroleum resources on behalf of the State and is a party to PSCs and related EPLs. Under Section 6(3), the Minister has the discretion to either grant EPLs, or enter into PSCs. If a PSC is employed as the granting instrument, it is possible to contract-out of the Act and Regulations.

The Act was revised by the addition of Sections 6(3) and 6(4) when PSCs replaced EPLs as the method for granting exploration rights. Section 6(4) allows the Minister to enter into PSCs that exclude or modify the application of the Act and Regulations. While the exercise of this provision would enhance contract stability, it allows the terms and conditions of the PSC to supplant the regulatory scheme established by the Parliament. It also means that each PSC must be carefully reviewed to determine the extent that the terms of the agreement have modified the Act and Regulations. Rather than modify the Act to address changes in circumstances, the practice has been to revise the terms and conditions of the Model PSCs that are used for each bidding round.

The current policy is for PSCs to be awarded on the basis of competitive bidding rounds. In some situations, PSCs have sometimes been awarded by the Minister 'out of round'. This option is used where there has been a bid for a block that was not accepted by MEEA due to the bid not meeting the minimum benchmark. In which case, the bidder is invited to submit a revised bid out of round. In some situations the decision to award the area is based on the financial capacity and operational experience of a company, rather than fiscal terms of the bid.

14.1.4.2 Midstream and Downstream

The broad definition of 'petroleum operations' brings midstream and downstream sectors within the scope of the Act and Regulations. Rather than adopting a separate Gas Act, the Regulations have extended to the Midstream and Downstream segments. The licensing scheme in Section 6 of the Act has been extended to include:

- Refining;
- Pipelines;
- Marketing;
- Petrochemicals,
- Liquefaction of Natural Gas;
- Transportation (other than by pipeline); and
- Compressed Natural Gas Licenses.

MEEA has developed standard form licenses for each type of facility. However, as petrochemical facilities have been developed under project agreements between the sponsor and GORTT, no license has been issued for these facilities.

Licensees are able to exercise ‘ancillary rights’ in order to secure plant sites, rights of way and water supply. If the ancillary rights cannot be secured through negotiation, their use can be declared to be for public purpose, and can be taken under a Compulsory Order issued by the Minister. The Minister can declare pipelines constructed under Order to be common carriers. Pipelines that are not constructed under Order are obliged to negotiate with third-parties for the use of excess capacity. If agreement cannot be reached by the parties, the Minister can issue an Order setting the conditions of access.

Neither the Act nor the Regulations address other issues that are relevant to the natural gas subsector, such as approval of sales contracts, access to facilities, quality specifications, interruption or curtailment of supply, or pricing methodology. In T&T, economic regulation of natural gas is addressed by contract rather than regulation. The Minister’s role in gas marketing is contained in the gas development provisions in the PSC. Under Section 16.5(c), the Minister approves the marketing arrangements, pricing, and whether the gas is to be exported.

Interruption of supply has become the focus of attention. NGC has invoked Force Majeure in response to the shortfall in delivery to its downstream customers. This situation raises issues under the gas supply agreements with NGC, as well as the project investment agreements between the sponsors and GORTT.

As discussed elsewhere in this report, the adoption of one or more of the following options should be considered by GORTT as means for dealing with shortfalls in supply:

- Ensuring enforceable commitments in upstream supply contracts to NGC, e.g. compensation for non-delivery under ‘Send-or-Pay’.
- A clear process and criteria for evaluating market development plans submitted under a PSC.

Although it has not been used, Section 36 of the Act gives the President broad authority to preempt the conditions of existing licenses and order expansion of production during time of national emergency. This authority cannot be used lightly. Such intervention runs counter to the purpose of developing a Natural Gas Master Plan and the implementation of a strategy for ensuring that gas deliveries can be maintained. It would also damage the reputation of T&T as a desirable location for foreign investment.

14.1.4.3 Cross-Border Unitisation & Joint Development

T&T’s relationship with neighbouring Venezuela is an important consideration for future natural gas development, as discussed in Sections 7 and 8.

On 20 March 2007, instruments of ratification were exchanged for the Framework Treaty on the Unitisation of Hydrocarbon Reservoirs that extend across the Delimitation Line between T&T and the Bolivarian Republic of Venezuela. The Agreement of Unitisation of the Exploitation and Development of Hydrocarbon Reservoirs for the Loran Manatee Field was signed on 16 August 2010. Allocation of reserves was done on the basis of Original Gas In-Place (OGIP), with the provision for redetermination of reserves to be made at the request of either country. Once effective, the redetermination is to be applied retroactively. The Operating Agreement was approved in September 2013. Unit operations will be conducted under the following arrangement:

- Directing Committee – representatives of both Governments and the four operating companies involved.
- Investment Committee – four operating companies (PdVSA, Chevron Trinidad and Tobago, Chevron Global and BG).
- Executing Entity – to be chosen from among the four companies involved, which will submit a Development Plan for the consideration of the Ministerial Commission.

The four operating companies are in the process of negotiating a joint venture operating agreement (JVOA) for the management of the unit, which is to be submitted to the Directing Committee. The Development Plan is to be submitted within 90 days after the JVOA. While the field is to be developed as a single unit, each country will take its share in-kind of the gas produced from the field.

The two countries are also pursuing agreements on unitising the Kapok-Dorado and Manakin-Cocuina fields. The respective Ministers signed the Manakin-Cocuina Treaty on 24 February 2015. The final report of the Reservoir Technical Working Group (RTWG) for the Kapok-Dorado Field unitisation was submitted in 2008 and has been reconvened for consideration of additional well data.

14.1.5 Reforming the Institutional & Regulatory Framework

Recommendations for reforming the institutional and regulatory framework for the gas sector are divided between amendments to the Petroleum Act and other regulatory instruments, such as the Petroleum Regulations and the Petroleum Agreement. Minor changes have been made to the Petroleum Act since it was first enacted in 1969. However, a number of key features related to the development and use of natural gas are not reflected in this legislation. The main concerns with the Petroleum Act are as follows:

- There is no statement of purpose
- Negotiated terms of PSCs should not preempt the Petroleum Act and Regulations

Other institutional and regulatory changes to improve administration of the natural gas sector include:

- Adopting regulations to address the reliability of supply.
- Expanding the ability of the Minister to reconsider the joint marketing election for GORTT's share of natural gas under Annex D to the PSC.

The following sections discuss the recommendations for the points highlighted above.

14.1.5.1 Statement of Purpose

It is noticeable at the outset that the Petroleum Act does not contain a statement of purpose that reflects the policy of GORTT towards the development of its petroleum resources. This is in contrast to the following statement of policy adopted by MEEA in accordance with Section 7 of the Freedom of Information Act (FOIA):

> *The main policy goal for the energy sector is to optimally exploit the country's hydrocarbon resources ensuring its efficient administration in order to obtain the greatest returns to the country for the benefit of its citizens.*

As a general rule, modern petroleum laws contain a provision that sets out the purpose of legislation in terms of the goals and objectives of the government. The following are several examples of this approach:

(1) U.S. Interstate Oil & Gas Conservation Commission 2004 Model Oil and Gas Conservation Act

> *Declaration of Purpose*
>
> *Because of the economic and strategic importance of oil and gas, the prevention of waste of oil and gas, the promotion of oil and gas conservation, and the protection of correlative rights, public health, public safety, and the environment are declared to be in the public interest. Accordingly, the purpose of this Act is the prevention of waste, the promotion of conservation, and the protection of correlative rights, public health, public safety, and the environment.*

(2) Mexico Hydrocarbon Law Dated 29 April 2014

Article 2. The purpose of this Law is to regulate the Hydrocarbons Industry in National Territory, which covers:

> *I. Surface inspection and Exploration, and the Extraction and Exploration of Hydrocarbons*
>
> *II. The Treatment, refining, sale, commercialization, transportation and storage of Petroleum*
>
> *III. The processing, compression, liquefaction, regasification and decompression as well as the Transportation, Storage, Distribution, Retail Sale to the Public of natural gas*
>
> *IV. The Transportation, Storage, Distribution, Retail Sale to the Public of Liquefied Petroleum Gas*
>
> *V. The Transportation, Storage, Distribution, Retail Sale to the Public of Petroleum Products; and*
>
> *VI. Pipeline Transportation and Storage connected to pipelines of Petrochemicals.*

(3) The Regulation of the Petroleum Industry in Brazil Law No. 9478 of August 6, 1997

> *Chapter I On The Principle and Objectives of the National Energy Policy*
>
> *Art. 1 - The national policies for the rational utilization of the energy sources will aim at the following objectives: I - preserving the national interests; II - promoting development, the growth of the labor market, and the valuation of the energy resources; III - protecting the consumer interest, including in respect to price, quality and availability of products; IV - protecting the*

environment and promoting the conservation of energy; V - guaranteeing the supply of oil products throughout the national territory, pursuant the paragraph 2 of article 177 of the Constitution; VI - promoting the increase of natural gas use on an economic base; VII - identifying the most adequate solutions for the supply of electric energy in the various regions of the country; VIII - utilizing alternative energy sources through the economic use of available inputs, and applicable technologies; IX - promoting free competition; X - attracting investments in energy production; XI - promoting the growth of the country's competitiveness in the international market

(4) New Zealand Crown Minerals Act 1991

Purpose

(1) The purpose of this Act is to promote prospecting for, exploration for, and mining of Crown owned minerals for the benefit of New Zealand.

(2) To this end, this Act provides for—

(a) the efficient allocation of rights to prospect for, explore for, and mine Crown owned minerals; and

(b) the effective management and regulation of the exercise of those rights; and

(c) the carrying out, in accordance with good industry practice, of activities in respect of those rights; and

(d) a fair financial return to the Crown for its minerals.

(5) Philippines Oil Exploration and Development Act of 1972

SECTION 2. Declaration of policy. - It is hereby declared to be the policy of the State to hasten the discovery and production of indigenous petroleum through the utilization of government and/or private resources, local and foreign, under the arrangements embodied in this Act which are calculated to yield the maximum benefit to the Filipino people and the revenues to the Philippine Government for use in furtherance of national economic development, and to assure just returns to participating private enterprises, particularly those that will provide the necessary services, financing and technology and fully assume all exploration risks.

The inclusion of a statement of purpose in the Petroleum Act would provide a basis for the exercise of the discretion given to the Minister in other sections of the Act, as well as any delegation made to MEEA officials. Acting consistently with the declaration of purpose further shields the exercise of the Minister's discretion from challenge through judicial review. Under judicial review the court considers whether decisions were taken fairly, legally, rationally and reasonably. If they were not, the court may cancel the decision and send it back to the appropriate body for reconsideration.

The wording of the purpose clause should incorporate MEEA's statement of functions filed under the FOIA. It should also include adherence to 'good international oil and gas practice', maximum efficient recovery of hydrocarbon resources, promotion of opportunity for local businesses and protection of the environment. Many of these points are reference in Section 2.0 Policy Objectives and Intent of Guide in the Ministry's Technical Guidance Document - GD 06, for Approval of Development Plans.

14.1.5.2 Repeal Article 6(4)

It is contrary to the hierarchy of any legal system for a contract to be used as an instrument to oust a government from imposing its laws and regulations. However, Article 6(4) of the Petroleum Act has such an effect. This provision reads as follows:

> *(4) Where a production sharing contract is entered into under subsection (3), so much only of this Act and the Regulations as are not excluded by the contract shall apply to any person carrying on petroleum operations under such contract, and where any provision of this Act or the Regulations is modified by the contract for the purposes of such contract, this Act and the Regulations shall be read and construed accordingly, and where there is any conflict or variance with reference to any matter between the provisions of the contract and this Act or the Regulations, the provisions of the contract shall prevail.*

This subsection appears to have its origins in the dual nature of how exploration rights are granted in T&T. Prior to and following the enactment of the Petroleum Act, Exploration and Production Licenses were the main contractual instruments. With the rapid development of petroleum resources a more effective means of allocation was considered necessary, and in 1974 the first PSC was signed. Subsequently, the World Bank's Model PSC was adopted in 1995, as a parallel system to E&P Licenses. The current "Taxable PSC", incorporating both profit sharing and taxes as fiscal measures, was adopted in 2005. More recently, all terms of the PSC are regarded as biddable. As a result of this flexibility, contractors have an invitation to tailor their legal regime by 'contracting out' of the general legal framework.

The Petroleum Act was passed by the Parliament. The Petroleum Regulations were promulgated by the President and Scheduled to the Petroleum Act. It is fundamentally contrary to the legislative process of a country, where its representatives are democratically elected, to structure an arrangement whereby the Minister of the day and a contractor can agree to choose to be exempt under a bilateral agreement.

Concerns about changes in legislation and regulation are better addressed by the incorporation of a so-called 'Contract Stability' clause that allows the contractor to obtain cost recovery for increases in taxes or compliance costs. This is approach incorporated in other countries that have adopted the PSC approach. Otherwise, if changes in legislation are needed to accommodate concerns of investors, those issues should come before a parliamentary committee and be presented as legislation to amend the Petroleum Act. Where there are issues with the scope of regulation, they can be dealt with by submissions to the Minister, leading to action by the President in amending the regulations.

14.1.5.3 Reliable Supply Regulations

Under the Petroleum Act, the President is authorised to make regulations for the purposes listed in Section 29(1). Once they are issued, the Regulations are scheduled to the Act as Subsidiary Legislation. Petroleum Regulations were first adopted in 1974 and have been amended several times, most recently in 2012, and primarily establish a process for licensing activities in the petroleum sector. In regards to natural gas, the following licenses are subject to the Regulations:

1) Exploration License;

2) Exploration and Production Licence (Public & Private Petroleum Rights);

3) Liquefaction of Natural Gas License;

4) Pipeline License;

5) Marketing License in respect of wholesale operations;

6) Petrochemical License; and

7) Compressed Natural Gas License

Both Section 29 (2) of the Act and Section 23(1) of the Regulations provide that a license is to be issued on the terms and conditions as the Minister considers appropriate, subject to the provisions of the Act and Regulations.

The Act authorises the President to make such regulations as are considered necessary regarding the conditions to be observed by licensees. It is standard practice for a gas sector regulator to adopt rules regarding the reliability of supply. This includes a process for curtailment of deliveries when supply is interrupted. For example, in United Kingdom, the Secretary of State requested Ofgem in 2011 to assess the potential risk to medium and long-term gas security of supply and evaluate measures in the gas market to enhance the reliability of supply including an assessment of the:

1) Scale and nature of the risks to security of supply given developments in the global gas market;

2) Level of risk that remains after the proposed reform of emergency gas cash-out arrangements;

3) Range of potential measures to mitigate risks that remain; and

4) Relative merits of each of these measures, and how these measures might be designed and implemented.

Similar reviews have been conducted by the U.S. Federal Energy Regulatory Commission and the European Union. In 2010 the European Parliament adopted Regulation 994/2010 on Measures to Safeguard Security of Gas Supply.

Considering the potential for disruption in supply in T&T over the coming decade, it is recommended that additional Regulations be adopted to address the obligation of natural gas suppliers to demonstrate reliability as a condition of performance under their respective licenses. The main facets of the regulation would be:

1) An obligation to limit interruption to end-users for a fixed period;

2) A financial liability to end-users if the gas supplier exceeds the period;

3) Monitoring and reporting of the gas supplier's compliance;

4) Coordination with end-users for interruptions due to annual maintenance; and

5) Preparation of a curtailment program to be implemented in the event of the interruption gas supply due to an emergency or diminution of supply.

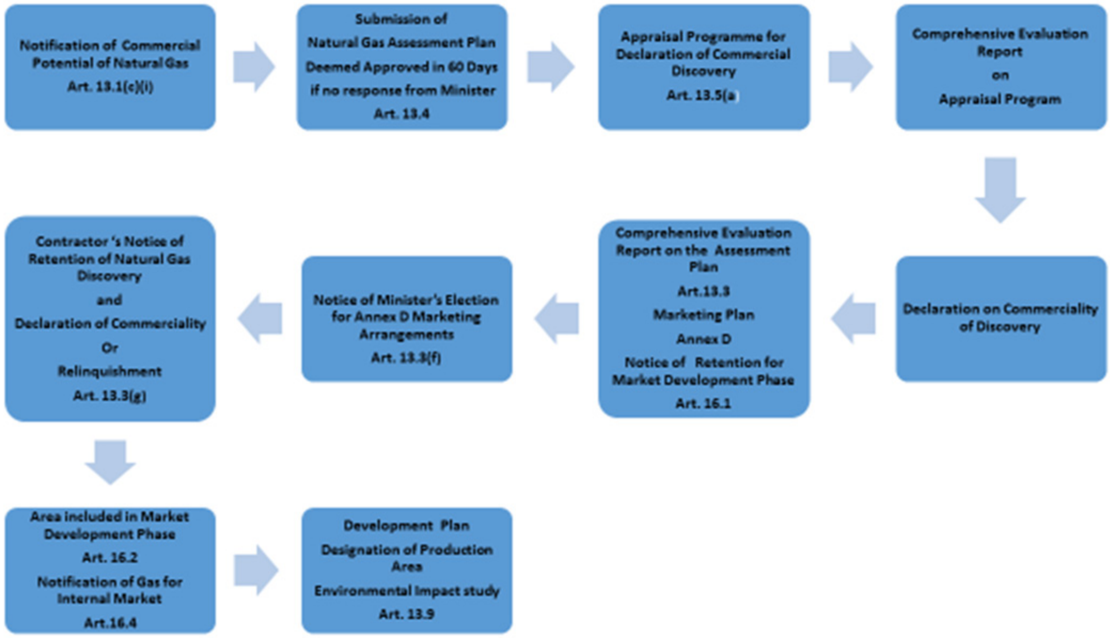
The curtailment program would be subject to the Minister's approval, and would take into consideration the requirements for social needs, such as the generation of electricity; requirements for industrials and commercial users to operate essential equipment to avoid damage to industrial plants; and the availability of alternate sources of fuel or energy to the end-users. For the purpose of the reliability regulation, any licensees supplying gas to the internal and external markets would be considered as a gas supplier.

The adoption of the regulation should be preceded by an opportunity for consultation with and submissions from incumbent licensees. There could be some reluctance on the part of industry participants to comply with the stability regulation. Regulatory interventions in existing energy markets have been upheld in other countries. For example, the pro-rationing of oil production by state regulators was upheld by the U.S. Supreme Court in Champlin Refining Company v. Corporation Commission. Similarly, in Mercury Energy Ltd v. Electricity Corporation of New Zealand Ltd the Privy Council sustained the outright termination of energy supply agreements by a Crown corporation. The Minister will need to consult with the Attorney General regarding the means of implementing the regulation according the jurisprudence of T&T.

14.1.5.4 Petroleum Agreement Annex D Marketing Procedures for Natural Gas

Under a PSC, natural gas development is subject to a multi-step process as shown in the following diagram:

Figure 14-2 Natural Gas Development Approval Process Under PSCs



Within this process, the most critical step is the decision made by the Minister under Annex D Marketing Procedure for Natural Gas that deals with the commitment of GORTT's share of profit natural gas. Annex D is a recent addition to the terms of the Petroleum Agreement. Furthermore, the process for how the contractor is to present information on the marketing options for GORTT's share of gas is not addressed in the Ministry's technical guidance document - GD 06, for Approval of Development Plans.

Several revisions are recommended to Annex D as a means of adding flexibility to GORTT's position. The first change would be to either delete or reword the last sentence in Article 2.1 that commits GORTT's share of gas to the cash payment option in the event that an alternative election is not made within 90 days of so-called option date, being the date that the contractor submits its comprehensive report on the assessment plan under Article 13.3 of the Petroleum Agreement. As a minimum, the Minister should be able to extend the time period in order to conduct a full evaluation of the alternatives, and to propose revisions in the contractor's marketing plan.

An additional revision is needed to give the Minister an ability to review his initial decision to participate in the joint marketing option under Article 2.1(a), where there are changes in circumstances such as developments in the internal and external markets for gas. The Minister should be able to review the initial decision for joint marketing where:

1) The contractor has recovered its costs under Article 18 for the development plan submitted under Article 13.8, including changes under Article 13.9, as approved by the Minister;

2) The contractor enters into marketing arrangements for natural gas that are different than those presented in the marketing plan;

3) It is necessary to supply the internal market; or

4) In the opinion of the Minister, the marketing plan requires adjustment in order to obtain the greatest return to the country consistent with the purpose of the Petroleum Act.

14.2 FISCAL REGIME

The fiscal terms in T&T have evolved significantly. In the 1970s PSCs were introduced in addition to existing EPLs. Under the PSC regime, GORTT take was based on the allocation of a share of production thresholds rather than the fixed royalty under the EPL. This mechanism was changed in the 1990s to a ‘matrix’ that takes into consideration prices as well as production levels. The increase in GORTT take under the PSC was offset by a provision that committed the Minister to pay royalties and other taxes assessed on PSC operations from his share of the profit petroleum.

14.2.1.1 Deepwater Incentives

In 2013, regulations were adopted to provide incentives for exploration in deepwater areas. This included an increase in the cost recovery ceiling from 60% to 80%. The profit share split between GORTT and the contractor is a biddable item. The matrix for profit sharing for natural gas uses both production levels and pricing tiers A to D. The Petroleum Taxes Act defines deep water as being at depths of 400 m or more. The main features of the fiscal regime for deep water in T&T include:

- Annual cost recovery ceiling fixed at 80% for both oil and natural gas.
- A biddable matrix for profit sharing on natural gas with five production levels and four pricing tiers.
- Additional payments for administration, training, and an Environmental Bonus.
- The government’s share of profit gas is taken in-lieu of Supplemental Petroleum Tax, Petroleum Impost, Royalty, and Petroleum Production Levy.
- No carried participation interests for national oil company.
- Royalties in respect of natural gas from State lands or marine areas are assessed at rates of 10 -12.5% of the total gas sales to companies outside the petroleum producing and refining industries during the previous year, at the point of utilisation or export.

Special terms are available for natural gas. A PSC contractor can defer its obligation to develop a natural gas discovery by requesting up to a five year extension as a ‘market development phase’. During the market development phase the contractor is obliged to make an annual payment of US$2 million to the Minister as a holding fee. The amount of the fee can be offset by credits for field appraisal and market studies.

14.2.1.2 New Incentives for Shallow Water

GORTT adopted new fiscal incentives in 2013 for companies investing in oil and gas exploration and production as of 2014. Companies will be able to recover 100% of their exploration costs in the first year of expenditure from 2014 to 2017; as of 2018, they will be able to recover 50% in the first year, then 30% in the second year and 20% in the third year. The 2018 scheme has been applied as of 2014 for oil and gas development expenditures. These measures are primarily aimed at stalling the decline in oil production. Further measures, fiscal and operational would be needed for natural gas. For example, the reduction in the Petroleum Profits Tax to 35% granted for deep water could be extended to marginal fields. In terms of operational issues, the ability to secure access to submarine pipelines would reduce investment costs.

14.2.2 Taxation

T&T has generally placed a higher incidence of taxation on the oil and gas industry in relation to other sectors of its economy. For example, non-petroleum businesses are liable to a corporate tax of 25%, which is globally competitive. In contrast, Petroleum Profits Tax, which is the equivalent of the tax on corporate income, is at either 50%, or at 35% where production is in deep water. In addition to the Petroleum Profits Tax, the following taxes and levies are imposed on petroleum production:

- Supplemental Petroleum Tax (SPL): SPL is imposed on the gross income of companies liable to petroleum profits tax based on the price of oil.
- Petroleum Production Levy: PPL is levied pro rata on every production company with the revenue used to pay a subsidy to petroleum marketers. The maximum charge that can be made is 4% of gross income from the production of crude oil. Small producers with a daily average production of 3,500 barrels or less are exempted.
- Petroleum Impost: Every exploration and production licensee is obliged to pay a petroleum impost in respect of petroleum won and saved at rates per Mcf specified by the Minister. The applicable rate varies and is usually published on an annual basis.
- Green Fund Levy: GFL is charged at the rate of 0.1% of the company's gross income, and applies even if the business is exempt from business levy. Green Fund Levy cannot be credited against corporation tax or business levy and so is an additional tax.
- Unemployment Levy: 5% on the profits of companies subject to the Petroleum Taxes Act.

Deductions are allowed for ordinary business expenses as well as Supplemental Petroleum Tax paid for the period, Petroleum Impost, Production Levy and Royalty. GORTT's profit share allocated under a PSC is not an eligible deduction for tax purposes. Depending on the level of reinvestment, the total current tax rate would appear to reach 65 percent.

Table 14-1 Latest Change in T&T Fiscal Regime

(From Jan 1 2014)

Measure	Current	Revision
Investment Tax Credit	Tax credit of 20% on qualifying capex Tax credit can only be used in year incurred	Unchanged Excess investment tax credit carried forward and offset in arriving at the SPT liability for the year immediately following the financial year in which the credit was generated
Capital Allowances Exploration	<u>Intangible expenditure</u> Initial allowance (Yr. 1) - 10% of costs Annual Allowance (Yr. 1) - 20% of residue <u>Balance</u> Annual allowance (Subsequent years) - 20% reducing balance <u>Tangible expenditure</u> Initial allowance (Yr.1) - 20% of costs <u>Intangible & tangible expenditure</u> Initial allowance (Yr. 1) - 50% of costs Annual Allowance (Yr. 2) - 30% of costs Annual allowance (Yr. 3) - 20% of costs	2014 to 2017 - Allowance of 100% of costs for deep water only
Development	<u>Intangible expenditure</u> Initial allowance (Yr. 1) - 10% of costs Annual Allowance (Yr. 1) - 20% of residue balance Annual allowance (Subsequent years) 20% reducing balance	<u>Intangible & tangible expenditure</u> · Initial allowance (Yr. 1) - 50% of costs Annual Allowance (Yr. 2) - 30% of costs Annual allowance (Yr. 3 - 20% of costs
Work Over & Qualifying Sidetracks	100% deduction of intangible costs incurred in the current year	100% deduction of all tangible and intangible costs incurred

However, there are two significant sources of tax relief. First, most PSCs contain a tax indemnification provision where income/profit based taxes are reimbursed out of GORTT's share of the production. T&T is among the host countries that employ taxes paid in-lieu where taxes are paid by the Ministry on behalf of the oil company. Second, the Petroleum Production Levy and Subsidy Act contains a provision that allows PSC Contractors to 'contract out' of the levy. If the provisions of the PSC conflict, or are at variance with this Act, the provisions of the contract prevail.

In addition, the Petroleum Taxes Act, as well as under the Income Tax (In Aid of Industry) Act, provide a range of allowances and other tax incentives for upstream gas projects in deep water. The main changes in the fiscal regime took effect, retroactively from January 1, 2014 as summarised in the table overleaf.

14.2.3 Upstream and Downstream Oversight

The Petroleum Act and the Petroleum Production Levy and Subsidy Act uniquely give the conditions of the PSC precedence over conflicting laws and regulations. The Petroleum Act was initially adopted in 1962. Rather than engage in a comprehensive revision of this legislation in order to adapt the Act to the rising importance of natural gas rather than crude oil, MEEA has pursued a policy of revising the PSCs as the approach for implementing policy changes. Although this offers a high level of stability for upstream investment in terms of individually negotiated agreements, regulation-by-contract does not create in a regulatory framework where statutes and regulations are the controlling law.

The relationship between the Act and the Regulations also raises questions about upstream versus downstream administration. The principal institutional and regulatory consideration is whether GORTT should reform the administration of the natural gas subsector by the adoption of legislative or regulatory measures in order to further distinguish upstream and downstream activities. The upstream segment is administered under complementary legislation, regulation and contracts. In contrast, the downstream segment is only subject to a licensing process that addresses the technical aspects of the facilities. Economic regulation that covers pricing methodology and access to infrastructure is noticeably lacking.

14.3 GAS SECTOR POLICY

14.3.1 Policy Framework

In the GORTT Freedom of Information Act 2013 Statement the main policy goal was set out as follows:

The main policy goal for the energy sector is to optimally exploit the country's hydrocarbon resources ensuring its efficient administration in order to obtain the greatest returns to the country for the benefit of all citizens.

GORTT's policy framework as articulated in the Manifesto 2010 which cabinet has approved as the Framework for Sustainable Development, refers to the Seven (7) Pillars of Development. The following are complementary policies as identified in MEEA's Cabinet-approved Strategic Plan 2012-2016:

- Increased exploration and production activities for oil and gas;
- Optimisation of the energy value chain;
- Diversification of the energy sector;
- Long-term sustainability of the energy sector by placing greater emphasis on energy efficiency, renewable energy, alternative energy;
- Building a competitive environment for future growth and development;
- Establishment of an appropriate structural framework to allow for implementation of policies which will include the oversight and collaboration with State Energy Companies;
- Internationalisation of T&T's energy sector by going global;
- Listening carefully to the energy sector and its stakeholders, including the trade unions, facilitating learning about the energy sector in the wider population;
- Increased foreign investment ($6 billion in the domestic energy sector); and
- Optimise power generation capabilities.

The Medium Term Policy Framework (MTPF) for the period 2011-2014, which sets the national priorities of MEEA as they relate to the gas sector, is as follows:

- Attract foreign direct investment for new generation downstream plants.
- Take T&T's energy sector global.
- Arrest the decline of the 2P (proven plus probable) natural gas reserves.
- Increase local content in the energy sector.
- Create a more competitive environment for the supply of natural gas.
- Increase domestic use of natural gas.
- Review and reform legislations.

In view of the analysis provided in the Master Plan a number of these priorities will need to be reviewed. The scope for new downstream plants will be limited given the limitations of the projected gas supply and the gas demand already in place. The critical aspect for any new plant will be that it adds more value to T&T than an existing facility. The aspiration to take the sector global is rational and has already achieved some success with services supplied to Latin America and West Africa. The focus for local content should be on increasing the local value added rather than increasing content per se.

Creating a competitive environment for the supply of gas is sensible policy goal but it will be challenging in the light of the current supply prognosis where the immediate need will be to encourage existing producers to develop existing reserves as quickly as possible. Similarly increasing the domestic usage of gas is only likely to be feasible if new gas discoveries are made, and any incremental domestic gas consumption should compete on price with export options.

Clearly going forward there should be a focus on improving energy efficiency, both within existing gas industries and downstream consumers. The most obvious area for efficiency improvement is the power sector where much could be achieved with investment in more efficient generation technology and through demand side management.

14.3.1.1 Role of Gas Sector Policy

The experiences of other countries indicate that a clear gas sector policy is an essential tool to guide sector development particularly where the industry faces major challenges in the future. In our case studies of other countries (Appendix N) with gas industries which have faced a situation of declining reserves, it is instructive that those countries that have made the most rapid turnaround set out clear policies to signal intentions to the industry and other stakeholders.

- In New Zealand the government made a number of policy changes to the gas supply arrangements in recognition of the changes that would come about with the depletion of the Maui field. This included changes to the regulatory approach and third party access to infrastructure. The government also set a timetable for implementation.
- In Brunei the government issued a White Paper which set out 3 strategic goals for the energy sector.
- In Malaysia the policy developments were focused on enhancing development from marginal fields.

It is important for any government to set out a clear energy and gas sector policy to provide guidance and direction to stakeholders.

MEEA issued a Green Paper in April 2014 which sets out the objectives for the energy sector and has a number of policy goals related specifically to the gas sector. This document was never approved but it is clearly a priority tor GORTT/MEEA to develop a new Green Paper as soon as possible. Areas of focus should include:

- Upstream development
  - Embark on an aggressive exploration programme to replace depleted reserves and to achieve and maintain a reserves profile that meets the needs of a growing gas sector.
  - A fair and transparent process for securing third party access to infrastructure.

- Optimisation the natural gas chain

  Re-examine contractual and marketing arrangements with the local LNG sub-sector with a view to optimise and capitalise on growth prospects given the dynamics taking place in the LNG industry and other gas export opportunities.

- Gas-based industries
  - GORTT should promote energy efficiency programmes for gas-based industrial estate companies and create a supportive environment for investment in energy efficiency improvements.
  - GORTT should encourage the use of common user infrastructure at its gas-based industrial estate to promote economic efficiency.

- Reliable and cost reflective power generation
  - Develop an efficient, cost reflective, reliable, energy efficient and environmentally responsible power generation and delivery service in line with international best practice.
  - Maintain an appropriate level of generation reserve to ensure that reliability of supply is achieved.

- Good governance accountability and transparency
  - Governance of the energy sector in a transparent manner with the highest levels of accountability and ethical behaviour.
  - Regulation of industries by robust and respected administrative and legislative framework.
  - Legal, regulatory and fiscal regimes to be continuously reviewed to ensure that they are clear responsive and up to date to support national policies.
  - Clear definition and distinction of the roles, responsibilities and accountabilities of the various stakeholders.

14.3.2 Upstream Industry Challenges

The key challenges facing the T&T upstream gas industry identified previously in the report are:

- A current supply shortfall to both ALNG and NGC, characterised by frequent supply interruptions and reductions.
- The further reduction of gas supply levels due to field decline at some point between 2017 and 2025, with active support for the sanction and execution of planned incremental gas developments and shallow water exploration required to maintain production in this period.
- The need to secure mid-term gas supply from either deepwater exploration success or progress with developing cross-border discoveries in cooperation with Venezuela.

The current supply shortfalls and potential further decline in the short term (2017-25) are intimately linked and will be addressed together. Medium-term supplies from deep water or cross-border gas will be addressed separately

The current supply shortfalls and the risk of further production decline are due to depletion of the large gas fields on which the gas industry was founded and insufficient development of deliverability from new fields to replace that decline. The industry has not responded with sufficient new production capacity because the fiscal terms and gas prices offered have not been sufficiently attractive and the penalties for under supply have not been sufficiently onerous to trigger sanction of the required investments. The situation has been exacerbated by cross-ownership between some producing assets and ALNG trains, causing preferential deliveries to ALNG at the expense of the industries supplied by NGC.

The underlying causes of the short-term supply shortfall and potential further supply decline are examined in Sections 5, 6 and 7. The T&T gas industry structure has evolved to its current form in a period of excess gas supply and a need to stimulate downstream demand to commercialise that supply. In the last five years that situation has gradually shifted to a position where gas supply is insufficient to meet the established demand and it is now maintenance and extension of production plateau that must be stimulated. However the commercial and regulatory structures governing the industry remain from the era of excess supply. Resolution of the upstream supply issues will require overhaul of the upstream commercial and regulatory structures to stimulate supply to meet the downstream gas demand.

MEEA provides administration of regulations for the safe and orderly operation of the upstream industry while NGC and NE are focused on stimulating and actively participating in the transportation and supply of gas to downstream customers. Effective management of the current phase of constrained supply will require active intervention by GORTT agencies with the upstream sector, requiring significant changes in the roles and interaction between GORTT, NGC and NE departments as well as with the industry.

The policy objectives expressed in this section represent a desired end-state. Expanding and defining the required structures to address the supply shortfall is a significant task in its own right. Defining a pathway to amending and replacing the existing structures represents a further challenge and is addressed in the remainder of this section.

14.3.3 Short-Term Gas Supply Policy Initiatives

Stimulation of Upstream Supply

The hurdles which must be overcome and initiatives which can stimulate upstream supply are explored in Section 8 of this report. This concludes that the sanction of projects required to maintain production will in some cases require support and proposes:

- Improving access by incremental projects to existing platform and pipeline infrastructure owned by NGC and other upstream operators to reduce development costs;
- Amending PSC profit split terms that no longer reflect current gas pricing;
- Selectively providing fiscal relief and elevated gas pricing to supply projects that continue to struggle to meet economic sanction hurdles.

The need for transparency in the sector is also noted, requiring that incentives be applied equitably across projects in need of assistance. This will place a significant burden on the regulator tasked with assessing the need for support. The drive for transparency also requires that PSC and License terms are equitably enforced, including relinquishment of undeveloped acreage, to which any exceptions should be clearly linked with obligations supporting stated government objectives, primarily extension of plateau gas production.

Commercial Feedback from Downstream Consumers

The analysis in Section 5 of this report identifies that the shortfall of gas supply to NGC has been significantly greater than that experienced by ALNG, complemented by analysis in Section 9 which identifies that the shortfall within ALNG is also not evenly distributed across the LNG trains. The disproportionate allocation of gas curtailments by upstream suppliers is a result of those suppliers optimising their overall commercial position along the gas supply chain, favouring gas supply to those related party consumers from which they receive downstream rent over those to whom they make arms' length sales.

It is our understanding that few gas supply contracts in T&T have penalties for under supply, although the majority include take or pay obligations on the consumer. This reflects the environment of excess gas supply and need to stimulate demand at the time that the contracts were negotiated, but results in a situation where suppliers do not experience any penalty for diverting restricted gas flows away from arms' length sales contracts to downstream consumers in which they hold a commercial interest.

For the T&T gas market to function effectively in an environment of constrained supply, commercial feedback must be provided to the upstream producers of the consequences felt by downstream consumers from shortfall of supply below the contracted rates. This is typically built into gas contracts through penalties for under supply in terms of penalty payments ("Ship or Pay" terms) as either a compensation payment or reduction in gas prices when gas supplies resume. Introducing these terms into T&T upstream gas supply contracts will effectively price reliability of gas supplies and bring balance to commercial drivers to gas allocation between consumers.

Regulatory Oversight

Two key prerequisites for GORTT to take a more active role in supporting and incentivising the reliable supply of plateau gas to downstream industries are:

- Clarity on the forecast production from fields currently in production, under development and in the planning stages and the capital and operating costs associated with them.
- Resources within GORTT agencies and regulators to effectively engage with the operators and determine where incentives should be offered.

Management of short and medium-term gas supply levels requires regular updates from operators on their production plans. Short-term detailed forecasts are required to help NGC react and provide notice to consumers of supply interruptions. This is required at on hourly basis for the immediate few days in the future, with decreasing granularity for longer range forecasts, such as daily for the next month, weekly for the next 6 months.

An understanding of forecast performance of existing production systems and projects to support contracted production over the next 12-36 month period is required to allow targeting of incentives and initiatives to secure sanction of the planned development projects. The timeline of production from new investments varies greatly from a few months for well interventions to a few years for greenfield developments. Forward production forecasts, development plans and cost profiles on a monthly or quarterly basis will be required to understand the forward profile and engage with the critical projects and operators. In most cases there are already obligations on the operators to provide production and cost information to the regulators. The key to fully leveraging this information will be for it to be regularly updated and supplied on a consistent basis and format to facilitate analysis of the overall supply position to NGC and ALNG.

Interpreting this data in a timely fashion and subsequently engaging with the operators on critical issues requires a significant level and capacity of skilled staff in the GORTT agencies concerned. The competition for this staff and consequently the cost of engaging them should not be underestimated but it is vital to the success of the industry that this capability is secured. The operators will be allocating experienced staff to negotiate any matters relating to fiscal terms and contract gas prices and GORTT must be ready to engage on an equal basis.

Upstream Policy Summary

A coherent structure of policy initiatives emerges from this analysis which is summarised in Table 14-2. The table divides initiatives into incentives and penalties for upstream operators to improve security of supply and pursue exploration and development of resources. In addition the provision of information by operators needs to be structured to allow easier collation and interpretation by GORTT agencies and allow then to maintain oversight of the gas industry.

At a high level the policy initiatives can be condensed in to a set of incentives and penalties for the upstream operators. Fiscal incentives, flexibility on gas prices and discussion of relinquishment terms will be used to stimulate developments. However, operators must accept Ship or Pay gas sales contracts and more open access to infrastructure as an overhaul of the commercial restructure of the gas industry.

The recommended form of these initiatives is discussed in Section 8 and summarised here for convenience:

- Ship or Pay gas sales terms
  - This is a foundation of sector reform as it introduces a penalty to undersupply to third party buyers to offset the incentive to supply to related party buyers.
- Access to infrastructure:
  - Industry Code of Practise defining the principles upon which users negotiate terms of access with infrastructure owners;
  - Backed up a regulator with the power to enforce terms where an owner is perceived to be acting unreasonably;
  - Enforced terms would follow the code of practise principles and favour gas supplies contracted under Ship of Pay terms;
- Fiscal and gas price support:
  - Revision of PSC profit split to a set of price bands relevant to the current market;
  - Negotiated access to pre-defined fiscal incentives depending on project needs;
  - Negotiation of gas prices required to stimulate development of resources;
  - Potential to extend relinquishment terms where it will support delivery of gas under ship or pay terms, balanced by enforcement of responsible development obligations to counter reserves warehousing or preferential supply to related party supply consumers.

Table 14-2 Upstream Supply Policy Overview

Security of Gas Supply	Exploration and Development of Resources
Incentives	
Gas Pricing	Gas Pricing Fiscal Terms Access to Infrastructure Capacity Negotiation of relinquishment terms
Penalties	
Ship or Pay Gas Sales Contracts Competition for Infrastructure Capacity	Competition for Infrastructure Capacity Responsible development obligations
Regulatory Obligations	
Structured short term production data	Structured medium term production forecasts, development and production costs

14.3.4 Medium-Term Gas Supply Policy Initiatives

Medium-term gas supply opportunities can be pursued through deepwater exploration success and subsequent development in parallel with pursuit of agreement with Venezuela to develop cross-border gas resources particularly at the large Manatee Loran field.

Deepwater Gas Supply

The potential for mobilising deepwater gas production is examined in Section 8.3. The focus for T&T at this stage should be to expand the number of blocks under license with firm drilling commitments. This will be challenging in the current environment of reduced expenditure across international oil and gas companies, however opportunities for stimulating increased activity should be explored including:

- State-sponsored seismic acquisition
- Review of fiscal terms and alignment between GORTT and operator incentives
- Road shows to advertise new fiscal terms and seismic data

Cross-Border Gas Supply

The issues surrounding supply from cross-border fields are examined in Section 8.4. While it is understood that the nature of these negotiations will be complex, it is recommended nonetheless that further initiatives are taken, including:

- Setting clear deadlines and timelines within GORTT for progress of the discussions with Venezuela;
- Comprehensive evaluation of the value to T&T of securing an arrangement whereby 100% of produced gas is processed through its existing infrastructure to allow specific value propositions to be formulated and when appropriate presented to the Venezuelan government;
- Consideration of how agreement to develop the gas reserves could form part of a broader bilateral agreement with Venezuela.

14.4 REGULATORY IMPLEMENTATION

14.4.1 Upstream Regulatory Initiatives

The preceding upstream sections have identified initiatives for securing continued and reliable plateau gas deliveries to downstream industries:

- Amending fiscal terms in PSCs
- Amending fiscal terms in Production Licenses
- Shared access to Infrastructure
- Variation of gas prices and Ship or Pay gas sales terms

This section addresses at a high level the regulatory approaches to implementing these initiatives.

14.4.1.1 Amending Fiscal Terms in PSCs

PSC terms are the result of individual negotiation between GORTT and the contractor. Although the model and executed PSC examples provided for review contain no provision that expressly provides for amendments to be made to these agreements, the parties would nevertheless be free to mutually agree to appropriate changes.

To ensure transparent application of PSC amendments it is recommended that MEEA prepare model amendments which would be submitted to the contractors as the basis for the negotiations. Initially this would apply to revision of the gas pricing bands in the profit split matrix for PSCs from the 1996-2005 period, together with any amendment to cost recovery schedules deemed appropriate for pre-emptive implementation.

The ability of GORTT to offer specific fiscal incentives to a development project which is deemed to be marginal must also be available, specifically modifying cost recovery terms and ring-fencing incremental production from existing producing projects within the same PSC. Again amending the PSC by mutual agreement can effect these changes, however for the sake of transparency standardised agreement terms should be formulated which can be applied to each project to minimise the risk of inconsistencies arising between marginal project terms.

14.4.1.2 Amending Fiscal Terms in Production Licenses

The Production License is a regulatory instrument rather than a negotiated agreement and consequently any incentives would have to be addressed by reference to the existing clauses in the body of the License. The tax relief proposed in Section 8 of either a reduction in the rate of taxation to that equivalent to the 35 percent offered for deepwater PSC's, or a tax indemnity comparable to that incorporated in Article 21.5 of the PSCs, would require an amendment to the Petroleum Taxes Act and could therefore not be administered on a case by case basis to stimulate specific marginal developments. However, as an alternative it would be possible to agree to a reduction of the royalty for natural gas under Clause 50 (3) (a) on a case-by-case contractual basis.

The approach for Production Licenses would therefore become application of any blanket changes required to terms through legislative change to the Petroleum Taxes Act (which would then also apply to existing producing fields), combined with variation in royalty rates levied on specific marginal developments to support project economics.

14.4.1.3 Access to Infrastructure

An important enabler to the development of remaining gas fields will be to ensure efficient use of existing infrastructure to reduce the capital cost of resource development. A voluntary code of practice is recommended to guide individual commercial negotiation of access rights between developers and infrastructure owners. GORTT should take a key role in facilitating agreement on a code of practice which can be adopted by all operators and which achieves the objective of maximising reasonable usage of infrastructure.

In addition GORTT needs the ability to impose a settlement on parties it is reasonably believed that negotiations are not progressing in line with the code of practice. A possible mechanism for imposing settlements would be for the President to exercise his rule-making authority under the Petroleum Act, but further investigation and possibly legislation may be required to allow this to occur and to define the principles upon which settlements would be formulated. Key principles would include alignment with the code of practice and potentially could include favouring parties prepared to supply gas on a Ship or Pay basis over legacy "reasonable endeavours" suppliers. Finally allowing reasonable third party access to existing infrastructure should be included in the terms of any new PSCs or extension to existing PSCs and Licenses.

14.4.1.4 Variation of Gas Prices and Ship or Pay Gas Sales Terms

A further method of stimulating marginal field development available to GORTT is the ability to offer higher gas prices to marginal fields. This can be achieved through modifications to existing gas sales contracts or execution of an additional sales contract by mutual agreement.

Reliability of gas supplies will be encouraged through inclusion of Ship or Pay terms in gas sales agreements. This term can be included by NGC in all new gas sales contracts and should be introduced when modifications are negotiated to existing gas contracts, e.g. for stimulation of marginal fields. GORTT should take advantage of other opportunities, such as extension of PSCs, to introduce this term.

14.4.1.5 Further Stimulation of Resource Development

The recommendations in this Gas Master Plan include both incentives and penalties for gas producers and under some circumstances the operators may be reluctant to proceed with developments in a timeframe necessary to support reliable supply of plateau gas volumes.

Operators have accepted an obligation for diligent development under the terms of the PSC and EPL and this may offer another negotiating path to GORTT. For example, PSC contractors are obligated to conduct their petroleum operations in a "diligent and workmanlike manner". A licensee under an EPL has an identical obligation. Failure to develop a discovery that is otherwise commercial could be considered to be a breach of this obligation.

It is not clear what the consequences of the breach of the covenant of due diligence would be under the jurisprudence in T&T, and advise should be taken from the Attorney General. However, in other petroleum regimes the failure to develop a petroleum discovery is considered a material breach of contract, the remedies for which are monetary damages and cancellation of the underlying contract on the basis that the obligation of due diligence serves the public interest. Implementation would require litigation.

14.4.2 Downstream Regulation

14.4.2.1 Approaches to Regulation

Global Experience

Global approaches to downstream gas sector regulation have evolved over the last several decades in line with the evolution of gas markets and structures. These are discussed in detail in Appendix J but can be summarised as follows:

There are three main approaches for the assignment of powers to regulate and oversee the sector:

- Separation-of-powers model: an independent technocratic agency has regulatory powers.
- Ministry-dominated model: the petroleum ministry or an equivalent executive body is charged with regulation and oversight.
- NOC-dominated model: the NOC has de jure or de facto responsibility for day-to-day regulation, sometimes including the power to award exploration/production licenses.

Many countries have moved towards the separation of-powers model as the most likely to bring about clarity in roles and responsibilities by separating the licensing/monitoring/regulatory body from the policy-maker. However in small markets or markets with low institutional capacity governments may choose to concentrate resources within one institution, usually the Ministry of Energy or the NOC.

It is noted that there are risks associated with the concentration of responsibilities in Government organisations – while this approach allows the Government to build and maintain capacity within a single institution, with cost and resources capacity benefits it comes with the checks and balances inherent in separating oversight functions from policy development.

The T&T model

In T&T MEEA has responsibility for regulation although (with the exception of upstream exploration and production), the natural gas sector in T&T is largely unregulated and left to function under a series of commercial agreements that allocate production to either internal or external markets. Historically NGC has played a form of regulatory role in the midstream sector in as much it has been responsible for setting pipeline access and tariffs, and technical expertise in regard to transportation development and operations is largely to be found within the NGC organisation.

It is recognised that in T&T is rather unusual in that the downstream gas transmission and distribution system is very small in relation to the large volume of gas that is transported and makes up a very small proportion of the overall costs in the gas value chain. Therefore economic regulation of transportation services has been of much lesser concern than in most other countries. The specifics of the T&T gas sector structure, its competitiveness and the role of NGC are discussed at length in Section 12.

14.4.2.2 Recommended Regulatory Oversight

If the T&T gas sector was expected to expand and develop for the Master Plan period then there would be the basis to advocate an independent regulatory function to provide oversight of the commercial (and technical) activities of the gas sector. Such a regulator would be expected to oversee the management and production of T&T's gas resources and ensure that all actors in the sector comply with regulations and do not engage in anti-competitive behaviour.

However, as identified in the Section 11, the sector is facing major challenges over the next 10 years, and in particular to the period up to 2019. Existing planned gas supply from upstream players will not meet existing demand which will result in shortfalls through to at least 2019. There will need to be an immediate and major focus on developing new fiscal terms with upstream players to stimulate future gas supply, in particular from more marginal fields, which make up a significant portion of T&T resources. A third party access regime to upstream infrastructure needs to be developed. In addition GORTT through MEEA will need to focus on securing better value from gas exports, notably LNG and the relicensing/restructuring of ALNG will be a major undertaking. Other downstream buyers will face a more competitive market environment and will be seeking more competitive gas supply from GORTT.

Against this backdrop, and recognising that MEEA is already short of experienced resources, the establishment of an independent regulatory function, the recruitment of competent staff and the development of processes and procedures over the next five years would be an immense challenge and is likely to be major distraction for the most immediate tasks at hand such as mobilising incremental gas supply.

At this point in time, rather than attempting to establish an independent downstream regulator for the gas sector, as many governments have done, Poten recommends that MEEA undertake the regulatory functions associated with standards and access regimes and that NGC maintains its role as aggregator. MEAA should retain its current role in setting policy and establishing the standards for industry performance regarding competition, curtailment planning and facility access. At the same time, administration of the gas sector requires that industry and government are intrinsically linked through a competent authority (NGC) that can provide a more finely-tuned level of operational and market oversight.

In recommending keeping NGC in this critical role of gate keeper and clearing house in the centre of the gas industry there are two critical conditions:

- That the upstream and downstream interests currently held by NGC are divested, and
- NGC's role of aggregator and transporter is performed as a statutory body. This approach is intended to ensure that gas trading and transportation functions are conducted according to clear rules, without the distractions of external political and commercial agendas that burden state-owned holding companies. NGC would report to the Minister, who would be responsible for appointing its board of directors according to clear criteria for their experience and competence.

14.4.2.3 Future Regulatory Oversight

In the longer term, GORTT should consider the development of a formal regulatory function to provide oversight of the commercial (and technical) activities of the gas sector. This regulation could come in the form of an independent regulatory body or from within GORTT, for example with a performance agreement with MEEA/MOFE with annual reporting and audit requirements, or with stronger monitoring within MOFE. The rationale for the establishment of a formal regulatory body would be to provide greater transparency in oversight. On a broader level the development of a regulatory function overseeing the gas sector could be considered to be good practice in the stewardship of the sector.

However the establishment of a regulatory body has a cost and would take time to establish. Amongst the issues to be addressed include:

- The development of a body to undertake regulatory oversight is a non-trivial activity. Regulations need to be developed and the regulatory body needs to be staffed with competent personnel who understand the operation of the sector from a technical, commercial and legal perspective.
- There are a limited number of appropriately skilled people in T&T to undertake the necessary roles with an appropriate level of knowledge and authority. Such people would be mostly in the private sector. Attracting the people required to populate a regulatory function would require appropriate remuneration packages which may not be aligned with those of ministry institutions.
- There is a cost to developing a regulatory body. Typically this is paid for by the industry in the form of a levy on services provided, but such a mechanism would need to be established.

14.5 HSE POLICIES AND PRACTICES

14.5.1 Occupational Health and Safety

14.5.1.1 Legal and Institutional Framework

Occupational health and safety are governed by the Occupational Safety & Health Act 2004, and the Occupational Safety & Health (Amendment) Act 2006.

The "Occupational Health Unit" within the Ministry of Health and the Ministry of Labour and Small and Micro Enterprise Development (MOLSMED) are the competent national authorities for safety and health at work[1]. The OSH Authority was established in 2006. The Authority is a multi-stakeholder[2] advisory body to the MOLSMED, whose primary function is policy formulation. The core tasks of the Authority are to encourage the enforcement of the OSH Act, promote training and research, provide information on standards and OSH matters, and develop / make recommendations on regulations and codes of practice.

The OSH Agency is the enforcement arm of the Authority. The main objective of the Agency is to ensure compliance with the OSH Act and related regulations in accordance with the enforcement policy that encourages voluntary compliance in the first instance. One of the targets for the Agency is to work towards the building and sustaining of a modern, efficient and highly professional Safety and Health Inspection Service that meets international standards. The Chief Inspector is the head of the Inspectorate within the OSH Agency.

The Occupational Health Unit in the Ministry of Health conducts surveys to assess occupational health and safety conditions in industrial establishments and provides advice where necessary. Inspectors report findings and recommendations to the relevant Regional Health Authority. There may be some duplication between the two responsible Ministries; for example, complaints about unsafe practices and subsequent investigations may be made through the County Medical Officers of Health or the OSH Agency.

The obligations placed on employers, employees and government in the OSH Act, as amended, and the institutional framework for safety and health are in line with good practice internationally. Employers are required to ensure the safety of their employees and others at their premises. The OSH Act requires an annual risk assessment to be conducted to identify actions required to comply with the Act or other statutory obligations. The OSH Act requires that approval be sought from the Chief Inspector before undertaking any major construction related activity.

14.5.1.2 Safety Statistics

According to data from the International Labour Organization (ILO), occupational injuries in T&T are comparatively low compared with other countries, for example below European countries such as Germany, Finland and Sweden (Figure 14-3). Almost half of all occupational injuries occur in the manufacturing sector (Figure 14-4).

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[1] Related information from the "Occupational safety and health country profile: Trinidad and Tobago", International Labour Organization

[2] The Board of the OSH Authority comprises 16 members, nine drawn from employers, employees and relevant organisations, four from relevant Ministries (Health, Labour and Small and Micro Enterprise Development, Energy) and the Trinidad & Tobago Bureau of Standards, plus Chairman and Deputy Chairman appointed by the Minister.

Figure 14-3 International Comparison of Non-Fatal Occupational Injuries

Average incidence rate 2002-06[3]; Countries for which comparable statistics are available (source: ILO)

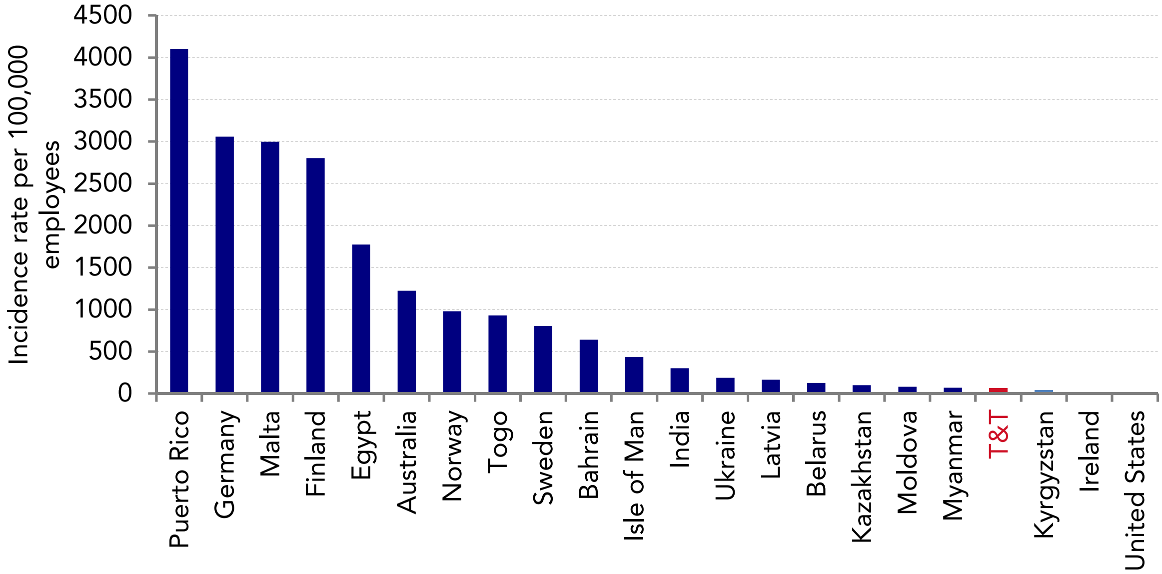
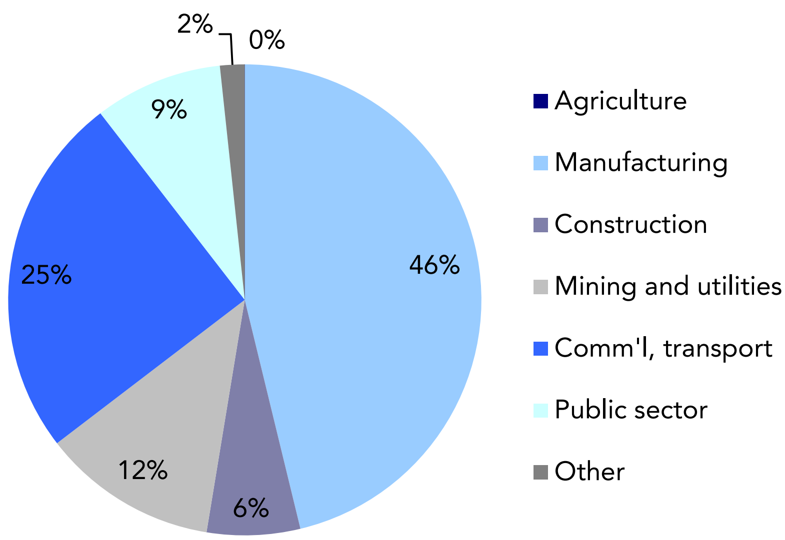


Figure 14-4 Non-Fatal Occupational Injuries by Sector in T&T, 2010

(source: ILO)



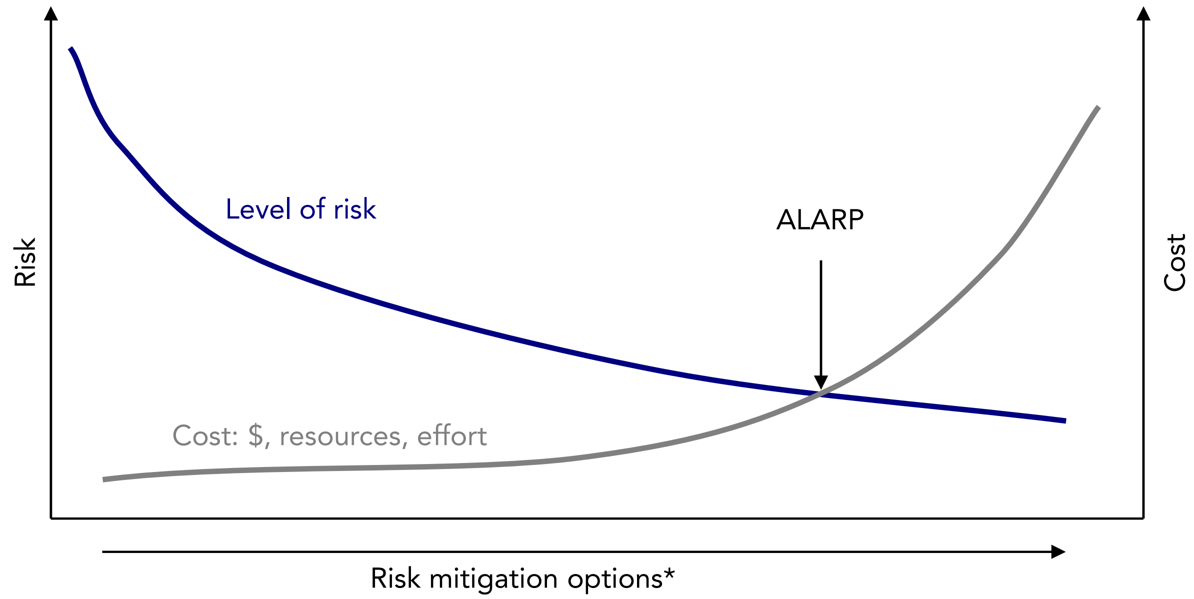
14.5.2 Safety

No guidance has been found on specific safety requirements for T&T. A typical requirement is that technology should be selected to minimise risk to health, safety or environment to a level As Low As Reasonably Practicable, the so-called ALARP principle. Normally there are also absolute limits that must be met, e.g. for emissions or risk to the general public. The concept of ALARP is described by the UK

[3] Statistics for Trinidad & Tobago not available for 2007-08, but resume 2009-10.

Health & Safety Executive (HSE) on their website[4]. The key is the phrase "reasonably practicable", where the reduction in risk is weighed against the "trouble, time and money needed to control it" – cost is generally the deciding factor. In most cases reasonably practicable refers to a body of good practice established over time through discussion with stakeholders.

Figure 14-5 Illustration of the ALARP Principle



* The changes in risk and cost are not normally a smooth continuum; the chart merely illustrates how the ALARP principle may be visualised.

14.5.3 Environment

14.5.3.1 Legal and institutional framework

The responsible Ministry is the Ministry of Environment and Water Resources (MEWR), with monitoring and management of the environment being the responsibility of the Environmental Management Authority (EMA). The EMA was established in 1995, pursuant to the Environmental Management Act, 1995, which was later repealed and replaced by the Environmental Management Act, 2000. The EMA's role includes developing, implementing and monitoring the National Environmental Policy; the current policy dates from 2006. The EMA is mandated to write and enforce laws and regulations for environmental management, to educate the public about environmental issues and to control and prevent pollution, as well as to conserve natural resources.

Activities that could harm the environment are called Designated Activities, and require consultation with the EMA. Designated Activities are listed in Designated Activities Orders, which are amended from time to time, the most recent being 2008. All oil and gas activities are considered as Designated Activities.

14.5.3.2 Environmental Permitting

The environmental permitting requirements are set out in the Certificate of Environmental Clearance Rules 2001. The EMA is responsible for environmental permitting and the issue of "Certificates of

[4] ALARP "at a glance": http://www.hse.gov.uk/risk/theory/alarpglance.htm.

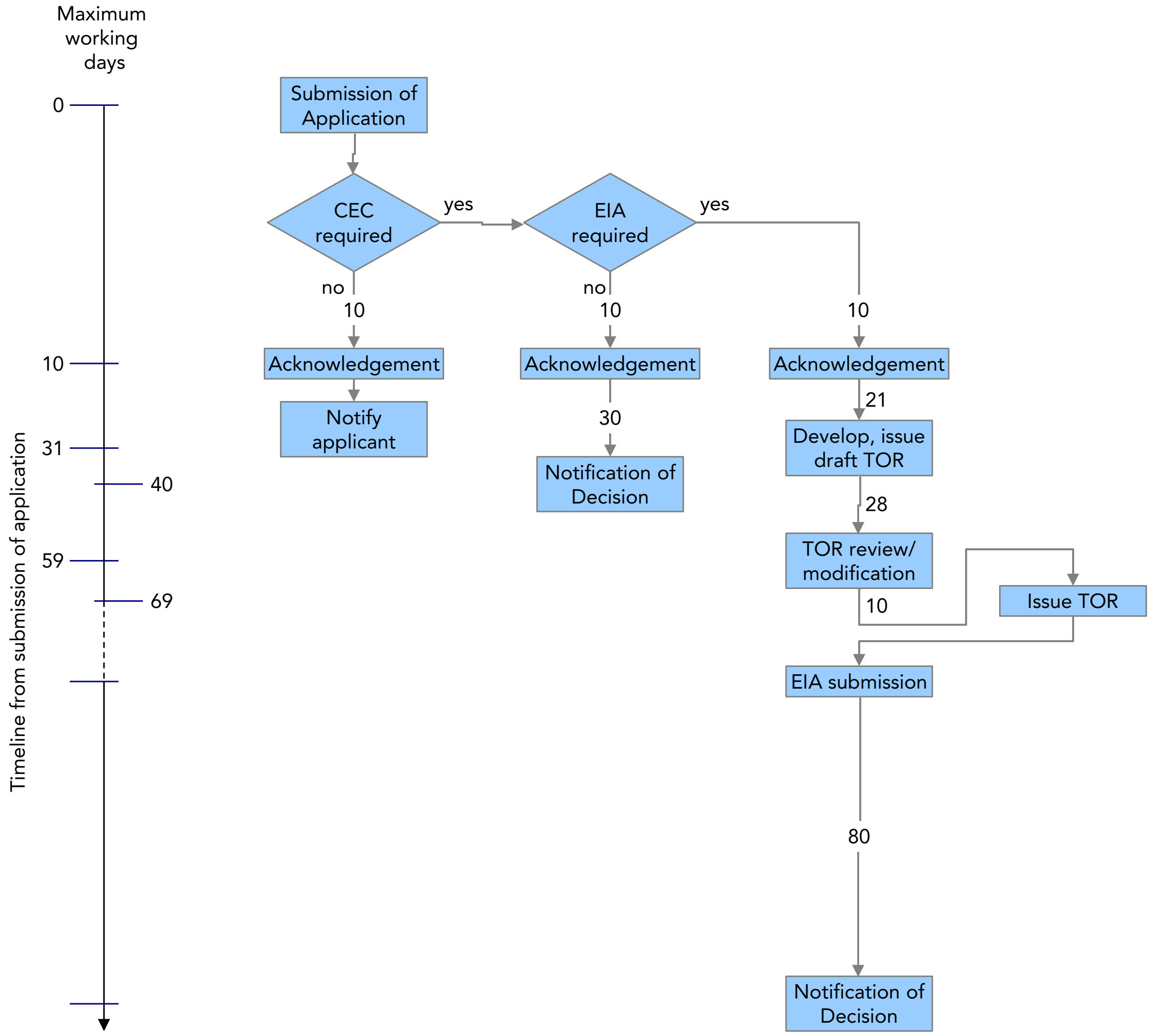
Environmental Clearance". The EMA reviews safety as well as the environmental aspects of an application.

CEC Process

The EMA first determines whether a Certificate of Environmental Clearance (CEC) is required and then whether a project also requires an Environmental Impact Assessment. The CEC application process is shown in Figure 14-6 below. The process requires Terms of Reference (TOR) for the Environmental Impact Assessment (EIA) to be agreed by the EMA before the EIA can start.

The TOR as issued will propose a suggested table of contents for the EIA, but does not constitute a definitive description of the required content of the EIA and includes a disclaimer from the EMA to that effect. Depending on the project, an EIA may require risk analysis, Health & Safety Management Plan, Emergency Response Plan, and Environmental Management Plan, plus respective Monitoring Plans. Public consultation will also be required; the TOR will prescribe the level of engagement.

Figure 14-6 The CEC Application Process



It should take a maximum of just over three months (69 working days) from submission of an application to final agreement on the terms of reference, and of almost four months (80 working days) for the EMA's review and decision on the submitted EIA. In fact, it can take longer still as the EMA is entitled to ask for further information at any stage, and may delay a decision for up to 30 days after receipt of the requested information. An applicant has 28 days to appeal against a decision of the EMA.

A 2014 report by The Energy Chamber of T&T noted several obstacles to quick determination of CEC applications, including the absence of a dedicated department to process oil and gas applications. The report proposed four key recommendations to speed up the application and review process:

- Review the TOR process to develop options to negate the requirement for a TOR;
- Improve the EMA's online platform to allow applications and related information to be tracked in real time;
- Host a multi-stakeholder forum to better define EIA requirements and processes;
- Ensure MEEA assist in technical reviews and provide training for EMA personnel in oil and gas applications.

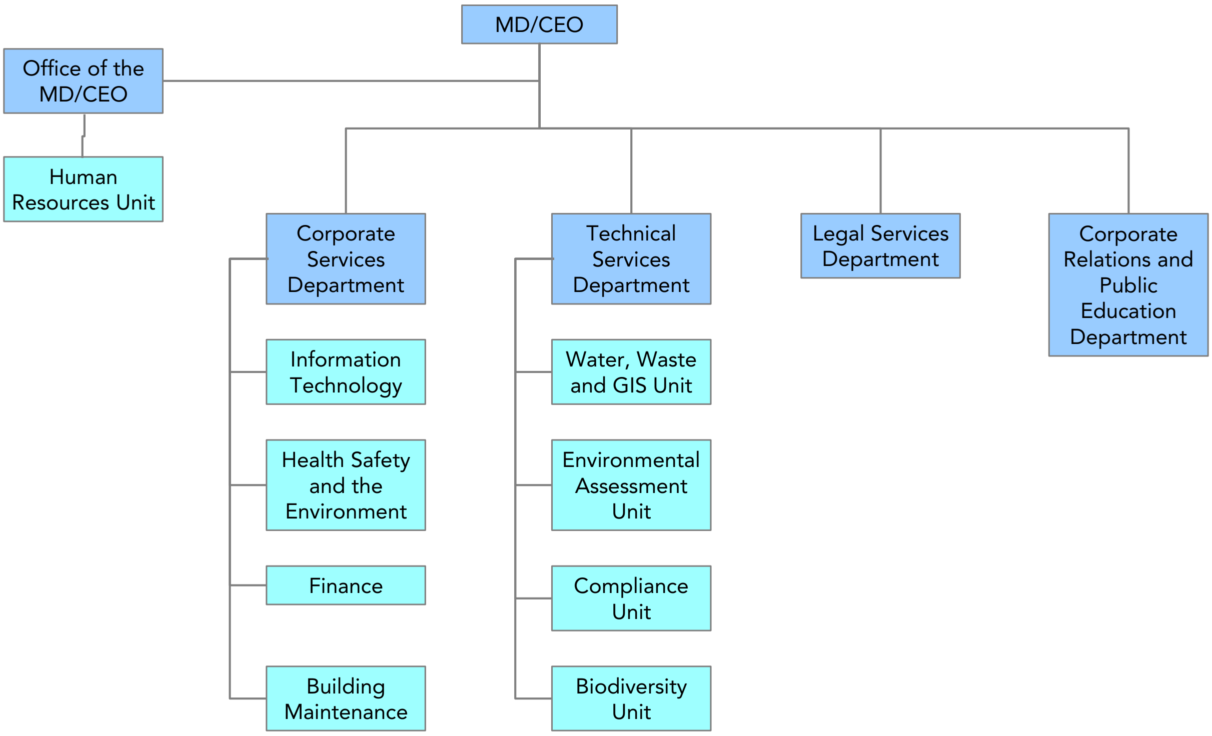
The Energy Chamber report also noted considerable variation in the time taken to finalise TOR and review the EIA, with delays of up to 16 weeks overall.

Staffing Issues

The organisation of the EMA is bureaucratic, with the key Environmental Assessment Unit hidden within the Technical Services Department (Figure 14-7). The total staffing level in 2010 was 120. A Stakeholder Survey conducted ahead of the EMA's 2010-14 Strategic Plan noted that 60% of respondents identified staff-related problems and bureaucracy as major challenges to the EMA, and a lack of experience and technical capability. The Strategic Plan acknowledged a number of weaknesses, including a lack of staff with the required skills and experience, and proposed the recruitment of academically-qualified individuals, who would be trained during their employment. Given the apparent shortage of experienced staff, it is difficult to see how this could be done effectively. The Strategic Plan also recognised the need for a restructuring of the organisation.

Figure 14-7 EMA Organisation

EMA 2010-14 Strategic Plan, Appendix 3



14.5.3.3 Industrial Emissions

Industrial emissions must comply with rules issued by the Minister of Environment and Water Resources made under Section 26 of the Environmental Management Act 2000, including:

- Water Pollution Rules 2001, as amended by the Water Pollution (Amendment) Rules, 2006;
- Air Pollution Rules 2014;
- Waste Management (Hazardous Waste) Rules 2014 – currently in draft form.

The EMA has an Environmental Police Unit and the weight of the courts to enforce compliance.

EU practice to aid in the implementation of the 2010 Industrial Emissions Directive (2010/75/EU) is to develop and publish design reference documents called "Best Available Techniques Reference Documents" (BREFs). Each document generally gives information on a specific industrial or agricultural sector in the EU, on the techniques and processes used in this sector, current emission and consumption levels, techniques to consider in the determination of the best available techniques (BAT) and emerging techniques. T&T could consider requiring industries to comply with these BREFs or other similar references.

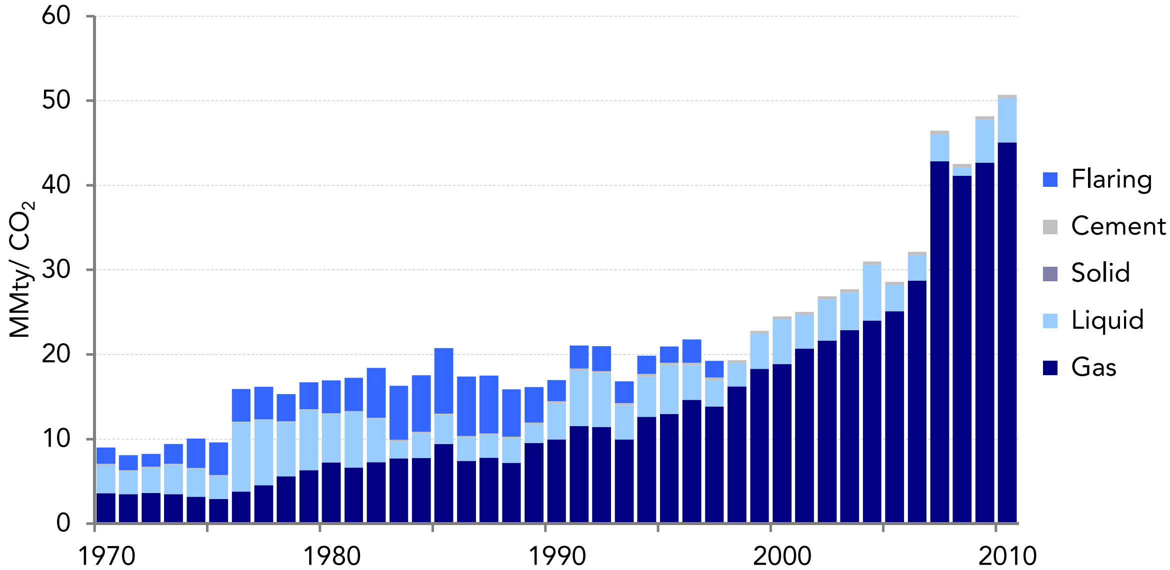
14.5.3.4 Gas Release (Flaring)

Gas flaring is permitted provided that the operator has reinjected as much gas for storage as is consistent with good petroleum industry practice and has taken reasonable measures in agreement with the minister to recover natural gasoline and other liquids contained in the gas[5]. Flaring is regulated by MEEA.

CO_2 emissions data published by the US DOE's Carbon Dioxide Information Analysis Center show that in the mid-1980s gas flaring was contributing almost 40% of total T&T CO_2 emissions (Figure 14-8). Flaring was eliminated in the late 1990s (see Figure 14-9) with the start-up of Train 1 at ALNG in 1999, which provided a ready market for the surplus gas.

Figure 14-8 Total Fossil Fuel CO_2 Emissions for T&T[6]

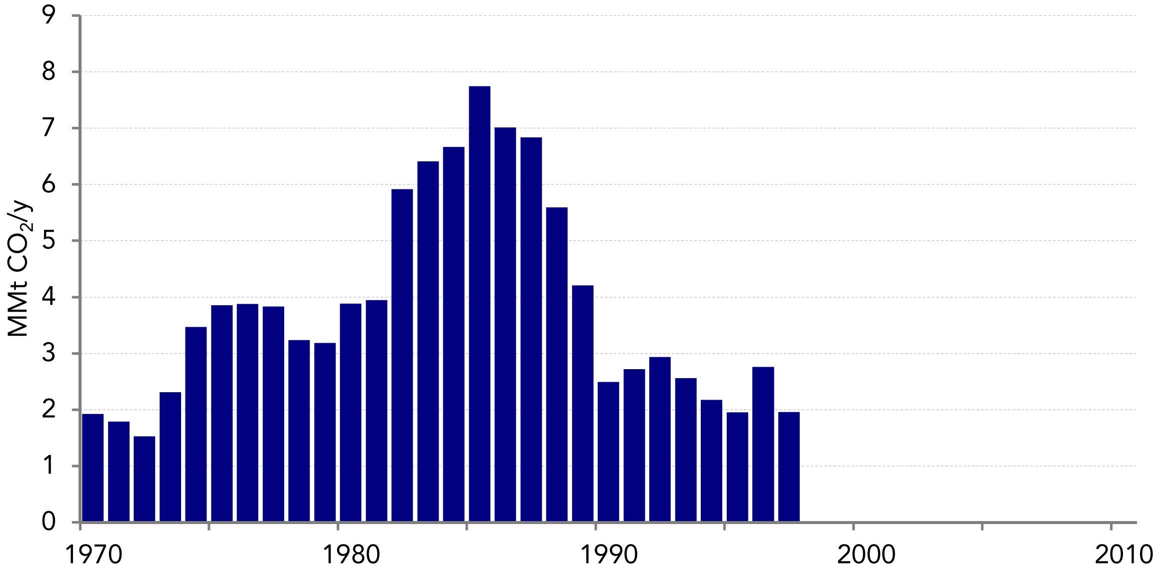
(source: CDIAC)



[5] "Regulation of Associated Gas Flaring and Venting: A Global Overview and Lessons", published by World Bank Group: Global Gas Flaring Reduction Public-Private Partnership, 2004

[6] Boden, T.A., G. Marland, and R.J. Andres. 2013. Global, Regional, and National Fossil-Fuel CO2 Emissions. Carbon Dioxide Information Analysis Center, Oak Ridge National Laboratory, U.S. Department of Energy, Oak Ridge, Tenn., U.S.A. DOI: 10.3334/CDIAC/00001_V2013

Figure 14-9 T&T CO_2 Emissions from Flaring
(source: CDIAC)



14.5.3.5 CO_2 Emissions

T&T in principle supports efforts to reduce greenhouse gas emissions as it recognises its vulnerability to the consequences of climate changes. The following policies have been enacted:

- National Environmental Policy 2006
- National Climate Change Policy 2011

Given the dependence of the T&T economy on the oil and gas sector, T&T's energy efficiency performance expressed in GDP per MMBtu lags the other Caribbean countries (see Figure 14-10).

Figure 14-10 Economic Productivity & Energy Efficiency for Caribbean Countries (2010)

(source: Caribbean Climate Innovation Center)

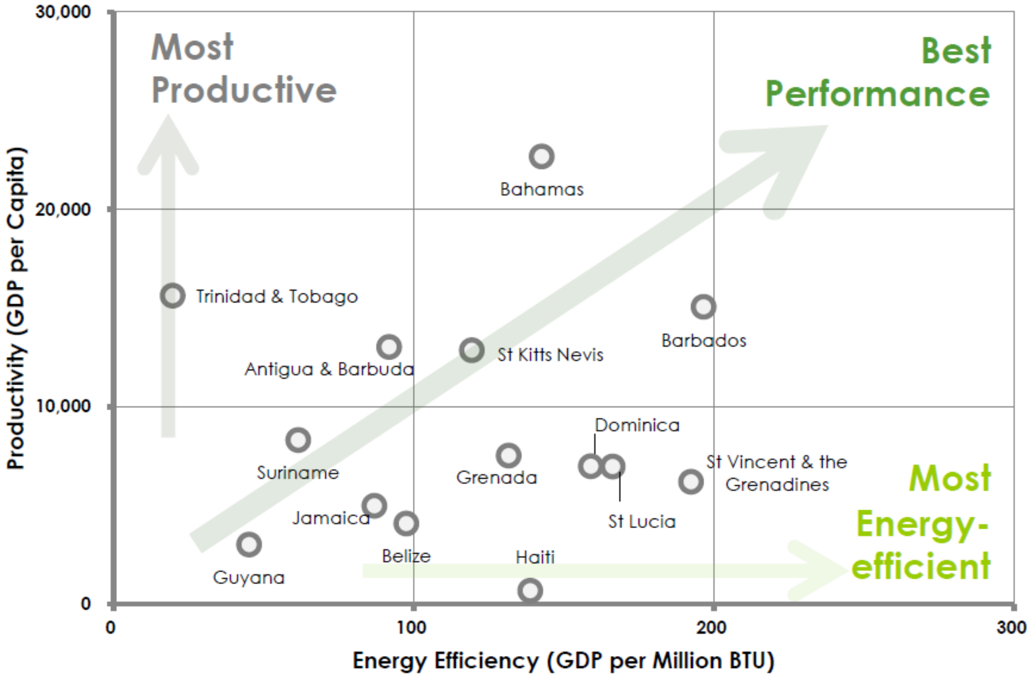


Figure Economic Productivity and Energy Efficiency (2010)

Figure 14-8 shows how total CO_2 emissions continue to rise. A large jump of over 14 million tonnes between 2006 and 2007 – a 45% increase – followed the start of commercial operation of ALNG Train 4[7]. GORTT is seeking to reduce emissions, for example promoting the use of CNG as a vehicle fuel. MEEA has also created a website (myenergytt.com) to encourage domestic consumers to reduce their use of energy as part of the 2013 "My Energy, My Responsibility" campaign.

Policy 23 of the 2014 draft National Spatial Development Strategy requires "Planning Authorities to apply the 'energy hierarchy' (energy reduction, energy efficiency, renewable energy, clean and efficient use of non-renewables) to decisions and plan-making processes".

However, GORTT could consider raising energy prices, which would make it easier for all consumers to judge how best to adjust their behaviour and investment patterns. Although subsidised energy prices do lower energy costs for the poor, in practice it is larger consumers who benefit the most. The use of energy subsidies is generally recognised as an ineffective and costly way of helping the poorer sections of society; higher prices and targeted relief would be more effective, and would reduce the influence of world energy prices on the size of the subsidy.

[7] The jump is not entirely consistent with ALNG production data

14.6 LOCATION OF GAS-BASED INDUSTRIES – LAND USE PLANNING

14.6.1 Legal and Institutional Framework

Land use is governed by the Planning and Facilitation of Development Act 2014 (PAFD Act), which was passed in October 2014 and is awaiting proclamation. The PAFD Act supersedes the Town and Country Planning Act Chapter 35:01 of 1960. The responsible ministry is the Ministry of Planning and Sustainable Development (MPSD). The Act establishes the National Physical Planning Authority of T&T (the National Planning Authority, NPA) as the competent authority responsible for "facilitating good and sustainable development". The NPA is created as a statutory corporation.

Inter alia, the NPA will be responsible for the National Spatial Development Strategy (NSDS). The PAFD Act allows the Minister to issue Development Orders granting permission for land to be developed; Development Orders may impose conditions and limitations. The Act also allows the NPA to issue a discontinuance order requiring discontinuance of an activity in the interest of "proper planning of an area" or to impose conditions on continued use. The PAFD Act requires the preparation of any local or regional development plans to include consultations with the public and with key stakeholders; development plans must be submitted to the NPA for review.

Currently, the NPA's functions are discharged by the Town and Country Planning Division (TCPD) within the MPSD. The TCPD's main responsibilities are stated as follows:

- Develop and keep, under review, a comprehensive policy framework, a national physical development planning framework, regional plans and local area plans to guide decision making on the use and development of land
- Evaluate and determine on behalf of the Minister, applications for planning permission to develop land, in accordance with land use policies and plans
- Evaluate and determine applications for the display of advertisements
- Enforcement of planning control
- Assist in the preparation and review of relevant planning legislation
- Provide an up-to-date database of land use planning data and information for decision making on land use and land development
- Maintain the register of planning applications

At a local level, planning is the responsibility of the 14 Municipal Corporations under the Ministry of Local Government, which are charged with preparing Municipal Development Plans and Local Area Plans.

14.6.2 Hazard Assessment in Planning

The European approach is mandated by the Seveso III Directive (Directive 2012/18/EU) on the control of major-accident hazards involving dangerous substances, which requires that every operator shall take all measures necessary to prevent major accidents and limit their consequences to persons and the environment. The Seveso Directive applies to two classes of establishment, classed as lower-tier and upper-tier. Upper-tier establishments have higher volumes of hazardous substances and face more onerous requirements for safety management, including:

- Preparation of Major Accident Prevention Policy (MAPP), which needs to be submitted to the national competent authority and reviewed and updated at least every five years;
- Implementation of a safety management system proportionate to the major accident hazards;
- Production of a safety report demonstrating that a safety management system is in place and that major-accident hazards have been identified and mitigated in the design, construction, operation and maintenance of the facility, and providing sufficient information to the competent authority to enable decisions to be made regarding future siting of new activities or establishments in the vicinity of the facility. The safety report also needs to be submitted to the national competent authority and reviewed and updated at least every five years.

The MAPP, safety management system and safety report must be reviewed and updated and sent to the competent authority in advance of construction or any modification that could have significant consequences for major-accident hazards.

In land use planning, it is recognised that it is uneconomic and impractical to require a completely risk free situation. There is a trade-off between accepting a level of risk and minimizing the area of land blighted by a hazardous facility. The EU Directive requires risk analysis as part of the safety report, but does not specify a procedure to be used in each case; it lays down only the general requirements. Two approaches are in use for evaluating safety:

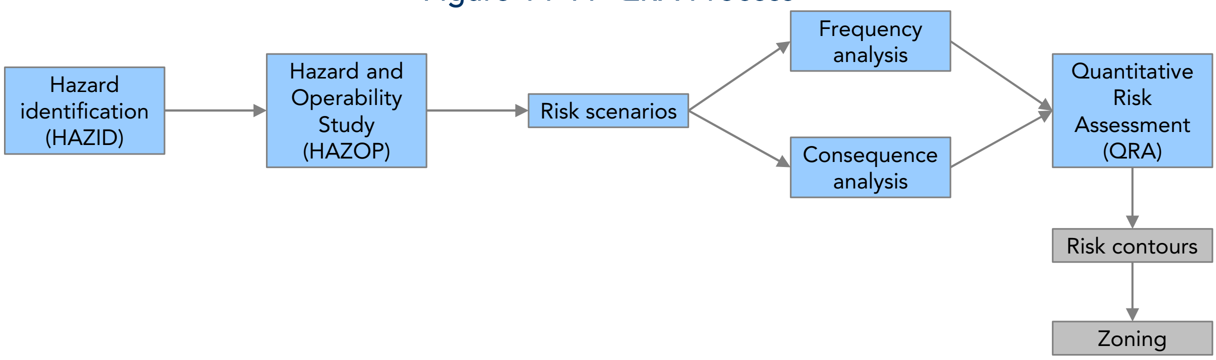
- Consequence based approach – this has been used in many countries for a long time and considers the consequences of major hazardous events and their impacts.
- Quantitative Risk Analysis or Quantitative Risk Assessment approach (QRA) – this is used extensively in the hydrocarbon industry globally and normally takes place during the design process. A QRA takes account of the probability of an event occurring and its consequences to determine the risk to people.

The Government of the Netherlands has been the pioneer in adopting a consistent methodology. The approach is described in Recommendations on land use and planning and the control of societal risk around major hazard sites, Buncefield Major Incident Investigation Board, 2008.

The QRA approach requires each company with a facility or planning a new facility that could create a major accident to undertake a QRA using a consistent computational methodology, e.g. SAFETI produced by Det Norske Veritas. The QRA is a systematic analytical technique for quantifying the risks associated with hazardous installations, based on assessing a range of foreseeable failure scenarios. The risk to an individual at a specific location is the summation of risks arising from different scenarios and is calculated as the result from the QRA. A typical approach to preparing a QRA is:

- Hazard identification
- Frequency analysis
- Consequence analysis
- Risk profile presentation

Figure 14-11 QRA Process



Risk is usually expressed in terms of fatalities per million people per year. A risk of one fatality per million people per year is shown as 10-6. Society has a different tolerance for some types of risk than for others. For example, statistics from the T&T Police Service show 164 road fatalities in 2014, i.e. a rate of 122 per million per year. Whilst this is not seen by the authorities as acceptable, it illustrates individuals' perceptions of acceptable levels of risk. For hazardous industries, however, society is generally less tolerant of risk and the Netherlands approach is to apply a risk of one per million (10-6) for the general public. This risk level is also used in several other countries, including parts of Australia and the UK. A higher level of risk may be accepted by some authorities for fatalities in the workplace. In the UK, a higher risk than 10-6 may be acceptable in the work place and even as high as 10-4 (which is less than the risk from a road accident in T&T) could be accepted providing this is mitigated to a level representing ALARP. In the Netherlands system a 10-5 risk may be allowed temporarily for less vulnerable establishments such as small offices and work places, playing fields, etc.

Societal risk is concerned with the risk that an accident may generate a number of fatalities. Society is generally averse to the risk of a large loss of life from a single incident. This would be for the government to decide but some studies suggest the probability of more than 200 to 300 fatalities should be less than one in ten thousand million (10-10).

14.6.3 Zoning

There are two approaches to zoning: risk-based analysis (as required in Europe, for example) and prescriptive (for example, as in the safety distances set out in US NFPA standards).

The current UK's Health and Safety Executive (HSE) methodology for assessing land use around an existing hazardous facility[8] uses a consequence approach of assessing the risk of an individual receiving a "dangerous dose". This is derived by Consequence Analysis and defined as something that would lead to: severe distress to all; a substantial number requiring medical attention; some requiring hospital attention; and some (about 1%) fatalities. The area around a hazardous facility is divided into three consultation zones:

- Inner zone where the risk is ten per million per year (10-5) and no permission would be granted for factories.
- Middle zone where the risk is one per million per year (10-6) and permission would normally only be granted for factories and residential houses.

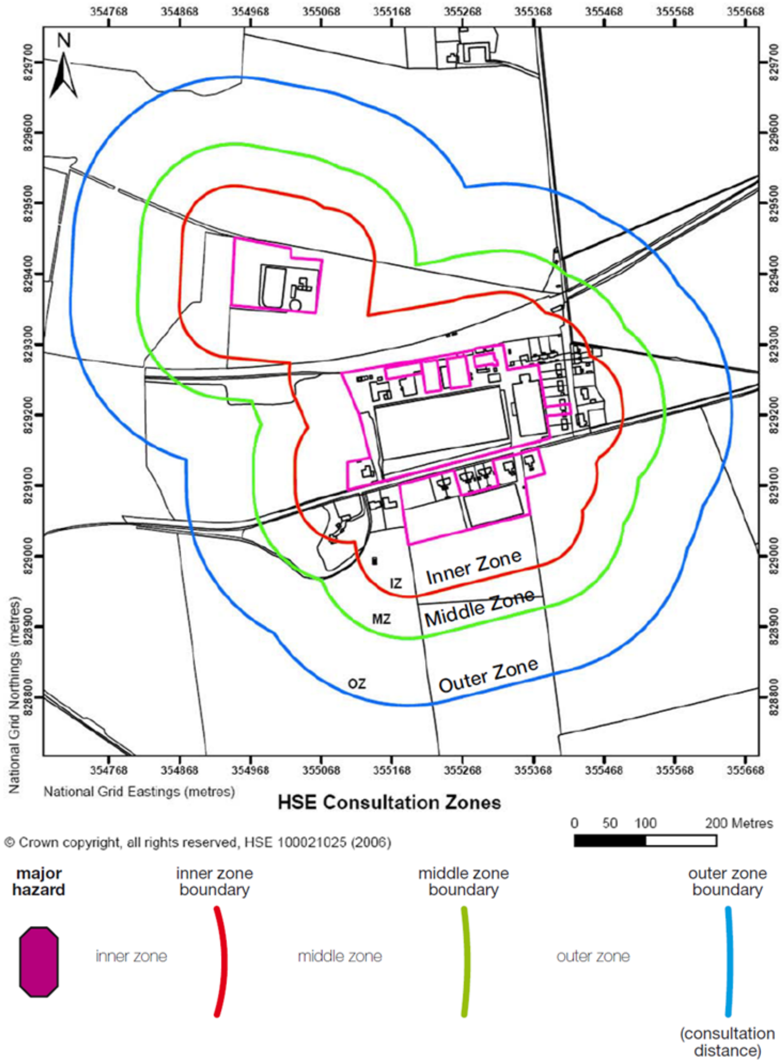
[8] HSE *Current Approach to Land Use Planning,* and HSE publication: *PADHI – HSE's Land Use Planning Methodology*, May 2011

- Outer zone where the risk is 0.3 per million per year (0.3 x 10-6) and permission would normally be granted for factories, houses and facilities for vulnerable members of society, such as primary schools and residential homes for the elderly.
- Highly sensitive facilities such as large stadia or large hospitals would only be permitted outside these zones.

Planning authorities are required to consult with the HSE regarding any developments proposed within the consultation zones that have been identified round existing facilities. The consultation zones around a major hazard site – Inner Zone, Middle Zone and Outer Zone – are illustrated in Figure 14-12 below. The zones for major hazard pipelines are the same, and run parallel to the pipeline route.

Figure 14-12 HSE Consultation Zones round Existing Major Hazard Site[9]

(source: UK HSE)



9 http://www.hse.gov.uk/landuseplanning/padhi/how-to-use-padhi/major-hazard-sites.htm

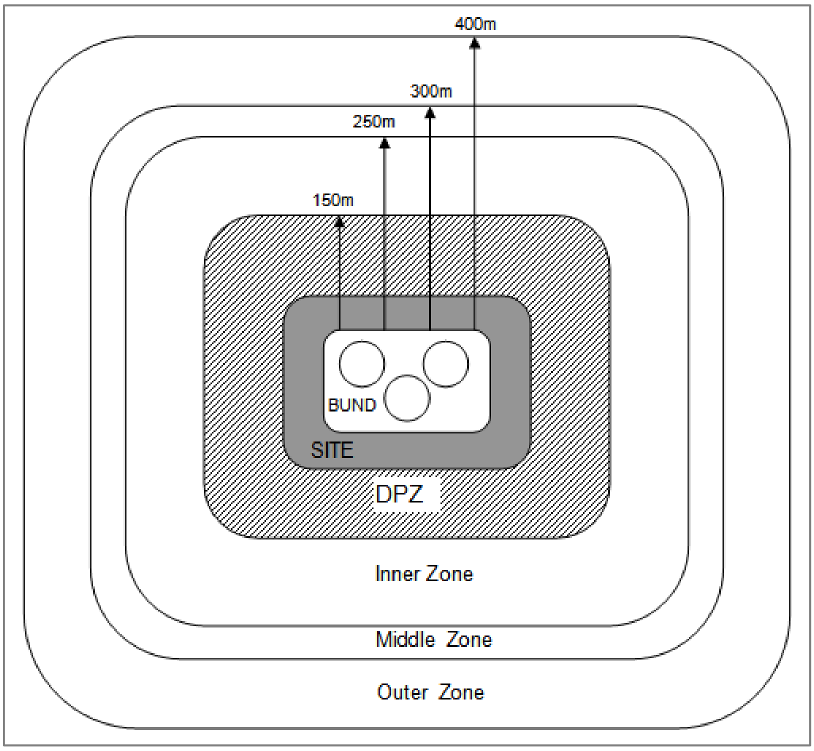
The concept of allowing factories or small offices to accept higher risk levels is based on the assumption that workers are generally alert to their surroundings and are physically fit. They are therefore able to notice a danger and move away from it. In addition, they are only normally present for part of any 24 hour period. The mapping of the zones under the HSE's Land Use Planning procedure is the responsibility of the Health and Safety Executive. The HSE determines this from information about the hazardous facility and is based on previous serious incidents and experience. The zones indicate where different types of development may be permitted, depending on their sensitivity; sensitive developments would not be permitted close to the facility.

The Buncefield incident on 11 December 2005, where there was a large fire and explosion at an oil storage facility due to overfilling a gasoline storage tank, has resulted in the UK reviewing its planning and permitting procedures for major hazard installations. The incident resulted in severe damage to office and residential buildings close to the oil storage facility; fortunately the incident occurred on a Sunday. The Buncefield Major Incident Investigation Board's 2008 report into the incident made a number of recommendations; a key one is to move to a risk based (QRA) land use planning system.

As a result of the Buncefield incident, the UK has tightened the zoning requirements around petrol (gasoline) storage (HSE – Land use planning advice around large scale petrol storage sites, SPC/TECH/GENERAL/43). This creates a Development Proximity Zone (DPZ) within the Inner Zone, which would extend 150 m from the bund of the storage facility. No development other than those not normally occupied – such as car parks or storage areas – would be permitted inside the DPZ (see Figure 14-13). The Inner Zone mentioned above would then occupy the next 100 m etc.

Figure 14-13 Land Use Planning Zones around Large Scale Gasoline/Petrol Storage

(source: UK HSE), post-Buncefield incident – note the additional Development Proximity Zone



The application of QRA methodologies is well established in the process plant industries and routinely applied during the design process. There are several QRA computer programs available to undertake the necessary computation and these incorporate databases on the probability of failure of different items of equipment. To apply either consequence or QRA approaches requires the completion of some design work to provide the data and assumptions to be fed into the models. An example of this would be the design for an LPG storage facility, which could use either conventional pressurised LPG storage spheres or mounded storage. In the case of conventional pressurised spheres, the radius of the 10-6 contour could be around 500-600 m, whereas for mounded storage it may be less than 100 m.

An important aspect of zoning is the requirement for the relevant planning authority to consult the HSE whenever development is planned within the zones identified around existing installations.

American codes are typically more prescriptive in terms of design standards and safety distances, based on good engineering practice, which removes the need for judgement on the part of developers.

14.6.4 Planning Practices in T&T

The competent authority in T&T for public safety in the context of land use planning and permitting will be the National Planning Authority (NPA). The Occupational Safety and Health Act requires that approval of the Chief Inspector (EMA) be obtained before undertaking any major construction activity, but this relates to activities onsite whereas potential impacts to people and the environment outside are managed by the NPA. The NPA is, however, required to collaborate with the EMA to determine whether significant environmental impacts are adequately avoided or mitigated by the development plan for the area or land development regulations.

Public safety from industrial activity is generally covered by planning regulations. However, Poten is not aware of any documentation on specific requirements for analysis or safety evaluation. Zoning standards in T&T recommend that heavy industries should be located “downwind of, and far from residential areas”. The Certificate of Environmental Clearance Rules 2001 (10(i)) note that an Environmental Impact Assessment (EIA) may include the following, but the emphasis here appears to be on risks to the environment rather than public safety:

- Identification of the potential hazards.
- An assessment of the level of risk that may be caused by the proposed activity.
- An account of the measures envisaged to address any environmental emergencies that may result from the activity.

No information on land zones and development plans has been identified apart from the NSDS, which identifies landscape management zones, protected areas, urban areas and growth poles. Industrial development may only be permitted at the growth poles.

It is not clear whether T&T requires consultation for development in the vicinity of existing facilities as some residential areas are close to industrial plants and storage tanks. In particular the residential areas of San Fernando are within 100-400 m of the Petrotrin refinery at Pointe-à-Pierre (Figure 14-14), residential areas of Couva are as close as 100 m to industries at Point Lisas (Figure 14-15) and residential areas of Point Fortin are 600 m from ALNG Train 3 (Figure 14-16). There is no information available about risks to the public that are in those areas, or whether consultation zones have been identified that require consultation with the TCPD (future NPA) for developments in those areas.

Figure 14-14 Proximity of Residential Areas to the Petrotrin Refinery
(source: Google Earth)

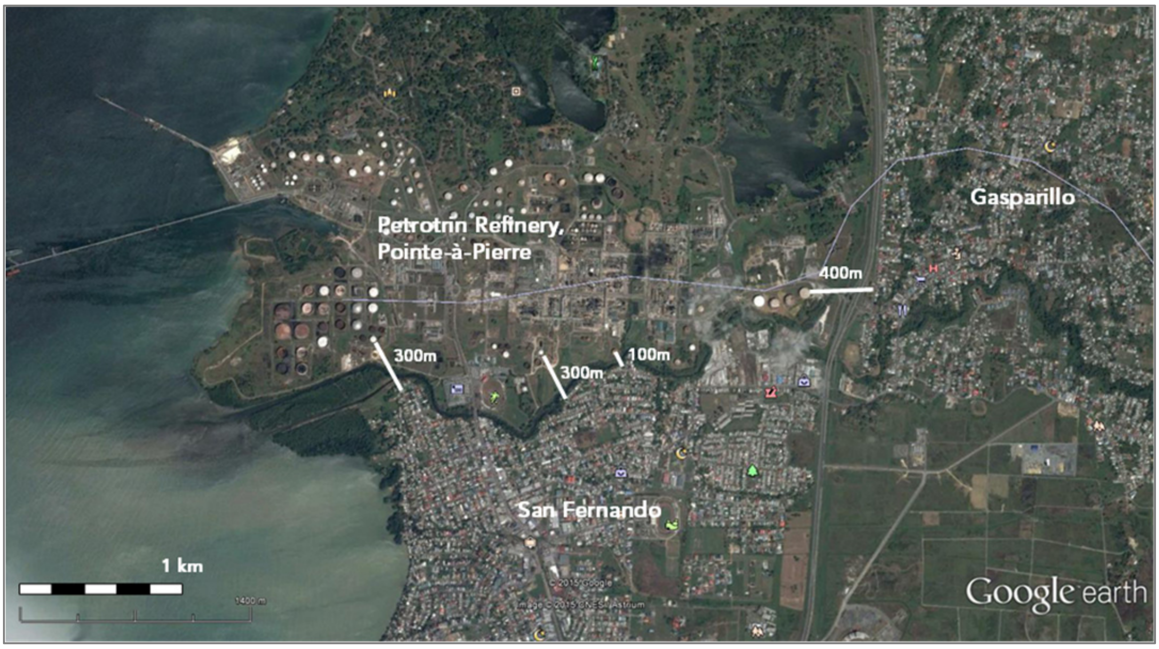


Figure 14-15 Proximity of Residential Areas to Plants at Port of Point Lisas
(source: Google Earth)

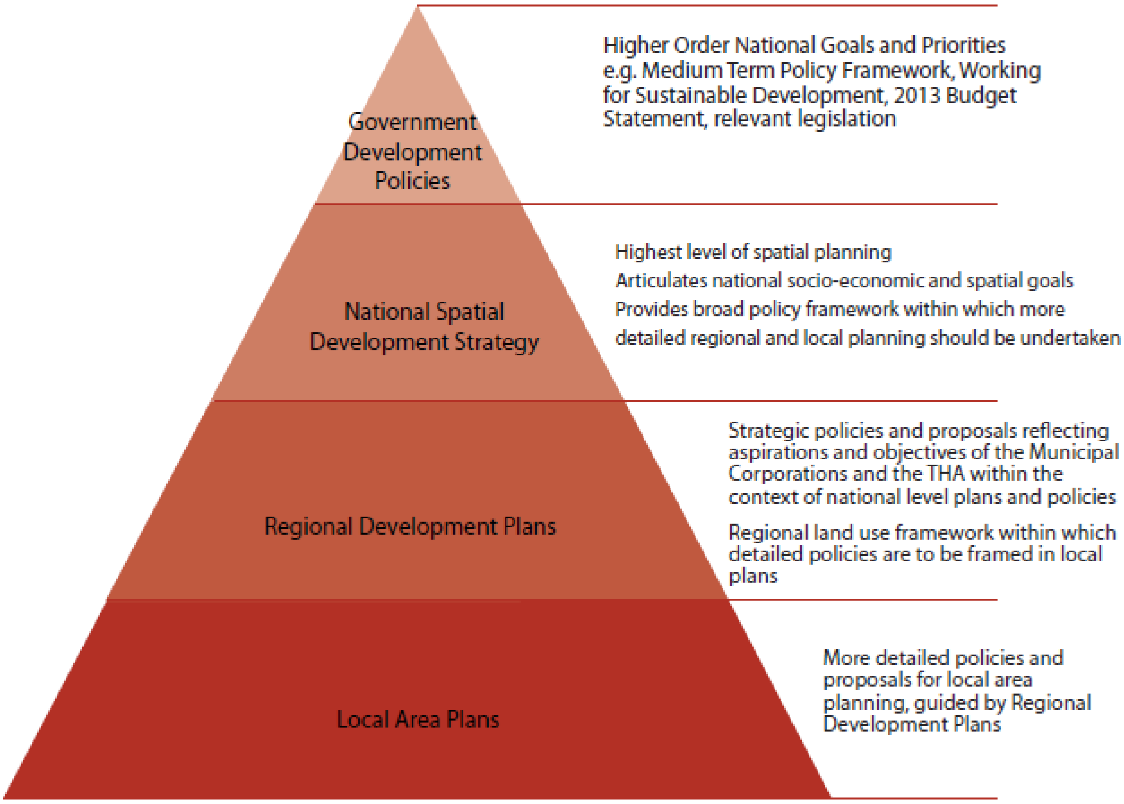
Figure 14-16 Proximity of Residential Areas to Atlantic LNG Plant at Point Fortin
(source: Google Earth)

14.6.5 National Spatial Development Strategy

The MPSD is preparing an NSDS; a draft was issued in 2014, and public consultations are ongoing. Among other objectives, the purpose of the NSDS is to provide the policy framework for regional and local planning consistent with government policies. In essence, the NSDS aims to sketch broadly the where and how of development in the country over the next 20 years. The NSDS shall come into force upon approval by Parliament.

The draft NSDS sets out the planning policy hierarchy in T&T, which describes the level of planning and policy at different levels of government, as shown in Figure 14-17.

Figure 14-17 Planning Policy Hierarchy in T&T



The NSDS includes core development policies that give effect to national objectives and high-level planning guidance for the Integrated Planning Regions (IPRs), which are discussed below. The NSDS will be implemented through regional, local and other development plans to be drawn up by the planning authorities. The NSDS and any development plans must be reviewed and updated as necessary at least every five years.

14.6.5.1 Core Development Policies

The NSDS includes 24 core development policies, of which the following six appear to be the most relevant to the Gas Master Plan:

- Policy 13: Sustainable use of natural resources - sets out principles to protect environmental resources and assets and mitigate any harmful impacts of development.
- Policy 16: Coastal and marine resource considerations – sets out a series of requirements to ensure that development in the coastal zone does not adversely impact on coastal and marine ecosystems and resources.
- Policy 17: Air quality - seeks to ensure that air quality issues and considerations are fully integrated into planning processes and decisions.
- Policy 19: Sustainable energy extraction - seeks to ensure that demand for energy and needs of energy-related industries are properly planned for.
- Policy 20: Managing hazard risk – establishes a sequential and risk assessment-based approach to spatial planning responses to potential hazards, including: flooding; landslides;

wild fire; storms and tornadoes; tsunamis and coastal hazards; earthquakes; and, hurricanes. This policy requires due account to be taken of climate change impacts.

- Policy 23: Energy efficiency - requires Planning Authorities to apply the 'energy hierarchy' (energy reduction, energy efficiency, renewable energy, clean and efficient use of non-renewables) to decisions and plan-making processes.

14.6.5.2 Planning Guidance for the Integrated Planning Regions

The Medium Term Policy Framework 2011-14 had earlier identified five "growth poles" as centres for industrial investment – Central Trinidad, the South Western Peninsula, East Port of Spain and the North-Coast and the North-East Region of Tobago. The IRPs identified by the NSDS (Figure 14-18) that are of particular interest for the Gas Master Plan lie along the western side of Trinidad where the existing gas-based industries are found, particularly:

- Central Trinidad
- San Fernando and the South
- South West Peninsula

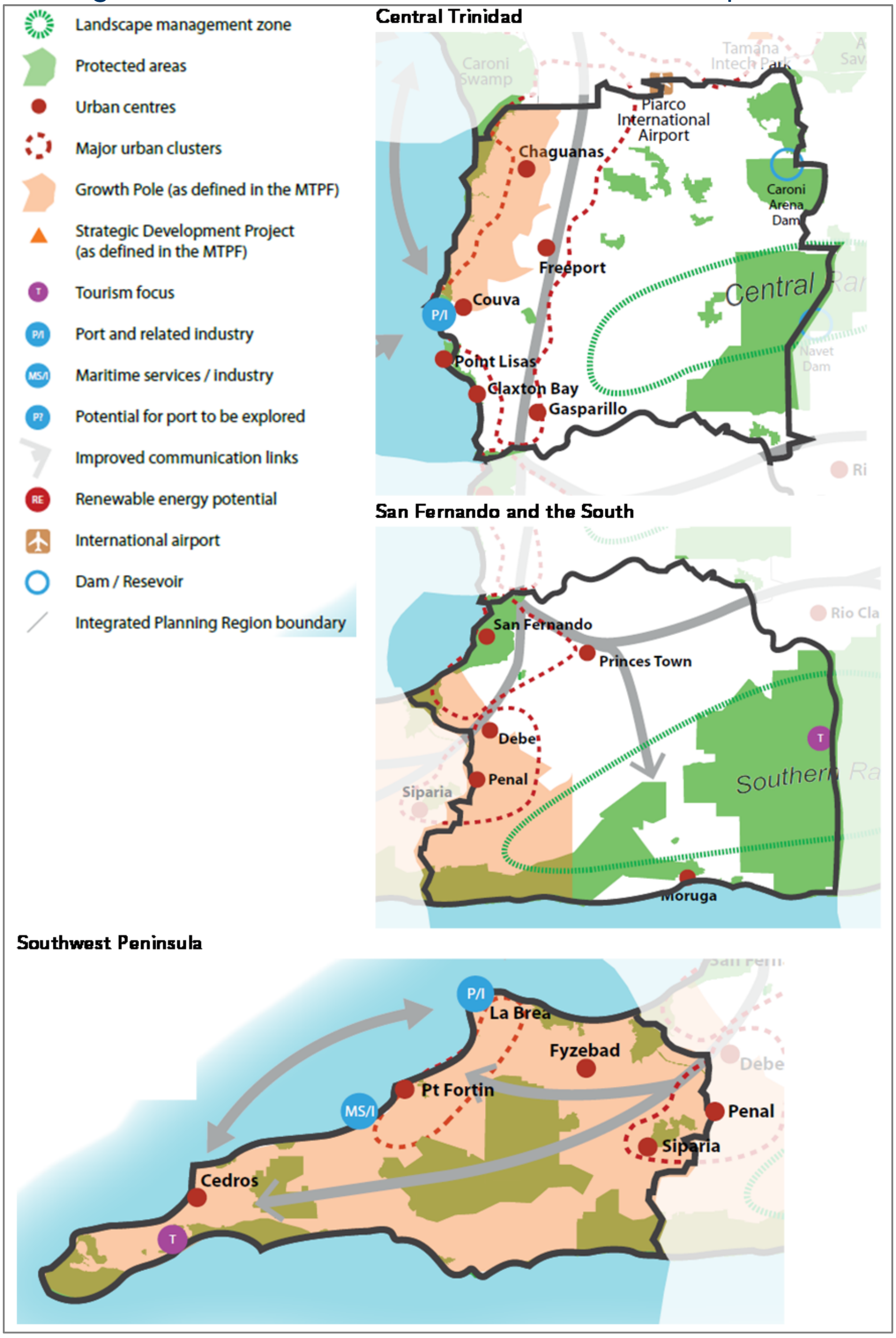
Figure 14-18 Integrated Planning Regions in Trinidad & Tobago

The development of resource-based industries and energy and service industries in all three of these IPRs is encouraged provided it "will be in harmony with natural environmental processes and will not have adverse impacts on local communities". The growth poles where industrial development would be permitted are shown in **Error! Reference source not found.**. Large-scale industrial development in the other IPRs is not specifically encouraged.

14.6.5.3 Areas for Industrial Development

The NSDS marks out potential areas for industrial development as "growth poles"; potential areas for the location of gas-based industries are shown in the figure below.

Figure 14-19 Potential Areas for Industrial Development[10]



[10] The growth poles shown in tan colour indicate areas for development

14.6.6 Locations for Gas-Based Industries

Where possible, new gas-based industries should be located close to existing gas infrastructure. The main gas-consuming locations are at Point Lisas, Pointe-à-Pierre (Petrotrin Refinery) and Point Fortin/La Brea. The most promising areas for new gas-based industries that are both within the growth poles identified and close to gas supply would appear to be north of Point Lisas, where PLNL is already located (A), and in the southwest between La Brea and ALNG at Point Fortin (B) and SW of Point Fortin (C) (see Figure 14-20). New plants must be located a safe distance from residential areas, and some resettlement may be required depending on the plot chosen.

Figure 14-20 Potential Areas for Growth of Gas-Based Industries
(source: Google Earth)

14.7 INSTITUTIONAL CAPACITY

14.7.1 MEEA

The functional organisation of MEEA consists of 7 divisions:

- Commercial Evaluation
- Contract Management
- LNG & Gas Exports
- Resource Management
- Downstream Retail & Development
- Energy Research & Planning
- Minerals

The divisions are assisted by a number of support units; HR, Legal Accounts etc. The organisation of MEEA and the allocation of roles and responsibilities within the functional areas are well structured. The most significant challenge facing MEEA is that of human capacity. MEEA has senior people in place managing the various divisions and a cohort of younger staff with 1-3 years' experience but there is a shortfall across the divisions of personnel with 5-10 years' experience. This is not a problem that is unique to MEEA but is industry wide. The issue is exacerbated at MEEA due to the poaching of staff by the industry which is able to offer higher wages etc., a situation recognised by the industry players themselves. While so ever MEEA is constrained by GORTT wage levels this will continue to be a problem.

The shortage of qualified mid-level staff manifests itself in a number of ways, lack of speed in processing licenses and decision making, and lack of effective monitoring and policing. MEEA collects a large amount of data on upstream and downstream activities but much of it appears not to be properly collated and analysed.

Given the increased burden that will be placed on MEEA, this shortage will be increasingly problematic. The need to mobilise incremental gas development on increasingly small-sized fields will put a large burden on the Commercial Evaluation and Contract & Resource Management teams. Working to improve the retention of value from the LNG sales within T&T will require significant effort.

Given the difficulties in attracting and retaining qualified personnel from the industry and the urgent nature of the assignments there will inevitably be a need to use outside expertise going forward in dealing with upstream and downstream issues. There is also the possibility of utilising secondees from the various operating companies in certain areas which are not commercially sensitive. A number of companies have indicated their willingness to support GORTT in this way.

15.1 INTRODUCTION

Local Content can be defined in a number of different forms. The two primary approaches are:

- Defining local content in terms of a measure of the economic value added in country. This is the value of labour and return on investment added to the country's GDP. This might be from foreign-owned enterprises manufacturing or providing services in country, as well as locally-owned enterprises;
- Defining local content in terms of ownership, control and financing. The 2004 paper described below has a very strong emphasis on the potential for locally-owned enterprises capturing business in the oil and gas sector outside the country. The impression is that the foreign-owned enterprises only establish in T&T as a means of servicing T&T projects and have little interest in exporting T&T services.

The World Bank has undertaken a major review of local content policies and their effects[1]. This study includes a review of several country case studies, including a short review of T&T. It covers in detail the theory behind local content policies and highlights that the oil and gas industry is one of the most difficult to achieve the backward integration into the economy that these policies are trying to achieve. The reasons for this are: the high level of value added in the industry (large economic rent and hence low inputs); the highly capital intensive nature of the industry with very specialised capital goods; the economies of scale required; and the fact that the industry is often new to a country and may not be sustained for the long term.

The World Bank report highlights some of the imperfections that a local content policy may try to mitigate against, such as the development of local learning and skills; and possible bias against local suppliers due to the long-term established relationships the oil companies have with their traditional suppliers.

The report found no evidence that there had been any attempt to analyse the cost / benefit balance for the local content policies in any country studied. The report suggested two possible tests: the Mill test which requires that the protected sector eventually survives international competition and the Bastable test which calls for the present value of the future benefits of the policy to compensate for the present costs. Section 15.3.5 below describes this policy issue. The report also highlighted that the literature showed that infant industry protection in local content policy tends to work where there was a latent comparative advantage that can be developed behind the protection.

Case Studies on Local Content can be found in Appendix M.

[1] Local Content Policies in the Oil and Gas Sector; Tordo, Warner, Manzano and Anouti; World Bank, 2013

15.2 T&T POLICY ON LOCAL CONTENT

The October 2004 Local Content & Local Participation Policy & Framework paper is the latest statement of GORTT policy and recognises that T&T has achieved approximately a 10% capture of value added in the oil & gas sector. It also states that for many aspects of the industry the cyclical and lumpy nature of project work make it difficult to sustain many of the industries needed to support the oil & gas sector if they are reliant only on capturing business in T&T. The policy therefore calls for innovation to:

- Identify and select areas for focus of local capability development.
- Identify current capability and gaps.
  - Set targets for local capability and capacity.
  - Build capability.
- Strengthen or build institutions.
- Set and maintain high standards.
- Remain dynamic (monitor change and improve).
- Regulate local content and knowledge and technology transfer - history tells us that it does not work if it is an option.
- Pick as partners companies who support this strategy and will help deliver it.
- Measure performance; report on it; learn from it; build on it.

The policy paper recognises that the traditional approach of giving preference to local suppliers if the cost, quality and timeliness of delivery of their goods and/or services are of equal quality to the international competitor has not helped build local capability, as only those who are already globally competitive will succeed. There is no opportunity to become competitive if the local operator is not given a chance to do so, learn and improve. For this reason "local capability development" will be an important part of the implementation strategy.

Recognising that not all projects, activities, goods or services can be addressed immediately nor can they all be delivered or sustained locally, the Permanent Local Content Committee (PLCC) was mandated to initially direct efforts to maximise local content and participation in the following way and in the following key areas:-

1) Define local content and participation in terms of the level of:
   - Local ownership, control and decision-making.
   - Local financing (preferential access to local finance – not just equal access).
2) Require preferential treatment of local suppliers by:
   - Ensuring that they are given preference and assurances from the principal operator, which is not deferred to primary or other contractors. These assurances will include, access, treatment and reimbursement for goods and services actually provided.
   - Addressing current barriers that prevent this from happening.
3) Focus people development in key areas that allow locals to take more value-added, analytical and decision making roles and ensure that existing regulations and processes, like the work permits, are aligned to ensure compliance with policies and strategies:

- High value-added skills
- Technical
- General management
- Design engineering
- Project management
- Seismic processing
- Human resource development
- Business strategic skills
- Leadership
- Business development
- Commercial
- Analytical
- Negotiating
- Strategy development
- Trading

4) Establish technology and business know-how with high value, consistent and sustained demand and which might be transferable to other sectors of the economy. Areas for immediate focus include:

- Fabrication
- IT support, including seismic data management and processing support
- Operations and maintenance support
- Maritime services
- Business support services, including accounting, HR services and consulting
- Financing
- Trading

5) Create and maintain databases of:

- Projects and operations work programmes, including their needs for the provision of goods and services and their scheduling.
- Local suppliers of goods and services.
- People development programmes and initiatives of the operators and their international contractors, including work permits awarded and the related commitments.
- Business development programmes and initiatives.
- The progress of activities of ”in country“ operators, state-owned companies and agencies and their contractors, including their:
  (i) Local content and participation policies, strategies and initiatives.
  (ii) Targets, benchmarks and performance metrics.
- Appropriate legislation, regulations and contracts.

In recognition of the importance of local value added to national development, GORTT’s intention was to ensure that the PLCC has the necessary resources (human, financial and technological) to properly deliver on its mandate. The PLCC is responsible for:

- Updating the local content and participation policy, as required;
- Developing specific subsidiary policies and strategies, to ensure the transfer of technology and know-how to improve local skills, businesses and the capital market;

- Ensuring compliance with these policies; and
- Reporting to the Minister of Energy and Energy Affairs and the Cabinet, as appropriate.

The World Bank report on local content, previously cited, reports on implementation of the policy and found that it "remains piecemeal". As apparently stated by MEEA the main challenges are:

- The absence of regulatory measures to ensure mandatory compliance with objectives local for participation in the energy sector.
- The development of institutional capacity for the implementation, monitoring and auditing of local content targets.
- State support for programs to encourage research and development, technology transfer, skills development and business incubation in the energy sector.
- Mobilisation of local financing to support the services sector/
- The existence of bilateral treaties with other states, which seek to discourage the implementation of a local content program.

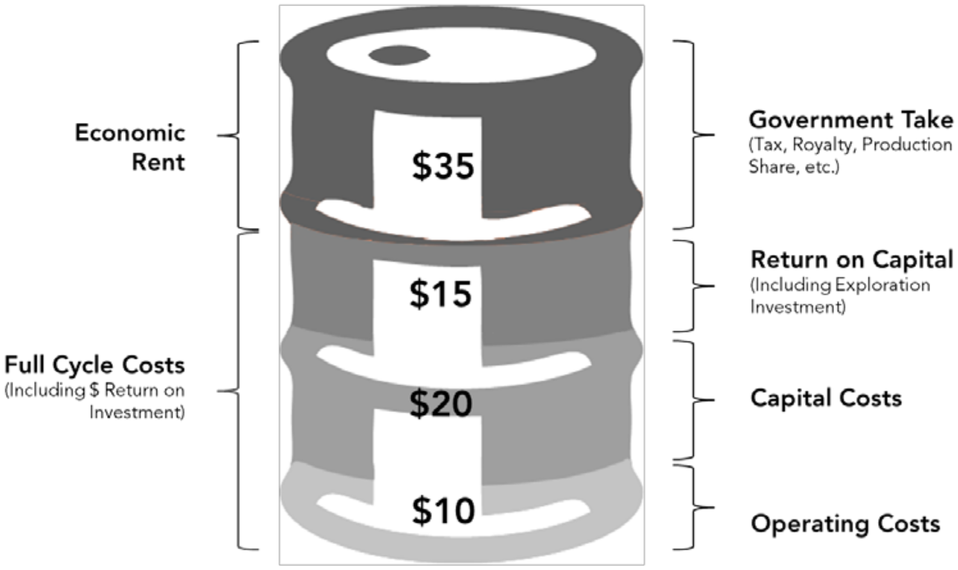
Overall, local content policies are not integrated in GORTT's regulatory activities of the sector. More specifically, there is an absence of a well-defined monitoring and measurement system.

15.3 ECONOMIC RATIONALE FOR A LOCAL CONTENT POLICY

15.3.1 Economics of Hydrocarbon Production

Oil and gas in the ground is a national capital asset. If exploited efficiently, the income produced from the hydrocarbon is greater than the fair cost of the capital and operating costs the oil company (state owned or private sector) has used to produce the hydrocarbon. This additional value or economic rent, should be captured by the host government on behalf of the nation through an oil and gas fiscal industry regime and represents the value of the resource.

Figure 15-1 "Efficient" Division of Value of a Barrel of Oil Produced



$ numbers are purely for illustration

Some of the costs of producing the hydrocarbon are most efficiently spent in the country of the producer if they either improve or do not reduce the economic rent. Costs spent in country have a greater impact on domestic economy than money spent on imports. Local expenditures results in the classic multiplier effect within the economy yielding a greater impact on GDP. It also creates employment and this in turn builds stakeholders within the economy that have an interest in a healthy hydrocarbon industry. Without the support of these stakeholders, the dominant political voice may be from those who see only the adverse impacts of the industry. It then becomes difficult for politicians to support the industry.

15.3.2 Multiplier Effects

The value of multiplier effects on the economy of a country will depend on the extent to which the country's other industries and service providers can provide the inputs the hydrocarbon industry needs. A small country with no relevant industrial base may have a very low multiplier – perhaps only a little above one. In this circumstance, the labour required flies in when needed and all the materials required for the industry are imported, perhaps even food for the workers. At the other extreme, a country such as the USA has a very sophisticated economy and according to recent surveys has a multiplier of between

2.2 and 2.3 in value added terms and 4.2 to 4.5 in terms an employment multiplier (i.e. in the USA one new job directly in the oil and gas industry adds over three more jobs in support industries)[2].

15.3.3 Export Earnings

The multiplier effect can generate significant returns from local content but the much larger win for a country is to create an industry that exports goods or services overseas. The benefits then become much greater and can justify significant investment in developing the industry. T&T's 2004 policy document places heavy emphasis on this issue, particularly from the point of view of creating locally owned and controlled companies that would seek such exports.

The benefits to an economy of local content are very great – the hard part is to determine and implement government policies to encourage local content and therefore grow the economy more than it would have done without intervention

15.3.4 Impact of Globalisation of Industries

As all industries in the world have globalised, the economies of scale and the huge investment needed to develop new products and manufacture them efficiently has meant that for every product there emerges a small group of companies with the scale necessary to be efficient and to compete globally. This is true for the oil and gas support industry where in each sub-sector there may be less than ten companies who can compete efficiently. A country that decides to produce everything locally will find that the cost of the locally produced equipment or services is much greater than the most efficient company globally. The economies of scale and the accumulated experience of the global company allow it to be much more efficient.

Modern industries are also not completely dependent on the micro-economics of one enterprise. The work of Porter [3] has highlighted the importance of industry clusters as an important factor in understanding how companies gain competitive advantage. An industry cluster has a critical mass of companies and supporting infrastructure, such as universities, that feed on each other's innovations to efficiently and continuously develop new products or services.

The desired state for an industry to achieve efficiency is that it is sufficient in scale and accumulated learning that it is among the global leaders in its sub-sector and that it has the benefit of a supporting cluster of associated facilities (e.g. universities) and supporting industries. It is very hard to achieve this without serving the global rather than just the domestic market.

A country that decides to be self-sufficient in all aspects of the industries that support hydrocarbon production will increase the costs of the industry. The only place that this cost can be recovered from is by reducing the economic rent generated. The end result is that there will be less oil and gas that can be economically produced and what is produced will generate less tax revenue. To reach a situation where all or the majority of equipment and services is produced domestically would require a very large economy. For smaller economies, attempting to reach too high a level of local content will result in less

[2] The Economic Impacts of the Oil and Natural Gas Industry on the U.S. Economy in 2009: Employment, Labor Income and Value Added – prepared by PricewaterhouseCoopers, 2011
The Contributions of the Natural Gas Industry to the US National and State Economies, prepared by I H S Global Insights for America's Natural Gas Alliance, 2009

[3] The Competitive Advantage of Nations Michael Porter (1990)

competition among suppliers; higher costs; a constrained oil and gas sector and reduced government take from what is produced. (This is the current situation in Brazil, for example).

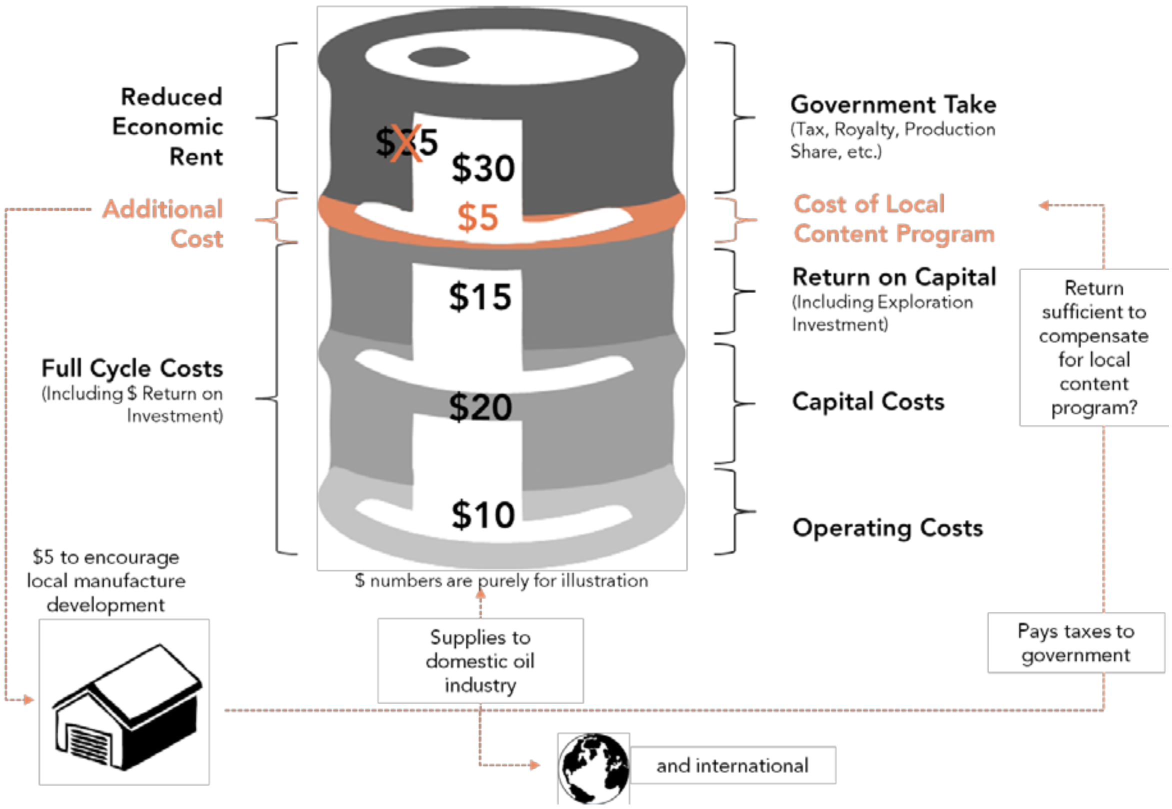
15.3.5 Government Policy Options

It is easy to see the advantages of local content and the disadvantages of forcing high levels of local content. The challenge is to find policies simultaneously generating an economic optimum as well as creating the desired local content effect.

Governments around the world have implemented various policies in an attempt to increase local content from the oil and gas sector. We have divided these into three approaches:

- Exhortation – e.g. setting targets for the industry but with no explicit consequences for failure to achieve these.
- Mandatory – e.g. setting percentages of local content or prohibiting the import of certain goods and services
- Promotion – e.g. establishing relevant education and training, industry promotion and training to assist local companies in bidding for work

Figure 15-2 Effect of Local Content Program Imposing Extra Cost and Generating a Return



If the fiscal regime for the oil and gas industry has been established correctly, then the effect of almost any policy action is to impose a cost on the industry that then reduces the government take. If the industry could accommodate the extra cost, it would mean that the fiscal regime had failed to extract the optimal take – hopefully this is not the case and it should not be assumed it is. The reduction in government take may be a rational investment for a government if it later leads to a domestic industry that adds more value and ends up repaying the cost of the initial local content policy.

15.3.6 International Commitments

Governments have generally recognised that international trade will benefit their economy. Most countries have entered into agreements to encourage international trade and therefore prohibit discrimination in favour of their own domestic industries. These commitments preclude some of the policy options that might be chosen:

- T&T has been a member of the World Trade Organization (WTO) since 1 March 1995 and a signatory of the General Agreement on Tariffs and Trade (GATT) since 23 October 1962. These commitments limit options for protecting local industry.
- T&T joined the Caribbean Community (CARICOM) on 1 August 1973. In addition to commitments on free trade, CARICOM also has commitments to free movement of university graduates.

Poten understands that upon the coming into force of the Marrakech Final Act establishing the WTO, all member states had to notify their existing Trade-Related Investment Measures (TRIMs) to the WTO TRIMs Council. For developing countries, a five year transition period was granted after which all TRIMs were supposed to be phased out. For most developing countries, the transition period expired in 2000 and this meant that any TRIMs existing after the transition period would have to be subjected to the disciplines of the TRIMs Agreement. The basic criterion would be the extent to which the local content policy potentially alters the balance of competition between foreign and domestic products.

Local content legislation therefore must be carefully designed to ensure that it is compliant with TRIMS-requirements and also not violate the General Agreement on Trade in Services (GATS) by according preferences to the procurement of local services over similar foreign services or service providers.

The commitments made by GORTT to free trade appear to preclude many of the actions some governments have used for increasing local content such as:

- Prohibitions on the importation of certain goods.
- Tariffs in excess of those agreed under WTO.
- Mandatory levels of local content to be achieved on projects.
- In the case of CARICOM, preference for the employment of nationals in graduate level positions.

Some countries have successfully used non-tariff barriers to protect domestic industry, such as technical standards that are unique to the country. These are more difficult to implement in the oil and gas industry. The industry has standards that have been developed to embody years of experience and that have been shown to create the conditions for safe operations. International companies will not be willing to accept the risk of adopting unique domestic standards over these. The possibility of prejudicing safe operations is not acceptable to them.

15.4 MEASURING LOCAL CONTENT

If a government intends to encourage local content, the first step should be to introduce measures that generate data on the extent of local content in the oil and gas sector. Without a data benchmark it is not possible to ascertain if the policy is successful and if the investment being made is generating an acceptable return.

The T&T Local Content & Local Participation Policy & Framework document of 2004 has several excellent requirements for reporting on local content development. These will be very valuable in developing the policy further. At the high level the policy requires:

- "Measure performance; report on it; learn from it; build on it."

Elsewhere in the policy, it states that to ensure the delivery of maximum local value added there must be:

- "Measuring and reporting on the performance of operators in the sector;
- Periodically comparing the local content and participation performance amongst operators, between projects and operations with other countries, to establish benchmarks, targets and opportunities for improvement and for the transfer of best practices."

15.5 T&T ACHIEVEMENTS IN LOCAL CONTENT

15.5.1 Interviews with Industry Participants

Trinidad is not new to the oil and gas industry. It has over 100 years of oil production and processing and during this time, local companies have developed to service the needs of the industry. The industry has developed an excellent venue for exchanging ideas and information between the industry and its service sector, the Energy Chamber. The Energy Chamber provides a forum for the service sector to make its views known and also organises regular meetings where the service sector can meet the local oil company executives. This is an example of good practice in local content that many other countries should note and follow. Like all such organisation its success is entirely dependent on the efforts of its staff and members, who seem to realise that they can only expect to receive benefits from such an organisation if they are prepared to put the effort into it. The comments below are based on several meetings and are reproduced under *Chatham House Rules*, i.e. they are not directly attributed. The respondents are a mixture of locally owned companies, foreign owned companies and oil and gas companies:

- Trinidad has many major achievements that are worth noting and celebrating:
    - As a result of the Energy Chamber’s work, there is an industry wide HSE prequalification program that allows local firms to meet the requirements of the oil companies without having to separately prequalify for each company.
    - Most of the service sector companies have certified their quality systems to ISO 9000 and meet oil company and major contractors’ requirements.
    - Trinidad’s education system and the maturity of the industry has produced well qualified staff, both graduate and technician. Most foreign firms are able to achieve very high percentage of local staff vs expats – e.g. Baker Hughes claims 98%. Long established oil companies claim that their numbers of expatriate staff in Trinidad are balanced by the numbers of highly qualified Trinidadians working abroad.

- Local Content Policy should be reformulated to emphasize that T&T Value Added is the critical measure of success. Both the service sector companies and the International Oil Companies believed this was the most important change that the government should effect.

  The service companies support this change as they believe the current policy results in “nameplate companies / agents” taking contracts on behalf of foreign companies. It does not assist genuine Trinidadian companies who employ local workers and capital.

  The International Oil Companies dislike this requirement for similar reasons and because it becomes a “tax” that must be paid – i.e. the agent commission.

- The Local Content Policy should also place a value on competences being added to Trinidad’s stock of intellectual capital. – e.g. is technology being transferred to Trinidad?, is this supporting the strategic objectives of supporting future business, particularly one that can be exported? The participants felt that the strategy for developing expertise needed in the future should be clarified. Deep water technology was a significant concern. Everyone recognised that, for now, this expertise is in Houston. The issue is how does T&T position itself for the future?

- Emphasis should be on services and not manufacturing. The companies all recognise that with few exceptions, manufacturing was difficult for locally owned companies, given the need to be globally competitive.

- Some disagreement among companies on the level of expatriates present in the industry. Everyone recognizes that they are needed to transfer in new technologies and to maintain standards across international oil companies. However, many felt that work permits were being issued without a plan for technology transfer.
- Education is a key service industry. The Ministry of Tertiary Education and Skills Training is responsible in Trinidad & Tobago and all the universities and technical colleges operate as "agencies" under control of the ministry. Tertiary education is free to citizens. T&T has strengths in education which are not being aggressively marketed. It could be become a global centre for English language oil and gas technical training and university level education.
- The 'education industry' was also believed to be not looking far enough ahead to prepare for the future needs of the industry.
- Business and entrepreneurial education were felt to be weak – It was pointed out that the Business School had an MBA in sustainable energy but not oil and gas.
- Tenders should be published to allow local companies to bid – better if there is advance notice. The Energy Chamber provides a venue for this to happen but it was felt that the oil companies need to put more effort into helping the local companies prepare themselves to bid for new areas of work by giving better advance notice.
- General belief from the service sector companies that more information on local content performance should be put in the public domain. Disappointed that Local Content Committee has not met since Mr DaSilva retired from the Ministry and the local content unit there has been less active.
- All believed that the government was not doing enough to lower businesses costs of operating in Trinidad by investing in infrastructure. Roads to industrial areas were of a poor standard and the Labidco Industrial area, although a good idea for providing a major asset for local contractors to use, was not being run on commercial basis – i.e. it was not able to reduce the rent it charged during periods of low activity to help contractors win work and bring this to Trinidad.
- Work load even in the service sector can be very lumpy – industry needs to do what they can to avoid this but all recognize that with the integration of upstream and downstream gas businesses and the need to synchronise major turnarounds, that this may be unavoidable. The service sector cannot manage its workload unless it exports. Using the non-oil and gas construction sector as a swing resource is not ideal.
- Service sector companies would like to see more support from T&T Government missions in countries that they are trying to export to. Africa was highlighted as a region that firms hoped that they could break into but found difficult without on the ground support from a local trade attaché.
- Everyone had hopes that Trinidad could capitalise on its strength and export services to the regional market, i.e. Guyana, Suriname and Venezuela. However, everyone also recognized that the US Gulf Coast was not far away and that this was the global resource base for oil and gas and a highly efficient set of competitors.
- Serious concern among the service sector companies to the entry of Chinese contractors into the country. There was a general belief that these companies had been very self-sufficient in their overseas operations and reluctant to use local resources.

- It was suggested that T&T should consider a sister city approach (referred to as "twin towns" in Europe where it originated)[4]. This could be used to say twin with a city, perhaps in the USA that had companies with the technology that T&T needed to develop for the next stage of development of the oil industry.
- Global supplier alliances between major oil companies and services companies were a major problem for local companies. Many oil and gas companies, in the interests of cutting costs in their procurement processes, had entered into these alliances. However, they cut out local suppliers or relegated them to being managed by international services companies. In response, the oil companies believed that they had provisions in their alliance agreements to encourage these alliance companies to use local resources.
- Atlantic LNG was the origin of Trinidad's National Energy Skills Center (NESC), which was established in 1997 with its primary objective being the building of the human resource capital of Trinidad and Tobago. It was envisaged then, as the solution to the need for a premier training provider to lead national training initiatives. This vision was based on the projected demands for certified craftsmen, arising out of the growth in the energy sector and consequently, the construction and related industries. The NESC was established to be an autonomous training provider; linking State, Industry and International Institutions and has to date trained over twelve thousand (20,000) craftsmen and over 120,000 persons in Information and Communications Technology. LNG Train 4 was cited by many as the best example of good practice in local content on a major project. The keys to the success were a well thought out plan for local procurement that did not add to costs. Perhaps the advantage this project had was that it was the fourth train in quick succession using the same EPC Contractor who had built experience and confidence in T&T resources.
- Financial support to the services industry was believed to be an issue. Banks were not experienced in trade finance nor in lending to businesses. An example was given that local companies could not bid for five year charters for supply boats due to their inability to raise finance despite the fact that the loan would be secured against the high quality charter from an international oil company.
- Some concern that the national Trinidad oil and gas companies were not good at evaluating the competences of foreign bidders for work and accepted at face value claims by bidders that could easily be shown to be untrue.
- The local firms were disappointed that no T&T major Engineering, Procurement and Construction (EPC) contractor had developed. Several of the major international EPC firms had run offices in Trinidad but these shrank when there were no new major projects and were not used as an international resource by these firms.

15.5.2 Development of the Energy Services Sector

The discussion about "Local Content", although written to cover both manufacturing industry and the services sector is predominantly concerned with the services sector.

Opportunities to develop a manufacturing industry linked to the Oil and Gas sector are not obvious in Trinidad & Tobago. The domestic oil and gas industry is not sufficiently large to support a manufacturing industry orientated to its needs beyond the usual import substitution industries that can

[4] See http://en.wikipedia.org/wiki/Twin_towns_and_sister_cities or for the US organization http://www.sister-cities.org/

also gain scale by serving Trinidad and Tobago beyond the sector, such as cement, steelwork fabrication and other building materials. It is feasible for manufacturing industries to develop and typical scenarios where this might happen would be around a particular technical development where Trinidad & Tobago was a proving ground for the technology.

The main strength of T&T's industries serving the oil and gas industry is the service sector and some aspects of this are described below:

15.5.2.1 Engineering, Procurement and Construction (EPC).

There are only a relatively few – around ten major EPC companies operating globally. Several of these, such as Bechtel, Fluor and Worley Parsons have at various times established offices in Trinidad. These have been to service major projects. None appear to have made the difficult transition to a mainstream international EPC contractor. For example, Bechtel created ABT a 50/50 joint venture with a Trinidadian company Asset & Risk Engineering Group (ARE). This was originally established for Atlantic LNG Train 4. The EPC companies in Trinidad continue to serve mainly small operations phase projects, debottlenecking etc on the various plants in Trinidad.

There are very few examples of new, international EPC companies being created. The only major example is Petrofac, who are now a UK headquartered company with the capacity to execute projects of $3 billion. Petrofac started to develop in 1991, when the key managers created a new international operation in Sharjah, UAE out of a small US modular plant contractor. Using Sharjah as a base and recruiting low cost engineering resources, the company grew strongly on work in the Middle East. In 2005, the company was floated on the UK stock market with a capitalisation of $1.3 bn. Petrofac's key initial success factors were the size of the Middle East market, their management team, who had previous experience in major contractors, and that they were one of the few locally owned and managed companies with significant and competitively priced engineering resources in the Middle East. Their competition was mainly from the mainstream contractors who executed work from their home offices.

Emulating Petrofac's growth in Trinidad is not easy. Trinidad and the region are much smaller markets than the Middle East. Trinidad when compared to using Third Country Nationals in the Middle East; Trinidad is a relatively high wage economy. Trinidad would also need the entrepreneurial owners ready to aggressively grow the business over a decade competing for all the regional business. While the latter factor is feasible, the size of the market and Trinidad's cost base appear to make it difficult for someone to create another Petrofac.

Another route to growing an EPC business is to become the base for one of the major international EPC companies. These select their locations based on:

- Availability of many highly qualified and experienced engineers that clients may be willing to pay a premium for – Houston, London and Paris fall into this category.
- Proximity to a large domestic or regional market for projects and moderate cost base – The Middle East and Malaysia fall into this category.
- Finally the main detail engineering for international EPC companies is done in locations where wage rates for graduate engineers are low. India and China are the main locations that have been developed by major contractors for bulk detail engineering.

Trinidad appears closest to the middle category but does not offer the size of market that the successful locations offer. Reviewing the likely future plans for Trinidad, these are mainly going to be upstream projects. The onshore gas utilisation plants that represent the larger projects that an EPC contractor would be interested in are going to be rare. The industry has naturally reached a state where the gas production projects are running down and need to be replaced by new projects just to keep the existing industries operating. Building new gas industries seems unlikely in this environment of increasing gas scarcity.

Trinidad and Tobago also suffers from the geographic proximity of Houston. Houston is the World's largest concentration of EPC companies and resources. It is very tough for a Trinidad based EPC company to compete with Houston based firms for work in Trinidad and even harder for the region in general.

The conclusion on the prospects for the development of this sector is that it will continue at the scale it is now – i.e. mainly undertaking small debottlenecking type projects.

15.5.2.2 Oilfield services

Trinidad will need to find new gas production and will need to continue to drill to maintain its industries. The Oilfield services industry has developed in Trinidad with companies such as Baker Hughes maintaining a large presence in the country supporting drilling and production.

The industry appears to have a very high local value added that has been created from its mature position. The key development area that requires attention is the development of deep water expertise. Trinidad appears to have several opportunities to start production from deep water but most of this expertise currently resides in Houston based companies. The major international companies that have established bases in Trinidad have this expertise. A key target then in sanctioning these new projects will be to ensure that these companies transfer the technology to their Trinidad based operations and not service these from Houston, e.g:

- Work permits are tied to efforts to train Trinidad based staff and transfer technology
- Trinidad & Tobago value added is the key measure of Local Content – this will also encourage technology transfer to Trinidad based staff in order to score highly on this metric.

Managing this process of encouraging the technology transfer of deep water expertise, will be important in increasing the pace of learning and Local Content development. The knowledge also appears that it should be applicable in other regional markets such as Guyana.

15.5.2.3 Education and training

The Tertiary Education and Skills Training sector in Trinidad & Tobago is already well developed. It has often grown up to meet specific project needs in Trinidad. It also largely falls under the control of the Ministry of Tertiary Education and Skills Training, with the institutions operating as agencies under this Ministry.

Education and Skills Training for the Oil and Gas sector should be regarded as a key national core competence. Trinidad has a natural advantage over many other countries in the region. It is English speaking, has a well respected university system and a long established oil and gas industry. It should be ready for transitioning into a more aggressive commercial education sector charging significant fees to foreign students in the way US and UK institutions operate and market overseas.

This will require some re-thinking of how the Tertiary education sector operates in Trinidad. It may be hard to encourage the entrepreneurial approach as an agency of a Ministry. This reorientation requires political level decisions both of the institutions and potentially of the immigration rules to allow easy entry of students.

15.5.3 Summary of the Status of T & T Local Content

Many aspects of local content in the oil and gas sector in Trinidad & Tobago are internationally best practice and a good example for others to follow. These include:

- An active Energy Chamber bringing the service sector and oil and gas companies together.
- An education system working in the English language and producing quality graduates and technicians
- A HSE and Quality Management prequalification system that allows local companies to comply with otherwise burdensome different prequalification systems from oil companies.
- A long history in the industry that has allowed experience to develop
- Government provided common infrastructure such as the Labidco facility for fabricating offshore platforms
- A vibrant private sector services industry that comprises a mix of locally owned and foreign owned firms.

The areas where it appears that improvements could take place include:

- Loss of attention to the issues of local content by the Ministry. The 2004 policy placed the Prime Minister in charge of this issue. This was perhaps unrealistic to commit future Prime Ministers to this role and we understand that for a while, one official in the Ministry was effective in pushing the issue but he retired several years ago. Since then, there may not have been sufficient stability and visibility in this role.
- Measuring local content, in terms of the address the purchase order was sent to, is not a popular policy among the oil and gas companies and the service sector companies. It does produce very high percentages for local content procurement during the operational phases of a project, so may be good for headlines. There seems to be universal agreement that the policy objective should be local value added.
- Trinidad has a number of separate Ministries and institutions that need to be brought into the long term planning for the oil and gas sector. Many of the training initiatives have been well received by the industry but the concern is that these have been good at responding to needs when they are obvious, but are not anticipating future needs.
- Educating foreign nationals in T&T’s educational institutions is a valid and valuable export business and should be regarded as part of the oil services sector. The USA and UK are examples of countries that have aggressively expanded tertiary education as an export business. In both cases, the universities are either private sector or semi-autonomous and retain the income received from the foreign students. T&T may find it difficult to emulate these countries, without a major reform of the management of tertiary education. This is outside the scope of this document, but developing oil and gas education appears to be a valid service sector export that could be developed.
- The entry of local companies into offering oil and gas industry service boats appears a valid area for development. This business is competitive but if it initially concentrated on T&T only, where a local company would have a competitive advantage in terms of manning and

maintenance of the vessels, it appears that it could be viable. It is unlikely that this could be set up by relying on local banks – they do not have the experience of ship financing and may not have access to low cost funds to on-lend. A better solution would be for the local company to seek help from specialist shipbrokers to set up the deal. The shipbroker would have relations with shipyards and with the specialist US, UK and Norwegian based banks that often fund ships. Ship financing is relatively low cost, since unless the ship is highly specialized, it can always be seized in the event of a default, thereby lowering the bank's risks.

15.6 RECOMMENDED POLICY FOR ENHANCING LOCAL CONTENT AND COSTS

15.6.1 Recommended Policy Changes

The key policy change is to change the criterion for Local Content measurement and reporting to "T&T Value Added".

The secondary criteria should be to report the extent that a particular procurement supports the development of new skills and technologies in T&T.

TO the extent that commercial confidentiality allows, the 'local content' performance of individual Oil and Gas Companies and the industry in general should be made public.

An obligation should be placed on the main industry participants holding PSCs and concessions to publish their forward "vision" of future plans for developing oil and gas projects over the next ten years. It is recognised that this would be non-binding but it would help the oil and gas industry service sector with their planning and ensure that Trinidad based companies do not miss business because of impossibly short timescales to prepare and develop skills.

Education should be thought of as a key export opportunity for Trinidad and should be explicitly added to the industries targets.

15.6.2 Implementing the Policy Changes

To help implement these changes, the Ministry of Energy and Energy Affairs needs to -ensure that the role of coordinating Local Content is with an official that has been given sufficient seniority to achieve the objectives and is also kept in the position long enough to be effective.

Measuring Local Value Added, which is the recommended metric for monitoring Local Content, is not as easy as the current system of recording the domicile of the vendor. The Oil and Gas companies will have to be relied on for the quality of this data and they in turn will be relying on their vendor to advise the local content. The Local Value Added for each company in Trinidad may already be reported in their annual audited accounts. In the absence of an audit for each new project, the average level of Local Value Added could be reported back to the Oil and Gas companies when the goods and services are invoiced.

Improving the visibility of local content performance is a key improvement that could be made. The Consultant recommends that as far as reasonably practical, data on each company's performance should be placed in the public domain, together with a brief commentary to explain the figures. The commentary is important as in some years, an Oil & Gas company may be executing a particular project that requires a large input of imported manufactured goods. Reporting from companies on their historic Local Content Value Added should be on the agenda during negotiations for future Production Plans, PSCs etc.

The forward view provided by each company would assist Trinidad based companies in developing their skills and resources. Deep water is clearly an issue on the horizon but without some information on likely timescales and the size of projects it is hard for Service Sector companies to plan, train and invest ready for this business. If they do not invest just in time, then the contracts will be taken by Houston based resources. If they invest too early, then they will waste money.

15.6.3 Local Skills Gaps/ Training

Two key themes for improving the already excellent training offered in Trinidad were suggested:

- Business education orientated to the oil and gas industry seems a logical add on to the curriculum of say the Arthur Lok Jack Graduate School of Business. Business education training in the Oil and Gas industry is a growing business internationally and Trinidad has the capability to develop a reputation in this area.
- Deepwater Technology is the other logical concern, given the probability that production is going to move to these areas. This area will mainly have to be dealt with by the Oilfield Services companies. They have the expertise elsewhere in their organisations and should be happy to transfer the expertise to Trinidad once the Oil and Gas companies demonstrate that there are going to implement deepwater projects.

15.6.4 Vision for Local Content – Benefits

The value of implementing the changes outlined above is difficult to quantify. Poten suggests that the following are targets for the benefits from the policy changes:

- Transition to measuring Local Value Added and ensuring that a sufficiently senior person is appointed in the MEEA to champion local content. The initial year will provide the baseline for the value being generated in the T&T economy. The target from then on would be to show a continuous improvement in Local Value Added as a proportion of total industry spend – target 10% per year growth.
- Export of education services – An appropriate medium term aim, subject to GORTT approval would be to generate say 1000 student places each year on short and full time courses generating an average of $10,000 of fees and at least $10,000 each direct spend in the T&T economy, i.e. a total direct benefit of $20 million. This should be achievable with minimal investment in facilities.
- Two Services Companies ready by 2017 to offer support to Deepwater exploration and appraisal activities using trained T&T staff.

16.1 INTRODUCTION

In "Our Common Future" (the Brundtland Report to the United Nations, 1987) sustainable development is defined as development that meets the needs of the present without compromising the ability of future generations to meet their own needs. Sustainable development has numerous facets, which can be broken down as follows:

- Energy and environment
- Social development
- Economic development
- Disaster risk reduction

We have included some discussion of the last three points, but the focus is on energy and environmental aspects. Energy and environment are inter-twined because environmental concerns, objectives and mitigation can have a direct impact on the energy industries.

16.2 POLICY FRAMEWORK

GORTT's core objective is sustainable development for the benefit of all its citizens. The policy framework for sustainable development is set out in several documents, addressing different aspects of the issue, including:

- Medium Term Policy Framework, 2011-14
- National Spatial Development Strategy (NSDS) 2014
- National Climate Change Policy 2011
- National Environment Policy 2006
- Energy Policy 2014 Draft

GORTT's policies for sustainable development are set out in the *Core Strategy and Guidance for Regional Development*[1]. 24 core development policies support GORTT's objectives and vision (Figure 16-1).

[1] National Spatial Development Strategy, 2014

Figure 16-1 Core Development Policies

National Spatial Development Strategy – Core Strategy & Regional Guidance, 2014

Figure 7: NSDS Vision, Objectives and Policies

Institutions

Implementation of the policy framework is supported by various GORTT bodies and regional agencies, including:

- T&T:
  - Ministry of Planning and Sustainable Development (MPSD, www.planning.gov.tt) – the MPSD is tasked with coordinating and monitoring implementation of the National Framework for Sustainable Development, the latter task being carried out by the National Transformation Unit (NTU).
  - Monitoring and Evaluation Steering Committee – The Committee monitors implementation of Vision 2020 and comprises members from: Ministry of Planning Housing and the Environment, Ministry of Social Development, Office of the Prime Minister, Ministry of Finance, Tobago House of Assembly. Unclear whether this committee is still active.

- Ministry of the Environment and Water Resources (MEWR, no website) – responsible for protection of the environment
- Office of Disaster Preparedness and Management (ODPM, www.odpm.gov.tt) – ODPM falls under the authority of the Ministry of National Security. Its role is to build national Disaster Risk Management and Climate Change Adaptation capabilities and to coordinate response and recovery operations in order to protect the people, environment and economy and ensure a disaster resilient nation.
- Ministry of Finance & Economy (MOFE, www.finance.gov.tt) – responsible for administering the Public Sector Investment Programme (http://finance.gov.tt/three-year-public-sector-investment-programme-2015/) and Social Sector Investment Programme (http://finance.gov.tt/social-sector-investment-programme-2015/)
- Ministry of Community Development (MCD, www.community.gov.tt) – The MCD manages the Community Development Fund (CDF), which is its flagship programme for alleviating poverty in communities.
- Ministry of Energy & Energy Affairs (MEEA, www.energy.gov.tt/) – primarily concerned with the oil and gas sector. However, new focus areas have been added: renewable energy, energy efficiency, alternative energy.
- Renewable Energy Committee – 2011 report "*Framework for development of a renewable energy policy for Trinidad and Tobago*". Appointed by the Cabinet in 2008; unclear whether this committee is still active.
- Carbon Reduction Strategy Task Force – created in 2010 to develop a national carbon reduction strategy and proposals for the policy and regulatory environment for carbon capture, storage and trading and for a pilot Carbon Capture and Storage (CCS) project.
- Ministry of Public Utilities (MPU, www.mpu.gov.tt) – the Regulated Industries Commission under the MPU is an independent statutory body. It is responsible, inter alia, for establishing the principles upon which tariffs will be based, which is an important factor in aligning decision-making throughout the energy sector with government objectives. The Department of Economic and Social Affairs is also the focal point for the UN's Division for Sustainable Development.

▪ Regional organisations

- Caribbean Climate Innovation Center (CCIC, www.caribbeancic.org) – The Caribbean CIC is one of eight CIC's being established across the world and is jointly managed by the Scientific Research Council (SRC, www.src.gov.jm) based in Kingston, Jamaica and the Caribbean Industrial Research Institute (CARIRI, www.cariri.com) based in Trinidad and Tobago. The objective of the Caribbean Climate Innovation Center (CCIC) is to establish regional institutional capacity that will support Caribbean entrepreneurs and new ventures involved in developing locally-appropriate solutions to climate change mitigation and adaptation.
- Caribbean Community Climate Change Centre (CCCCC, www.caribbeanclimate.bz) – The CCCCC provides climate change-related policy advice and guidelines to the Caribbean Community (CARICOM) Member States and is the archive and clearing house for regional climate change data and documentation.
- Economic Commission for Latin America and the Caribbean (ECLAC) – ECLAC's objectives are to contribute to the economic and social development of Latin America, coordinating actions directed towards this end, and reinforcing economic ties among

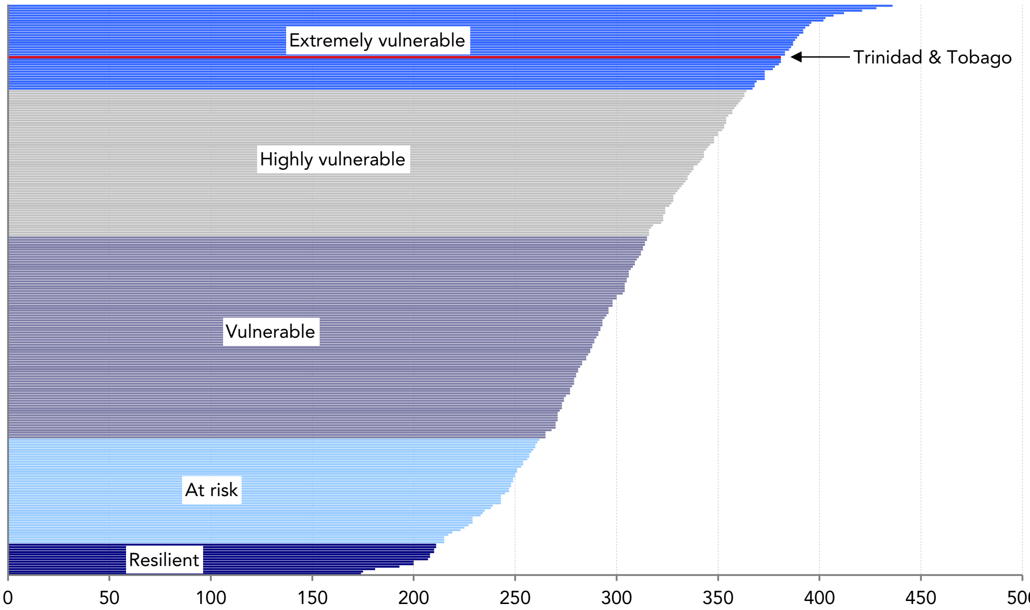
countries and with other nations of the world. ECLAC is headquartered in Santiago, Chile and is one of the five regional commissions of the United Nations. ECLAC sub-regional headquarters for the Caribbean were established in Port-of-Spain, Trinidad and Tobago, in 1966.

16.3 ENERGY AND THE ENVIRONMENT

GORTT's main concern in relation to energy and the environment is the effect of climate change. In common with many other countries, Trinidad & Tobago has over recent years observed an increasing frequency of severe weather patterns. A standardised Environmental Vulnerability Index (EVI) ranks T&T 22= of the 35 nations identified across the world as "extremely vulnerable" (see Figure 16-2).

Figure 16-2 Environmental Vulnerability Index

Methodology developed for Pacific Small Island Developing States



An important aspect of GORTT policy with respect to climate change is the reduction of greenhouse gas emissions, in particular of CO_2. Section 9.2 of the National Climate Change Policy 2011 obliges GORTT to:

1) Increase the use of renewable energy
2) Increase energy efficiency in commercial and residential buildings
3) Increase the use of alternative fuels and fuel switching in the transportation sector
4) Increase the use of cleaner technology in all GHG-emitting sectors
5) Enhance natural carbon sinks
6) Maximise the use of the carbon market
7) Enhance research and development

A Carbon Reduction Strategy Task Force was created in 2010 with a mandate to develop proposals for a regulatory, policy and institutional framework for carbon sale, storage, credit and trading and for a Carbon Capture and Storage (CCS) project.

Reporting GHG emissions is not institutionalised in T&T and, as such, it is difficult to access relevant information and results in data being incomplete[2]. Table 16-1 shows CO_2 emissions by sector as submitted by GORTT to the UNFCCC in 2013.

Table 16-1 CO_2 Emissions in T&T by sector

Second National Communication of the Republic of Trinidad and Tobago under the United Nations Framework Convention on Climate Change, April 2013, MEWR/EMA

Sector	Year	CO_2 emissions, kt
Energy sector	2006	63,455
Road transport	2005	3,617
Power generation	2006	2,488
Industrial*	2008	10,785
* includes cement, ammonia, iron & steel		

GHG emissions can be reduced by physical mechanisms such as increasing the use of renewable energy, improving energy efficiency or reducing consumption, but needs to be driven by a combination of market mechanisms and government direction.

16.3.1 Energy Efficiency

The objective of improving energy efficiency is an important part of government policy and has been consistently included in relevant policies, including the Environmental Policy (2006), the National Climate Change Policy (2011) and the Energy Policy (2014 Draft).

A study by the IDB on policy options for reducing greenhouse gas emissions[3] identified five measures in the energy sector with the cumulative potential to reduce GHG emissions by almost 53 MMt/y of CO_2e by the year 2030:

- Implementation of energy audits in LNG and methanol plants;
- Improvement in the use of heat;
- Revamping of ammonia plants;
- Reduction of venting and flaring emissions; and
- Improved power generation technology.

[2] See for example the section on Data Gaps in Chapter 2 of the *Second National Communication of the Republic of Trinidad and Tobago under the United Nations Framework Convention on Climate Change*, April 2013, MEWR/EMA or Section 3.1.3 of a recent report by the IDB "*Policy options for reducing greenhouse gas emissions in the oil, gas and petrochemical industry of Trinidad & Tobago*", IDB 2015

[3] *Policy options for reducing greenhouse gas emissions in the oil, gas and petrochemical industry of Trinidad & Tobago*, IDB 2015

GORTT is promoting the use of energy audits to identify cost-effective ways of reducing energy use and, for example, instructed National Energy in 2011 to carry out a study "to establish a framework for the execution of energy audits and the determination of baseline data for the petrochemical plants at the Point Lisas Industrial Estate"[4]. An energy efficiency study commissioned by GORTT in 2011 revealed the potential for a 15 percent reduction in energy use among the downstream plants located at Point Lisas.

Another area where more efficient use of gas may be achieved is in power generation. GORTT policy is now that future thermal power generation should be high-efficiency gas-fired combined cycle power plants (although high-efficiency gas engines are available[5] – like the units installed at Cove Estate, Tobago – that could be more suitable for the expected duty in T&T).

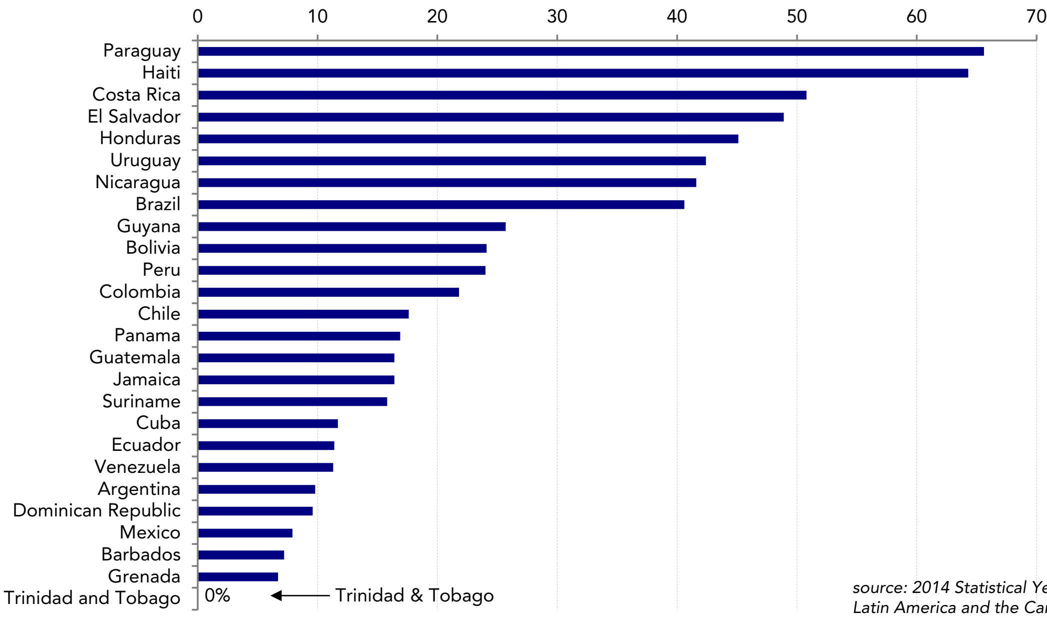
Existing plants could be closed and replaced with more efficient units. The average efficiency of the Powergen plants at Port of Spain, Point Lisas and Penal has been reported as only 24 %. The combined cycle power plant at La Brea completed in 2012 has a reported efficiency of 51 %, showing that higher efficiency is achievable. 24 % is very low; modern gas turbines and engines can achieve efficiencies over 40%[6] even in simple cycle. 1,186 MW (installed capacity) of Powergen's units are 30 or more years old and would be expected to be reaching the end of their operational lives. However, without data on individual plant operation and performance, it is not possible to opine on the possible economics of replacing the existing open cycle gas turbine plants with more efficient units.

16.3.2 Renewable Energy

There is presently no grid-connected electricity generation from renewable energy sources in T&T (see Figure 16-3).

Figure 16-3 Proportion of Electricity Generation from Renewable Energy Sources

Latin American & Caribbean countries, 2011



source: 2014 Statistical Yearbook for Latin America and the Caribbean, ECLAC

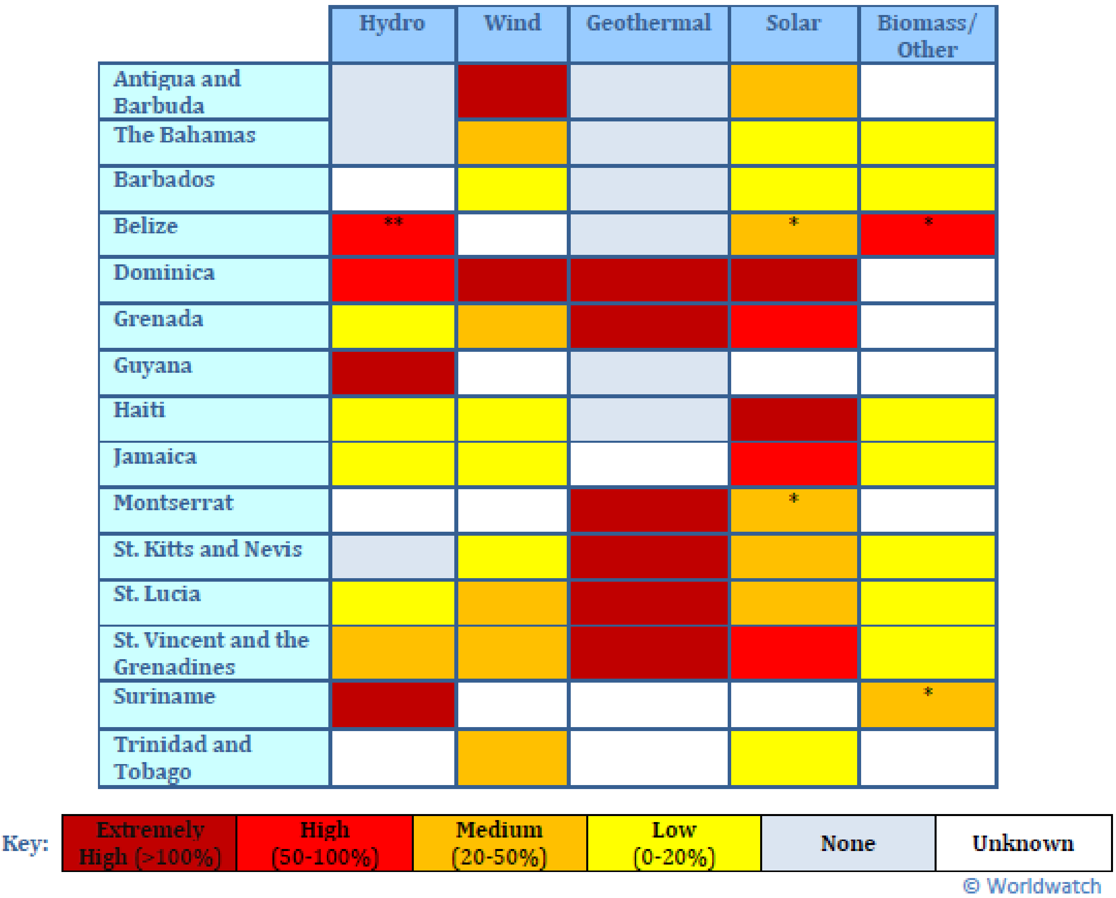
[4] *Carbon Reduction Strategies 2011-15 – Energy Policy Consultations*, MEEA
[5] Some gas engines can achieve a thermal efficiency of over 50 %.
[6] Under ISO conditions

Initial targets for renewable energy contribution to electricity generation were established as part of the broader Caribbean Sustainable Energy Roadmap and Strategy (C-SERMS) which is being developed to provide an implementation framework for the sustainable energy dimension of the CARICOM Energy Policy. The Caribbean Community (CARICOM) Secretariat adopted a trans-national target on behalf of its 15 member states, calling for a regional renewable electricity share of 20% by 2017, 28% by 2022, and 47% by 2027.

GORTT has so far announced a target of 5% of peak demand (or 60 MW) from renewable energy sources by 2020, which is modest compared with the potential. The 2013 Caribbean Sustainable Energy Roadmap describes the potential for electricity generation from wind in T&T as "medium", i.e. 20-50% of peak demand, which is currently around 1,500-1,600 MW. Perhaps surprisingly, the potential for electricity from solar is regarded as "low", i.e. less than 20% (Figure 16-4). Adding the two together gives potential solar and wind capacity of perhaps 600 MW.

Figure 16-4 Renewable Resource Potential as Share of Current Peak Demand

Caribbean Sustainable Energy Roadmap (C-SERMS), Phase 1_Summary 2013



A Wind Resource Assessment Programme was approved in 2011[7], and implementation is believed to have begun in late 2014. It is a 20-month programme, and results would therefore not be expected until

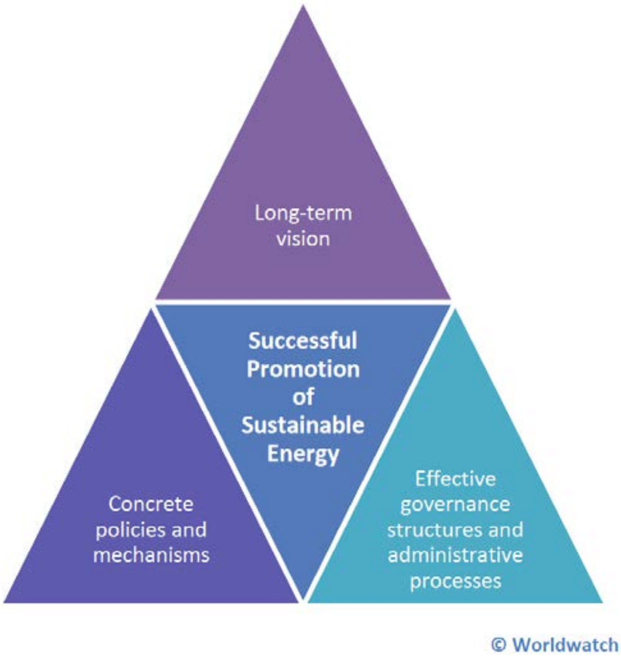
[7] http://www.energy.gov.tt/our-business/alternative-energy/wind-resource-assessment-programme-wrap/

2016. One of the key outputs will be the identification of 5 candidate sites for wind farm development, probably located on the east coast of Trinidad.

The C-SERMS report also identified institutional requirements for successful sustainable energy promotion (Figure 16-5). At present, the long term vision for renewable energy in T&T, and the policies, mechanisms, governance and administrative processes required for its successful implementation are largely absent. This may change with the planned introduction of feed-in tariffs (see p.16-8).

Figure 16-5 Components of Successful Sustainable Energy Promotion

Caribbean Sustainable Energy Roadmap (C-SERMS), Phase 1_Summary 2013



Feed-in Tariffs for Promotion of Energy from Renewable Sources

GORTT has stated that it intends to implement a feed-in tariff (FIT) policy by the end of 2014 and to introduce feed-in tariffs "shortly thereafter[8]". The 2010 Finance Act[9] introduced tax incentives for solar, wind and energy efficiency projects, but these have proved insufficient to result in significant renewable energy development.

GORTT has since been working with the United Nations Environment Programme (UNEP) to develop FITs and associated legislation for their introduction. The Prime Minister announced that a FITs policy would be in place by early 2015 and the implementation of this policy shortly thereafter[10].

FITs are frequently used to encourage the development of renewable energy sources by many different players, from large multi-nationals down to individuals. They are not the most economically-efficient, but have important advantages of attracting investment from the widest range of sources and maximising overall investment (provided, of course, that the incentive is generous enough to permit this).

[8] Prime Minister's address at the United Nations Climate Change Summit, New York, 23 September, 2014
[9] Finance Act No. 13 of 2010
[10] Prime Minister's address at the United Nations Climate Change Summit in New York, September, 2014

A United Nations Environment Programme (UNEP) report in 2012 identified the following FIT policy considerations and constraints[11]:

- Investor security
- Energy access
- Grid stability
- Policy cost
- Electricity price stabilization
- Electricity portfolio diversity
- Administrative complexity
- Economic development and job creation

Important considerations for GORTT would be the cost on one hand, and the potential for economic development and job creation on the other. The latter is consistent with its aims to diversify the economy away from reliance on oil and gas. How the additional cost of the FITs for renewable energy will be met has not been stated.

Green Fund

The Green Fund is the National Environmental Fund of T&T. This grant facility is available to community groups and organisations engaged in activities focusing on remediation, reforestation or conservation of the environment. The Green Fund is funded by a levy of 0.1 % on the gross sales of companies operating in T&T and administered by the Green Fund Executing Unit within the Ministry of Energy & Water Resources.

Very little of the Green Fund has been utilised (by the end of September 2013, TT$ 61.5m, or 1.9 %, had been spent, leaving a balance of $3.2bn) and it is not available to profit-oriented companies. Reform of the Fund's objectives to make it accessible for renewable energy and energy efficiency projects is recommended and would be consistent with government policy.

16.3.2.2 Greenhouse Gas Emissions

Greenhouse gas (GHG) emissions reductions can be promoted by governments by pre-investment, as in the case of CNG for transport, or by mandated performance standards, or driven by market mechanisms, whether on the price of fuel or the cost of emissions.

Venting and flaring

According to data from the CDIAC, flaring appears to have stopped in 1997[12]. However, there is anecdotal evidence that venting and flaring of gas still occurs from both onshore and offshore wells. Indeed, Petrotrin's proposed CDM project is specifically targeted to eliminate venting and flaring of associated gas from onshore and offshore oil fields. Venting is of concern with respect to climate change

[11] *Feed-In Tariffs as policy instrument for promoting renewable energy (RE) in developing countries*, Copyright @ United Nations Environment Programme, 2012

[12] T.A. Boden, G. Marland and R.J. Andres. 2015. Global , Regional and National Fossil-Fuel CO2 Emissions. DOI 10.3334/CDIAC/00001_V2010. Carbon emissions from flaring reported up to 1997, zero thereafter.

since methane has a global warming potential 21 times that of CO_2[13]. Data are not publicly-available to enable analysis and comment on the current situation.

Compressed Natural Gas

GORTT is targeting the use of CNG for transport as a cost-effective way of reducing CO_2 emissions from the transport sector and has mandated NGC to accelerate and expand the use of CNG as a major, alternative, transportation fuel in the country. The use of CNG has been mandated by governments elsewhere generally to reduce atmospheric pollution from burning gasoline or diesel (often in badly-maintained, polluting vehicles). In the case of T&T the aim is two-fold: (i) to reduce the cost of the subsidy on liquid fuels and also (ii) to reduce CO_2 emissions from the transport sector.

NGC CNG plans to invest over TT$2 billion on a phased basis over five years. The first phase, lasting two years, is projected to cost TT$500 million and will involve the construction of 22 new or revamped CNG-only fuel stations and conversion of over 17,000 vehicles. The second phase, lasting three years, is projected to cost TT$1.57 billion for the construction of more stations and conversions.

Carbon Capture and Storage

Carbon capture and storage has been proposed for T&T, including the use of CO_2 for enhanced oil recovery. The first step would the use of up to ~9 MMt/y of CO_2 available as a by-product from ammonia production[14].

16.3.3 Market Mechanisms

A study published by the IDB in March 2015[15] investigated a range of policy options to mitigate GHG emissions – sectoral crediting mechanisms, a cap and trade system, a carbon tax, regulatory instruments and voluntary agreements. It concluded that a carbon tax or individual crediting system based on CO_2 intensity compared with an industry benchmark would be the optimal choices. **It also concluded that a mandatory GHG reporting system should be implemented as a necessary first step** to enable the selected market mechanism to be implemented.

Emissions' trading – based on a cap-and-trade system – is another way in which countries can mitigate their emissions and can be effective in particular because it allows businesses to reduce global emissions at the least cost. The International Emissions Trading Association (www.ieta.org) has useful information on the design of carbon markets and case studies for schemes across the world. T he Carbon Reduction Strategy Task Force is tasked, among other things (see p.16-2), with developing proposals for carbon trading.

16.3.4 Social Development

As a "high income" country[16], T&T has made significant strides to achieving the Millennium Development Goals (MDGs). A civil society review of progress towards the Millennium Development Goals in T&T carried out by the Commonwealth Foundation in 2013 reported GORTT's assessment that

[13] Source: UNFCCC,
[14] "Of the 10 Mtpa of relatively pure CO_2 produced in 2010 by the ammonia sector, 8.7 Mtpa was available for CO_2 Enhanced Oil Recovery (EOR) but none was utilized for this purpose". *Trinidad & Tobago Credit System Concept Paper*, The Energy Chamber of Trinidad & Tobago, June 2014.
[15] *Policy options for reducing greenhouse gas emissions in the oil, gas and petrochemical industry of Trinidad & Tobago*, IDB 2015
[16] World Bank definition; Trinidad & Tobago was reclassified as a high income country in 2006.

all bar one of the MDGs either had been achieved or were likely to be achieved. This view is not shared by all the civil society organisations consulted. Unlike other countries, T&T appears not to have filed any MDG progress reports, which are available via the UNDP website[17].

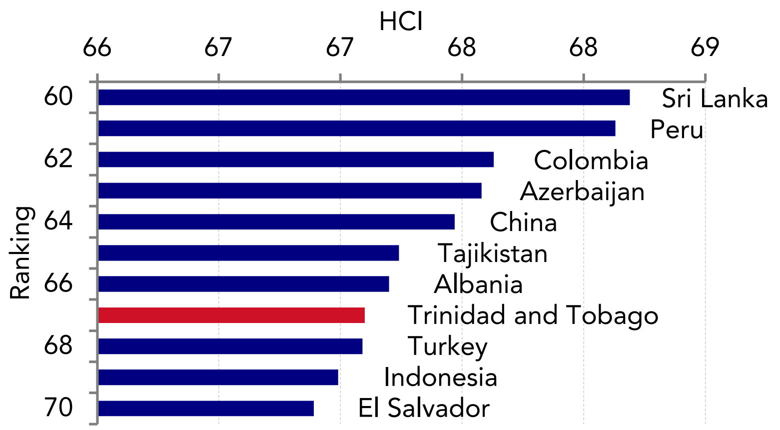
GORTT has established a Social Sector Investment Programme 2015, administered by MOFE, which focuses on projects to support the social aspects of the Medium Term Policy Framework (MTPF) in the areas of:

- Crime and Law and Order;
- Agriculture & Food Security;
- Health Care Services and Hospitals;
- Economic Growth, Job Creation, Competitiveness & Innovation; and
- Poverty Reduction and Human Capital Development.

The MTPF in turn reflects many of the MDGs. With a Human Capital Index (HCI) assessed by the World Economic Forum of 67.1, T&T ranks in the middle of the 124 countries, ahead of Turkey and Indonesia, and below countries such as China and Tajikistan (see Figure 16-6). The Minister of the People and Social Development was reported in 2011 saying that 27.3 percent of the population live below the poverty level.

Figure 16-6 Human Capital Index

Human Capital Report 2015, World Economic Forum[18]



[17] *MDG Progress Reports - Latin America and the Caribbean*: http://www.undp.org/content/undp/en/home/librarypage/mdg/mdg-reports/lac-collection.html

[18] http://reports.weforum.org/human-capital-report-2015/ "A nation's human capital endowment - the skills and capacities that reside in people and that are put to productive use - can be a more important determinant of long term economic success than virtually any other resource. The Human Capital Report details the findings of a new Index which measures countries on their ability to develop and deploy healthy, educated and able workers through four distinct pillars: Education, Health & Wellness, Workforce & Employment and Enabling Environment."

Table 16-2 How the Caribbean ranked in the UN's 2014 Human Development Index Report

UN Human Development Report 2014

2014 Ranking	Country	Human Development	HDI 2013	HDI 2013 (change on 2012)	HDI Ranking (change on 2013)
44	Cuba	Very high	0.81	(=)	(+15)
51	Bahamas	High	0.79	(=)	(-2)
59	Barbados	High	0.78	(-1)	(-21)
61	Antigua & Barbuda	High	0.77	(-1)	(+6)
64	T&T	High	0.77	(=)	(+3)
73	St. Kitts & Nevis	High	0.75	(=)	(-1)
79	Grenada	High	0.74	(-1)	(-16)
84	Belize	High	0.73	(=)	(+12)
91	St. Vincent & the Grenadines	High	0.72	(=)	(+ 8)
93	Dominica	High	0.72	(-1)	(-21)
96	Jamaica	High	0.72	(-3)	(-11)
97	St. Lucia	High	0.71	(-4)	(-9)
102	Dominican Republic	High	0.70	(=)	(-6)
121	Guyana	Medium	0.64	(=)	(-3)
168	Haiti	Low	0.47	(=)	(-7)

With a Human Development Index[19] (HDI) of 0.766, T&T ranks among countries with "high human development". Table 16-2 compares T&T with other Caribbean countries. T&T ranks in the top third, up three places on the previous year. However, as the change in HDI compared with 2013 shows, the headline change in ranking does not reflect actual performance in improving the quality of life for a population, which the HDI seeks to capture.

[19] "The Human Development Index (HDI) is a summary measure of average achievement in key dimensions of human development: a long and healthy life, being knowledgeable and have a decent standard of living. The HDI was created to emphasize that people and their capabilities should be the ultimate criteria for assessing the development of a country, not economic growth alone. The HDI can also be used to question national policy choices, asking how two countries with the same level of GNI per capita can end up with different human development outcomes. These contrasts can stimulate debate about government policy priorities." http://hdr.undp.org/en/content/human-development-index-hdi

16.4 ECONOMIC DEVELOPMENT

The Medium Term Policy Framework of 2011 and the 2014 National Spatial Development Strategy set out GORTT's objectives; a key objective is the diversification of the economy. The Public Sector Investment Programme 2015 is also administered by MOFE and focuses on programmes and projects investing in the economic and social infrastructure.

The Global Innovation Index (GII)[20] gives some clues as to where GORTT should focus to improve its achievements and aspirations to build a knowledge-based economy. The Index is broken down into innovation inputs and innovation outputs. GORTT can affect the former; the latter measure achievement. Overall, T&T ranks 90 out of 143 countries evaluated, with a score about half those of the top-scoring countries (Table 16-3).

Table 16-3 Global Innovation Index – Global Ranking

2014

Rank	Country	Score
1	Switzerland	64.8
2	United Kingdom	62.4
3	Sweden	62.3
4	Finland	60.7
5	Netherlands	60.6
6	United States of America	60.1
7	Singapore	59.2
87	Indonesia	31.8
88	Brunei Darussalam	31.7
89	Paraguay	31.6
90	T&T	31.6
91	Uganda	31.1
92	Botswana	30.9

The GII indicators are as objective as possible, i.e. calculated from data rather than subjective evaluation, but the constitution of the Index is itself subjective. Nevertheless, where a country is seen to perform better or worse than others allows policy-makers to investigate the circumstances relevant to the specific indicator or indicators. GII scores and ranking for T&T are shown in Table 16-4); ranking is out of 143 countries.

[20] The Global Innovation Index is co-published by Cornell University, INSEAD, and the World Intellectual Property Organization (WIPO, an agency of the United Nations, UN): https://www.globalinnovationindex.org.

Table 16-4 Global Innovation Index 2014 – T&T[21]

Scores are out of 100

	Category		Rank	Score	Distance to frontier*
1	Institutions	Innovation inputs	64	62.1	65%
2	Human Capital & Research		68	29.2	44%
3	Infrastructure		114	25.7	38%
4	Market sophistication		69	48.4	58%
5	Business sophistication		95	27.9	42%
6	Knowledge & technology outputs	Innovation outputs	102	21.9	36%
7	Creative outputs		95	27.1	41%
	Overall		90	31.6	49%

* Distance to frontier is the score for Trinidad & Tobago divided by the score of the best-performing country in each category, i.e. distance achieved, not distance to go.

T&T:

1) Scores fairly well for institutions, particularly the political environment, albeit less well for business and regulatory environments (ranking 51, 84 and 87 respectively).
2) Ranks in the top half of countries for human capital (68) despite a poor score for R&D (2.6, resulting in a ranking of 100 for this indicator).
3) Is let down in the score for infrastructure by the absence of a score for logistics performance and a low level of gross capital formation (expenditure on fixed assets of the economy, e.g. roads, railways, schools, etc., expressed as a % of GDP). The score is also reduced by a low ecological sustainability indicator arising from a low level of GDP per unit of energy, which is the inevitable result of an energy-driven economy (ecological sustainability rank 124, GDP per unit energy rank 123).
4) Could increase the market sophistication indicator by improving domestic credit to the private sector, where it ranks 98.
5) Low level of investment in R&D pulls down the score/ranking for business sophistication.
6) Low ranking in the innovation output indicators reflects the current situation, where T&T is in the early stages of moving to a knowledge-driven economy.

The indicators chosen to make up the GII suggest that GORTT could improve innovation by encouraging public and private sector investment in R&D and by investing in the "gross capital formation" (defined as outlays on additions to the fixed assets and net inventories of the economy, including land improvements (fences, ditches, drains); plant, machinery, and equipment purchases; and the construction of roads, railways, and the like, including schools, offices, hospitals, private residential dwellings, and commercial and industrial buildings). However, whilst the indicators can provide guidance on where policy

[21] Full scores may be found in "The Global Innovation Index 2014: The Human Factor in Innovation"

intervention might be beneficial, they need to be interpreted carefully. They also depend on the data being available, and so may not compare countries on the same basis[22].

16.4.1 Disaster Risk Reduction

The Office of Disaster Preparedness and Management (ODPM) was established in 2005 under the Ministry of National Security to take a proactive role in coordinating organisations and communities – ministries, agencies, etc. – to implement a comprehensive approach to disaster risk reduction (Comprehensive Disaster Management). The ODPM has a forward-looking policy that examines all aspects of disaster management: prevention, mitigation, preparedness, response, recovery and rehabilitation.

[22] For example, data on tertiary enrolment for T&T relate to 2004, whereas the data for other countries are much more recent.

16.5 CONCLUSIONS & RECOMMENDATIONS

Our conclusions and recommendations concerning energy and environment for sustainable development cover the following headings:

1) Policy implementation
2) Energy and carbon pricing
3) Data collection and publication
4) Renewable energy

Other studies have also included energy-related recommendations. For example, several the recommendations made by the IMF in its 2014 Article IV Consultation Report are energy-related[23]:

- The proceeds from extracting non-renewable resources should be saved and invested as a stepping stone to lasting prosperity.
    - This function is fulfilled by the Heritage & Stabilisation Fund.
- Fuel subsidies need to be curtailed and social programs rationalised.
- GORTT operations are increasingly hamstrung by a poorly functioning civil service.
- Growing statistical shortcomings have rendered the conduct of surveillance ever harder, and must be addressed.

The "*Framework for the Development of an Energy Policy for Trinidad & Tobago*", January 2011, recognises the main barriers to the successful implementation of renewable energy projects as including:

- Subsidised energy prices (petroleum products, natural gas, electricity).
- Lack of an appropriate legal framework.
- Limited fiscal incentives.
- Lack of education and awareness.
- Lack of publicly-available data.

The same barriers exist for energy efficiency.

16.5.1 Policy Implementation

GORTT has developed a comprehensive array of policies that include many good ideas. Implementation, however, appears to be more problematic, as translation into concrete actions can be delayed. A few examples:

- The Local Content and Participation Policy (2004) anticipated the establishment of a secretariat in the Ministry of Energy that would support a permanent local content committee. This secretariat has not been established.
- The 1998 draft Disaster Preparedness and Response Bill has to date not been finalised. The update is required to align with current thinking on best practice in comprehensive disaster management and its implementation in T&T.

[23] Extracted from the summary of key issues: Trinidad and Tobago: 2014 Article IV Consultation-Staff Report, published September 03, 2014; ISBN/ISSN: 9781498358804/1934-7685.

- A Wind Resource Assessment Programme was announced as long ago as 2011 and was included in the 2012 Budget[24], but has not been completed.

Without wide consultation and analysis it is difficult to judge the causes for such delays – whether changes in policy, political "realities" or staffing or funding issues – and as such it is not possible to make specific recommendations. In general terms, someone (could be an organisation) should be held accountable for achieving agreed objectives (SMART – i,e., Specific, Measurable, Achievable, Relevant and Time-bound) and be given the authority and resources to do that.

16.5.1.1 Energy and Carbon

Energy Efficiency

Energy efficiency should be promoted in the first instance by eliminating the subsidies currently paid for electricity and petroleum products (see below).

T&TEC should undertake a Least Cost Generation Expansion Plan, incorporating realistic costs for gas and CO_2, to determine whether the replacement of the existing Powergen plants with more efficient generating units – including modern designs of open cycle gas turbines, combined cycle gas turbines and reciprocating "diesel" engines – would be cost-effective.

Energy Pricing

The inefficiencies of energy subsidies as a means of wealth redistribution are well known. Not only do they mainly benefit the rich, they encourage wasteful consumption (and consequently also raise the subsidy burden). Energy subsidies also distort decision-making by damaging incentives for supply side and demand side efficiency improvements[25] and creating an uncompetitive economic environment for alternative sources of energy such as renewables or CNG.

Organisations within and outside of T&T such as the Energy Chamber and IMF have been calling for a removal of energy subsidies for many years, and subsidy reform is accepted best practice worldwide. The IEA records energy subsidies in T&T as costing $803/person in 2013, equivalent to 3.9% of GDP (Table 16-5), although it is not clear whether it captures the full range of subsidy components. Subsidy reform would result in cost-reflective energy pricing, and would include an adequate return on investment as well as recovery of fuel, O&M, capital, taxes, duties and levies and other costs.

Table 16-5 Energy subsidy in T&T, 2013

IEA online subsidy database, real $2013

Average subsidization rate	35.9%
Subsidy	$803/person
Subsidy as share of GDP	3.9% of GDP
Electricity	$0.5bn
Oil (petroleum)	$0.6bn

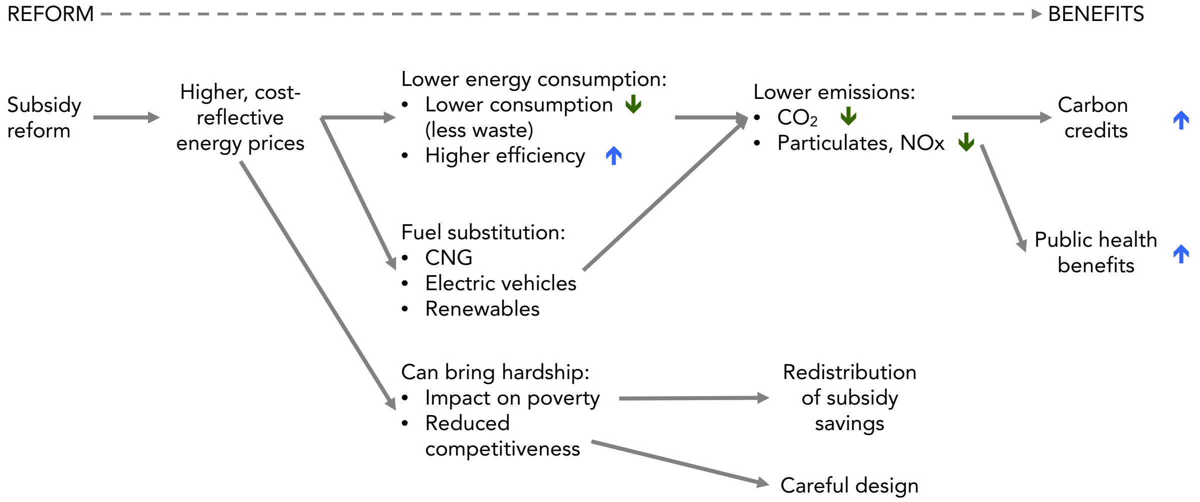
[24] National Budget Statement 2012 "Government will commission a national energy efficiency study and pilot project and a national wind resource assessment programme".

[25] The MEEA noted in 2011 that "current pricing of electricity is low for residential and commercial customers and this has led to inefficiency in the use of electricity".

Subsidy reform would align with GORTT's stated energy efficiency, carbon reduction and climate change policies (Figure 16-7) and is necessary for the achievement of its objectives in these areas.

Figure 16-7 Subsidy Reform Brings Benefits

but also requires careful design to mitigate possible hardships



However sensible the policy, removing energy subsidies is likely to be unpopular as it will increase costs both directly (higher energy costs) and indirectly (e.g., higher transport, food costs). Subsidy reform should therefore be introduced over time, and alternative means found and implemented to transfer some or all of the savings to social benefits such as through the welfare system or health, education and training, etc. programmes.

Higher fuel prices would be expected to lead to a reduction in demand and, over time, use of more efficient vehicles and possible fuel substitution to CNG or electric vehicles. Higher fuel costs would encourage efficient operation and maintenance, which should also lead to public health benefits from lower levels of atmospheric pollution.

Lower consumption would result in lower CO_2 emissions, which is also a GORTT objective.

Carbon Trading

The first step to any mechanism for reducing GHG emissions will be to measure, monitor and report emissions. At present there appears to be no formal measuring and reporting requirement. A mandatory reporting system should be the first step to controlling GHG emissions.

The Energy Chamber has called for Caribbean governments to establish a regional emissions trading scheme to help the islands attract investment in clean energy projects from rich nations looking to outsource their carbon cuts under a new UN pact.

Current proposals for carbon trading appear to envisage that firms in T&T would undertake emissions reduction projects in return for credits that would have some value on the international marketplace. However, the Clean Development Mechanism has been operational since 2005, and the only project proposed so far in T&T (to eliminate venting and flaring of associated gas from Petrotrin onshore and offshore oil fields[26]) has not yet been implemented (whereas, to date 7641 CDM projects elsewhere have registered CO_2 reductions with the UNFCCC). There are also uncertainties over future carbon prices and the ability to widely trade the Certified Emissions Reductions (CERs) generated under the CDM that challenge the implementation of future CDM projects.

Elsewhere, in an effort to provide more certainty and a stronger incentive to reduce emissions, the UK government introduced a carbon floor price in 2013. The policy was implemented as a result of the perceived failure of the European Emissions Trading System (ETS) to incentivise emissions reduction projects (which included generating funds for several planned European CCS projects). Emitters pay the difference between the forward price on the ETS and the carbon floor price. The carbon floor price is set on an upward trend, from £18/t in 2015 to £30/t by 2020 and £30/t by 2030.

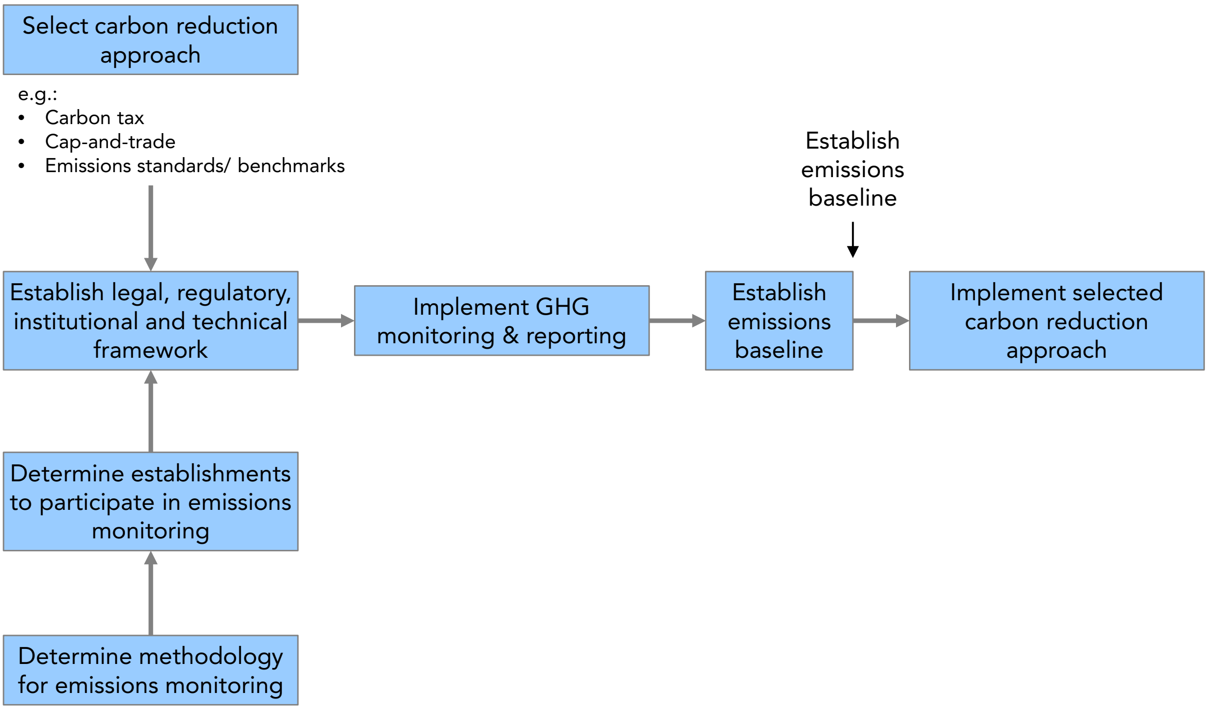
A trading mechanism should result in the optimum economic portfolio of projects, but implementation is complex and the cost-benefit of implementing a new platform for (T&T or) the Caribbean as a whole must be weighed against the cost-benefit of simpler programmes, such as a carbon tax, intensity-based performance standards for each industry (e.g., as in New Zealand) or joining an existing platform (it should be noted that this last has not yet happened anywhere, although it should be feasible – the concept of a global carbon trading platform has been discussed, and could emerge from the UN climate talks to be held in Paris in December 2015).

Setting the level of a carbon tax would be difficult at the moment. To avoid making export industries uncompetitive a carbon tax could initially be applied to domestic businesses. Later, when the international framework for climate change mitigation becomes clearer and a global carbon price can be established, export industries could be brought under the carbon tax. However, a carbon tax would push up energy prices, which would involve the same considerations as removal of energy subsidies (p.16-17).

The process for implementing GHG emissions monitoring and introducing an emissions trading scheme or alternative mechanism to incentivise emissions reductions is outlined in Figure 16-8.

[26] Petrotrin Oil Fields Associated Gas Recovery and Utilization Programme of Activities

Figure 16-8 Roadmap for Development of GHG Monitoring and Trading



16.5.2 Data

There appears to be a widespread lack of data on the energy sector, achievement of MDGs, GHG emissions, gas flaring and venting. For example, the only data recorded by UNFCCC for T&T relate to the base year of 1990, and a 2015 presentation by MEEA on renewable energy policies presented emissions data by sector for 2008.

Comprehensive data on GHG emissions is a fundamental prerequisite for establishing a Caribbean emissions trading market. It is recommended that reporting of energy sector and GHG emissions data be mandatory. All major energy users should be required to provide data to MEEA and MEWR on energy inputs (natural gas, LPG, petroleum and electricity), outputs (products, volumes and composition) and GHG emissions by constituent (CO_2, methane, nitrous oxide, fluorinated hydrocarbons and by process (e.g. combustion, flaring, venting). Issues of commercial confidentiality can be addressed by publishing data in aggregated form, by sector or industry.

The lack of published data on power sector, energy use and GHG emissions gives the impression that energy efficiency and climate change mitigation are in practice low priority. It appears not to be (just) an issue of publication. The 2013 *Second National Communication of the Republic of Trinidad and Tobago Under the United Nations Framework Convention on Climate Change* illustrates the shortage of up to date data, reporting CO_2 emissions only to 2005-6 (in some cases to 2008). The report noted that “One of the biggest challenges faced by the compilers of the inventory, both the initial and the second, was the difficulty in accessing relevant information”.

16.5.3 Renewable Energy

The renewable energy target for 2020 – only 5 % of current peak demand, or 60 MW – is modest in size, but is to be achieved from a standing start. Successful implementation of the necessary legal, regulatory, technical and commercial framework will be required to achieve even this modest target.

Key issues to be resolved include:

- Open access – rights to use the grid, subject to appropriate standards (Grid Code) and charges.
- Grid interconnection – cost, technical standards (Grid Code).
- Priority dispatch for renewable energy sources.
- FITs – level, quantity, PPAs and counterparties.
- Net metering and net billing – basis for paying the FIT.

The commercial framework will include the FITs for each technology, the quantity to be purchased and how (competitive tender), and the purchasing agency (probably T&TEC).

The Wind Resource Assessment Programme (WRAP) should be expedited to facilitate development of the wind resource along the east coast. The WRAP seeks to identify five candidate sites for development, which would act to establish the technology in T&T.

Reform of the Green Fund's objectives – currently restricted to community organisations for activities that relate to the remediation, reforestation or conservation of the environment – to make it accessible for renewable energy and energy efficiency projects, perhaps including for-profit companies, is recommended and would be consistent with GORTT policy.

Section 17 Institutional: Integration with Non-Energy Sector

17.1 OVERVIEW

Countries in which the dominant economic sector is based on the exploitation of natural resources face a number of economic challenges:

- Natural resources are finite and subject to depletion. They represent part of the capital stock of the nation and the benefits of their exploitation should be invested for the present and future benefit of the nation. The challenge is to achieve inter-generational equity. How best to spread resource depletion and the income yield from resource exhaustion between the present and future generations?
- Natural resource prices are inherently volatile. Managing such volatility is difficult, particularly so for countries that are dependent on natural resources as a major source of income and foreign exchange. Governments are predisposed to increase expenditure rapidly in line with revenue during a resource-driven boom. However, once in progress, such expenditure is difficult to reverse, resulting in heavy fiscal deficits and associated problems when resource prices collapse.
- Natural resource based industries (particularly oil and gas) are highly capital-intensive. While these industries are major sources of wealth creation, they do not provide sufficient employment opportunities to absorb a significant portion of the labour force. It therefore falls to the Government to use the rents derived from the sector to expand state funded employment and social security. This is often problematic and can result in a boom in current spending at the expense of savings.

17.2 NATURAL RESOURCE FUNDS

Natural resource or reserve funds are an instrument in the fiscal policy mix designed to meet the challenges outlined above. For governments of petroleum-dependent countries, reserve funds provide a link to the global capital markets: value can be stored and withdrawn either to mitigate short-term fluctuations in income or as part of the inevitable long-term replacement of oil in the ground by other assets. The existence and functioning of reserve funds is an essential part of the alignment between depletion policy, with all its uncertainties, and development policy, with its long-term, slow-changing aspirations and constraints.

There are two main types of natural resource funds, Stabilisation Funds and Savings/Heritage Funds:

- A Stabilisation Fund serves to build up a pool of resources which can be used to mitigate the impact of swings in a government‘s revenue, which often arise because of volatile natural resource prices. In years of high prices money is set aside and invested, to be withdrawn in years of low prices to make up planned revenue shortfall.
- A Savings/Heritage Fund is used to accumulate wealth for future generations through the investment of surpluses earned from the natural resource income. This type of fund directly addresses the inter-generational equity challenge and is governed by detailed guidelines for deposits to, investment of, and withdrawals from the fund.

Some examples of established funds are shown in Table 17-1.

Table 17-1 National Resource /Reserve Funds

(Source: IMF)

State	Name	Objective/ Date Established	Rules for Accumulation	Rules for Withdrawals	Management
Alberta (Canada)	Alberta Heritage and Saving Funds.	Savings/1976	30% of Resources until 1983, from 1984 –1987 15%	Discretionary transfers to the Budget	APFC, Members of Parliament and Provincial Treasurer
Alaska (USA)	Alaska Permanent Fund	Savings/1976	50% of certain mineral revenues (increase from 25% in 1980)	Principal Invested permanently. Use of earnings decided by Governor or Legislature.	Independent Trustee, Governor and Legislature
Chile	Copper Stabilization Fund	Stabilization/1985 activated in 1987	Based on Gov't set reference price	Determined by the reference price set.	Ministry of Finance and Central Bank
Kuwait RFFG	Reserve Fund for Future Generations	Savings/1976	10% of all Gov't Revenue	Discretionary transfers to the Budget with approval	Minister of Finance, Central Bank Governor and other officials
Kiribati	Revenue Equalization Reserve Fund	Stabilization & Savings/1954	25% of all phosphate revenue	Discretionary transfers to Budget with approval	Minister of Finance, Secretary of the Cabinet and other officials
Norway	State Petroleum Fund	Savings/1990 activated in 1995	Net Gov't Oil Revenue	Transfers to the Budget to finance non-oil deficit with approval	Ministry of Finance & Central Bank
Oman SGRF	State General Reserve Fund	Savings/1980	Since 1998, oil revenue in excess of budgeted	Discretionary transfers to the budget	Autonomous gov't agency
Oman Oil Fund	Oil Fund	Oil Sector Investment/1993	Since 1998 market value of 15000 barrels per day	Na	Ministry of Finance
Venezuela	Macro Resources Stabilization Fund	Stabilization/1998	Since 1999, 50% of all revenue above reference value	Transfers to budget based on the reference value set	Parliament and Executive

A further motivation for a fund is that in many cases the comparative advantage of the oil producer means that while in principle domestic spending to diversify the economy is sound, in practice it will take a long time for any serious development of the non-oil sector to occur, implying a very low rate of return on domestic investment. In such circumstances, transforming petroleum revenues into financial or real foreign assets via a special fund may well be the most appropriate option. This is the key driver for sovereign wealth funds such the Abu Dhabi Investment Authority or the Qatar Investment Authority.

Some funds are managed directly by the existing fiscal authorities and operate inside the budget framework without any earmarking of revenues. They are often termed virtual funds or informal funds. Formal funds are often managed by special appointed boards and operate (at least in theory) partly or wholly outside the government's budget. In addition, the revenues derived from formal funds are often earmarked for special purposes. In general, the working of any fund is very much a function of the institutional capacity of the country to manage it effectively.

Examples of successful natural resource funds include Norway's State Petroleum Fund, Chile's Copper Stabilization Fund, Botswana's Revenue Stabilization Fund and (to some extent) Kuwait's Oil Funds. In these countries the funds have assisted in accumulating assets to meet future needs when natural resources become depleted. In addition, they have contributed to enhancing the effectiveness of fiscal policy by de-linking budget expenditures from revenue availability, thus avoiding irresponsible levels of government spending during boom years. Finally, the funds (especially in Norway and Chile) have moderated real exchange rate appreciation and thus also weakened Dutch disease symptoms.

17.3 THE HERITAGE AND STABILISATION FUND

17.3.1 Overview

GORTT has developed a fund which is designed to cover both stabilisation and inter-generational wealth saving in a single entity. The Heritage and Stabilisation Fund (HSF) was established first as an Interim Stabilisation Fund in 2000 and formalised in 2007 as the HSF. The HSF has two stated primary purposes:

- It is designed to stabilise or cushion the economy in the event of a sustained shortfall of GORTT revenues as a result of a collapse of export prices of crude oil and natural gas (i.e. the stabilisation objective.)
- It is the medium through which the country saves oil and gas wealth for future generations.

The HSF is governed by rules of withdrawal and deposit. GORTT may withdraw from the Fund if actual petroleum revenues are less than GORTT projected them to be by 10% or more. However only a stipulated amount can be withdrawn in any given year, i.e. either 60% of the amount of the shortfall of petroleum revenues, or 25% of the funds credit balance, whichever is less. From the inception of the fund to the end of FY 2012 no withdrawals had been made.

GORTT is mandated to make deposits to the HSF under the following conditions:

- If the quarterly actual petroleum revenue exceeds the amount estimated by GORTT by more than 10% the amount equivalent to that excess (in US$) must be deposited in the HSF.
- If the actual quarterly revenue exceeds the estimated petroleum revenue for that quarter by less than 10%, the amount equivalent to the excess (in US$) may be deposited in the HSF from the Consolidated Fund (GORTT's bank account). The decision on whether any of the excess revenue should be deposited resides with MOFE.

The resources of the fund are to be derived from three sources:

- Monies transferred from the Interim Revenue Stabilisation Fund, which was established in 1999 and had accumulated the sum of US$1.3 billion at the end of fiscal year 2006.
- Petroleum revenues deposited into the fund,
- Assets acquired and earned from investments by the fund.

There are a number of rules as to governance of the HSF, which include:

- It is mandatory that the Board must include one member from the Central Bank and one member from the MOF.
- Three members would constitute a quorum and decisions would be made by majority vote.
- The Board shall determine the governance structure and operational and investment guidelines of the fund.
- The Board shall delegate its responsibility for the management of the fund to the Central Bank.

In terms of transparency and accountability, the rules provide for an annual audit by the Auditor General, as well as the submission of quarterly and annual financial statements to the Minister. The audited Annual Financial statements must be laid in Parliament within four months of the close of the financial year.

The fund ranks well in terms of governance against other natural resource funds. In a review by the Resource Governance Index in 2013, T&T ranked second to the Norwegian Government Pension Fund out of 23 funds.

17.3.2 HSF Fund Performance

The latest data available, given in Table 17-2, indicate that the fund had assets of over US$5 billon at the end of September 2013. In the period from September 2007 no withdrawals had been made from the fund. It was announced by the Finance Minister on February 15th 2015 that no deposits would be made into the fund for 2015 due to the oil price falling below the target price.

Table 17-2 HSF Valuation (USD)

(Source: HSF Annual Report 2013)

Valuation Date	Net Asset Value	Financial Year Income	Accumulated Surplus Gains/Losses	Contributions
Sept 30, 2007	1,766,200,701	42,217,837	41,966,361	321,706,043
Sept 30, 2008	2,888,421,556	67,894,134	110,379,131	1,054,174,457
Sept 30, 2009	2,964,686,478	35,807,757	186,755,766	-
Sept 30, 2010	3,621,984,041	88,381,935	364,361,226	477,344,263
Sept 30, 2011	4,084,016,158	179,748,798	374,074,067	451,400,519
Sept 30, 2012	4,712,376,278	125,221,977	125,221,977	794,770,772
Sept 30, 2013	5,154,027,747	312,776,304	1,193,778,722	42,519,782

There has been some concern that the decision to have a single fund with two purposes could create complexity in fund management and that the short-term requirements of stabilisation could disadvantage the long-term heritage goals. Other countries that started out with a commingled single fund have chosen to separate them into two separate funds. Russia created a separate National Wealth Fund to address the objective of intergenerational transfer. In 2006, Chile restructured its Copper Stabilization Fund, first established in 1985, into two separate funds; the Pension Reserve Fund and the Economic and Social Stabilization Fund.

Clearly to date the fund has acted much more a heritage fund, as there have been no withdrawals since its inception.

17.3.3 Fund Sufficiency

While the growth of the fund has been impressive the accumulated net asset value per capita as of 2013 was US$ 3,846 which would still leave much to be done in terms of establishing an inheritance. Work done by the IMF and IADB indicates that the petroleum wealth stock for the country should be between 86% and 136% of GDP whereas at present the HSF represents around 21% of GDP, although it should be acknowledged that it has only been developed since 2000. Certainly the revenue base could be increased by including upstream taxes not presently covered (e.g. unemployment levy, the oil impost and signature bonuses) and downstream tax revenues from LNG, petrochemicals, NGC dividends etc. Significant inflow would be required to reach these levels, and this kind of saving would mean a concerted fiscal adjustment.

Given the current value of the fund and current activity in the energy sector an argument could be made to de-emphasise the stabilisation aspect of the fund and focus more on savings. However, a smaller stabilisation fund would imply more fiscal adjustments or increased borrowing (which in turn raises other questions). This change of focus would imply tighter withdrawal rules (currently the fund allows up to 25 per cent of fund withdrawal a year to a minimum balance of US$1 billion in the fund). The recognition by GORTT that it may have to forgo current needs for future development will be especially challenging in an environment of lower oil prices and reduced petroleum production, and hence lower GORTT revenues.

17.4 INVESTMENT IN THE NON-ENERGY SECTOR

Funds are not the only way that governments can influence integration with the non-energy sector. Investment in infrastructure, education, R&D and in fostering new businesses and creating an environment – physical, human, regulatory, fiscal and legal – in which business can flourish are even more important. GORTT can also encourage existing industries to invest in local companies, such as spin-offs from their main businesses, as part of a corporate social responsibility programme and provide incentives such as tax-deductibility of investment or of salaries of employees seconded to a start-up business for up to, say, three years. A government can also encourage investment, whether local or from abroad, through trade promotion or otherwise. In T&T, this is done via embassies and the Investment Promotion Agency of Trinidad and Tobago (InvestTT).

New non-energy businesses can be integrated with the energy sector in one of two ways, either using products produced by existing industries as feedstock or by providing services. The scope for downstream industries is limited by the range of feedstocks available, primarily methanol, ammonia and urea.

The services sector, which in 2014 accounted for 81 billion TT$, or almost 52 % of total GDP, is by far the largest element in T&T's non-energy GDP. However, by comparison, service contractors working in the petroleum sector realised 2.7 bn TT$, equivalent to only 3 % of the non-energy service sector, which could surely be expanded. Breakdowns of 2013 GDP in the petroleum and non-petroleum sectors are shown in Figure 17-1 and Figure 17-2.

Figure 17-1 GDP Breakdown, Petroleum Sector (2013)
Million TT$, CSO

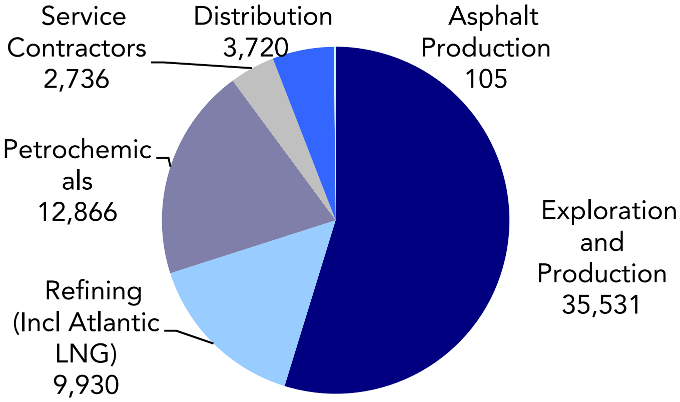
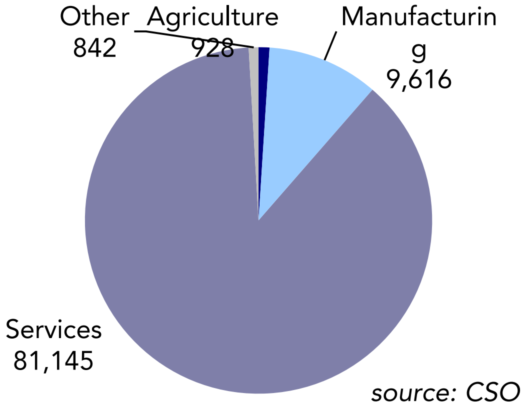


Figure 17-2 GDP Breakdown, Non-Petroleum Sector (2013)
Million TT$, CSO



17.4.1 Policy Framework

The policy framework for the development of the non-energy sector is set out by the Medium Term Policy Framework, 2011-14 (MTPF), published in October 2011, which targets lasting "prosperity for all". The document remains current. The ministry responsible for coordinating implementation of the MTPF is the Ministry of Planning & Sustainable Development.

GORTT's economic and social transformation strategy underpinning the MTPF seeks to achieve socio-economic development based on an increasingly knowledge-/innovation-based economy, taking into account the spatial and environmental constraints of development on a small island. The MTPF is based on seven pillars, as shown in Table 17-3.

Table 17-3 Seven Interconnected Pillars for Sustainable Development

Medium Term Policy Framework 2011-14

	Description	Explanation
Pillar 1	People-Centred Development	We need everyone and all can contribute
Pillar 2	Poverty Eradication and Social Justice	Preference for poor and disadvantaged
Pillar 3	National and Personal Security	Human security for peace and prosperity
Pillar 4	Information and Communication Technologies	Connecting T&T and building the new economy
Pillar 5	A More Diversified, Knowledge Intensive Economy	Building on the native genius of our people
Pillar 6	Good Governance	People participation
Pillar 7	Foreign Policy	Securing our place in the world

The MTPF was followed by the 2014 National Spatial Development Strategy (NSDS), which sets out GORTT's guidance for what, where and how development should proceed over the next 20 years to achieve its vision for T&T in 2033. The NSDS "provides the framework for decisions about the ways in which the national space will be used and developed over the next decade and beyond[1]."

Institutions

Development of the non-energy sector is in the hands of several ministries, advisory boards and agencies, such as:

- Ministry of Trade, Industry, Investment and Communications (MTIIC, www.tradeind.gov.tt/) – The MTIIC "leads the drive to achieve and sustain the growth of the economy through the development and expansion of the non-energy sector, by diversifying the economy and making local industries more competitive in the global economy." The Ministry's core responsibility is to grow trade, business and investment, particularly through driving the non-energy sectors of the economy.
  - Evolving Tecknologies and Enterprise Development Company Limited (e Teck, www.eteck.co.tt) – e Teck is a Special Purpose State Enterprise under the Ministry of Trade, Industry, Investment & Communications (MTIIC) that supports the economic diversification of T&T. e Teck's mandate focuses on developing and managing new Economic Zones, optimising existing industrial parks on a commercial basis and managing its hotel assets[2].
- Ministry of Planning and Sustainable Development (MPSD, www.planning.gov.tt/) – The MPSD is responsible for implementing the NSDS.

[1] National Spatial Development Strategy for Trinidad and Tobago – Core Strategy and Regional Guidance
[2] e Teck Corporate Profile. Incidentally, there is no real logic for e Teck's continuing ownership and management of hotel assets, which could be done perfectly well by the private sector. MTIIC/e Teck should consider divesting its hotel assets to focus on the development of industrial/business parks to support diversification of the economy.

- Economic Development Board (EDB, http://edb.planning.gov.tt/) – an Advisory body to the Minister of Planning and Sustainable Development responsible for sustainable diversification of the economy beyond the energy sector.
- Council for Competitiveness and Innovation (CCI, http://cci.planning.gov.tt/) – an Advisory Board to the Ministry of Planning and Sustainable Development, with responsibility to develop and implement a holistic and competitive innovation policy that will transform the economy by lowering its dependence on hydrocarbons as well as improving its global competitiveness rank over the next ten (10) years. Its remit may be summarized as improving Trinidad & Tobago's GCI ranking (see p.7-17-10) and building national awareness of innovation.
- EDB and CCI share a common Secretariat.

▪ Ministry of Energy & Energy Affairs (MEEA, www.energy.gov.tt) –MEEA is responsible for developing, monitoring and enforcing the Local Content Policy.

17.4.2 Investing in Infrastructure

High quality infrastructure is necessary to support the knowledge-based economy and attract the sorts of businesses that T&T wants.

This infrastructure includes adequate, good road capacity, ports, airports and public transport, high-speed telecommunications, reliable electricity supply, sufficient good quality housing. GORTT can also help kick-start businesses by building industrial parks and ensuring that investors can find affordable business accommodation. Much of the infrastructure listed is the responsibility of GORTT, and all relies on high quality forward planning by the various government departments and agencies.

17.4.3 Investing in People and Business

Education

Education at all levels from primary through to tertiary education is vitally important to ensure that T&T has an adequate supply of qualified people. GORTT could consider sponsoring industrial apprenticeships to provide a guaranteed route for young people to enter the employment market (although we note that unemployment is low, at 3.6 % of the total labour force in 2013, *World Bank Development Indicators*).

GORTT provides free tuition up to undergraduate level and in 2004 launched the Government Assistance for Tuition Expenses (GATE) programme, which provides financial assistance to citizens of T&T who are pursuing GATE-approved tertiary level programmes at local and regional public and private educational establishments. GATE funds cover 100% of tuition expenses for undergraduate students and up to 50% of tuition expenses, to a maximum of TT$10,000, for postgraduate students. GORTT is "repaid" by a requirement that funded students work in T&T for a certain minimum period of time depending on the level of funding received.

Business Environment

GORTT could do more to encourage investment by improving the business environment. Figure 17-3 and Figure 17-4 show areas – especially: dealing with construction permits[3], registering property and enforcing contracts – where improvement would help the ranking and hence T&T's attractiveness for

[3] The MPSD issued Request for Proposals for an automated construction permitting system in August 2014, which should speed up the process of applying for and receiving construction permits.

investors. However, T&T is among the ten economies that improved the most in 2013/2014 in the areas tracked for the "Doing Business" index, having improved its ranking from 91 to 79 out of 189 countries assessed over a range of quantitative indicators on business regulations and the protection of property rights[4].

Figure 17-3 Rank out of 189 Countries
Doing Business 2015: Going Beyond Efficiency[5]

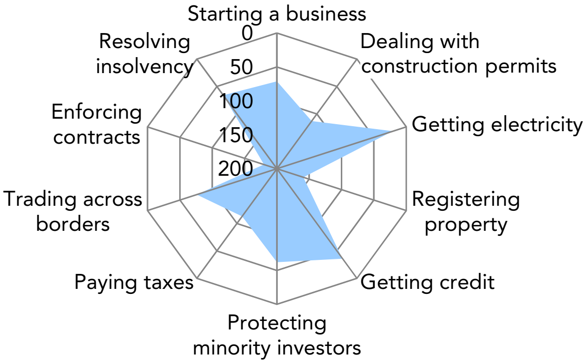
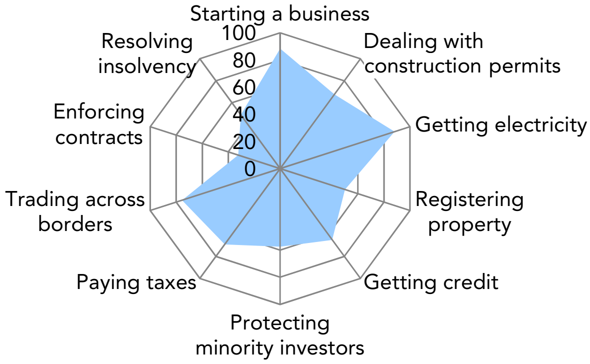


Figure 17-4 "Distance to Frontier"
Doing Business 2015: Going Beyond Efficiency



The distance to frontier score benchmarks economies with respect to regulatory practice, showing the absolute distance to the best performance in each Doing Business indicator. An economy's distance to frontier score is indicated on a scale from 0 to 100, where 0 represents the worst performance and 100 the frontier.

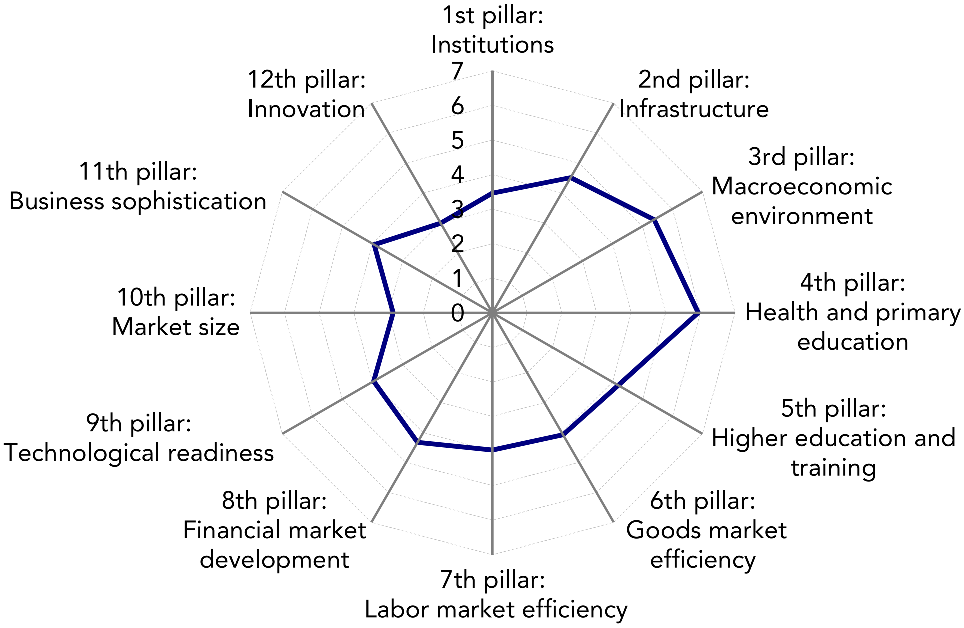
T&T's Global Competitiveness Index (GCI) ranking slipped from 36th out of 80 countries in 2003 to 92 out of 148 countries in 2013-2014, but then rose to 89 out of 144 countries in 2014-15[6]. The GCI is calculated from 118 parameters indicative of each country's performance under the sub-indices and "pillars of competitiveness" shown in Figure 17-5. T&T scores highly against the 3rd and 4th pillars (macroeconomic environment and health and primary education), but relatively poorly against the 1st, 10th and 12th pillars (institutions, market size and innovation).

Figure 17-5 The GCI Sub-Indices and the 12 Pillars of Competitiveness
Source: Annual Report on Performance 2013, MPSD

[4] World Bank. 2014. "*Doing Business 2015: Going Beyond Efficiency*". Washington, DC: World Bank Group. DOI: 10.1596/978-1-4648-0351-2. License: Creative Commons Attribution CC BY 3.0 IGO.
The most recent round of data collection for the study was completed in June 2014.
[5] Doing Business 2015 Trinidad and Tobago Economy Profile.
[6] Global Competitiveness Report 2014-15, World Economic Forum

Figure 17-6 Global Competitiveness Index – T&T

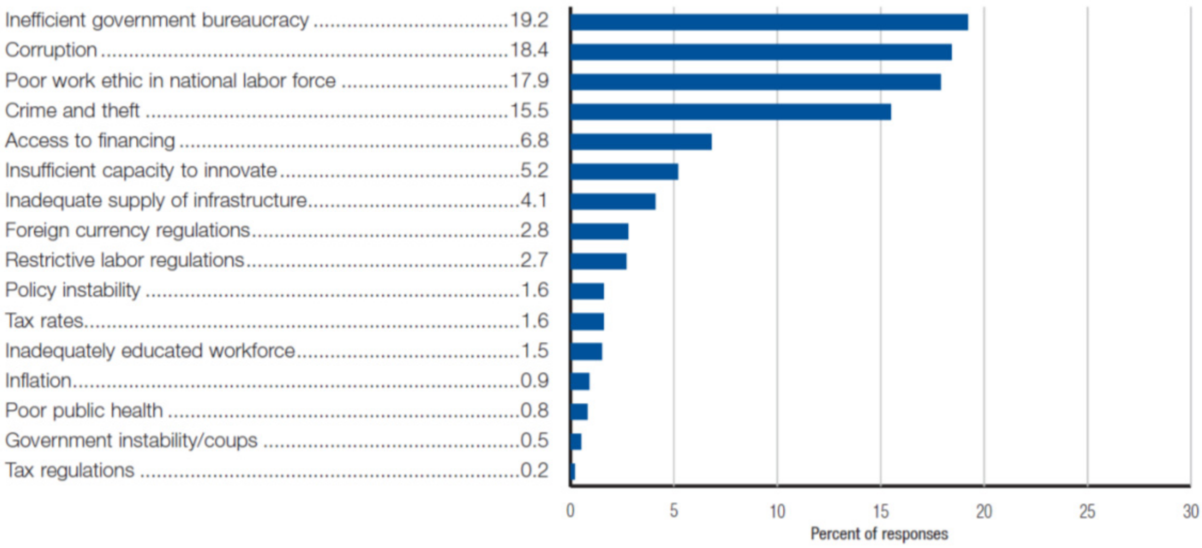
Score out of 7; Global Competitiveness Report 2014-15, World Economic Forum



The country profile for T&T lists the most problematic factors for doing business (Figure 17-7).

Figure 17-7 The Most Problematic Factors for Doing Business in T&T

Global Competitiveness Report 2014-2015, World Economic Forum



GORTT is undertaking various development initiatives to improve T&T's competitiveness, which are set out in the "Enabling Competitive Business Strategy 2011 – 2014" report, led by the Ministry of Trade, Industry, Investment and Communications (MTIIC) and the Ministry of Labour and Small & Micro Enterprise Development (MOLSMED). The Economic Competitiveness Board and Council for Competitiveness & Innovation were created in 2011 to advise the Ministry of Sustainable Planning and Development (MPSD).

Direct Investment

GORTT should consider working with the venture capital industry to encourage entrepreneurs and facilitate investment in business start-ups, perhaps via a "T&T Innovation Fund" established to run in parallel with VC funding. This could include helping universities to attract world-class research and teaching staff and to commercialise promising areas of research. Access to venture capital would also improve T&T's competitiveness[7].

GORTT could also invest to create the infrastructure for knowledge-based businesses and has in fact already created the Evolving Tecknologies and Enterprise Development Company Limited (e Teck) for this purpose. e Teck led development of the Tamana InTech Park, located 18 km NE of the international airport; Phase 1 of this science and technology park was completed in June 2014. Tamana is intended to be a model for future development and partners with the University of Trinidad & Tobago (UTT), which will be the Park's largest tenant.

17.4.4 Industry Clusters

Over the years energy sector production facilities have been established on the west coast of Trinidad – the major centres being at Point Lisas, Pointe-à-Pierre and La Brea/Point Fortin – forming energy-related industry clusters.

The concept of "business clusters" already forms part of the development strategy, and is being promoted through five "growth poles" where development is prioritised, of which four are in Trinidad – Central, the South Western Peninsula, East Port of Spain and the North-Coast – and one in the North-East Region of Tobago. The areas where the non-energy sector can most readily be integrated with the energy sector are the Central and South Western Peninsula areas where the energy industries are located.

Industry clusters offer a range of economic and planning advantages, such as:

- **Shared infrastructure**: Infrastructure can be shared among several plants – e.g. tankage, jetties, power generation, firefighting / emergency services and water supply, cooling water, hydrocarbon pipelines.
- **Technology integration**: For example, supply of CO_2 from ammonia plants, where it is produced as a by-product, for the production of methanol.
- **Economies of scale**: Secondary industries can develop economies of scale based on processing the products produced by the primary industries and might consolidate feedstock from several plants to achieve that.
- **Shorter supply chain**: The close proximity of plants within a cluster minimises the cost of feedstock delivery, e.g. by pipeline.
- **Critical mass for service industries**: Service industries can also achieve economies of scale, which supports specialised R&D, education and training. Clusters can also lead to innovation and rapid dissemination of ideas among the local industry as workers are more likely to move jobs locally and take knowledge with them.

[7] T&T was ranked 109 out of 151 economies for venture capital availability in the World Economic Forum's 2014-15 Global Competitiveness Index.

- **Minimising environmental impact**: By concentrating industry, a nation minimises the population affected by environmental impacts from the visual, noise and atmospheric impacts of the industries.
- **Safety and security**: Security can be implemented more efficiently with a smaller footprint, and the concentration of industries allows mutual support and sharing of safety and other equipment – implemented through Emergency Response Plans and HSSE Coordinating Committees – and simplifies the provision and specialised training of emergency services personnel.

17.4.5 Conclusions & Recommendations

T&T already has a vision and strategic planning framework to guide its future development. The issue today is its implementation. The public sector (ministries, agencies, state-owned companies) organisation could probably be better structured and coordinated to avoid duplication of effort and ensure that responsibilities are clearly assigned. The impression given is that whilst the policy framework is very good, the institutions responsible for implementation are not clearly accountable and concrete action plans do not yet appear to be in place – this may be explained by the fact that relatively the NSDS was developed only recently (2014).

18.1 CONCLUSIONS

18.1.1 Overall

- The gas sector is critical importance to the T&T economy. The actions taken in terms of policies over the next decade will have a profound impact on the financial state of the country and all policy development will need to be carefully considered.
- Natural resources are finite and subject to depletion, they are by definition not sustainable. They represent part of the capital stock of the country and the monetisation of these resources should be for the benefit of the country.
- The Gas Master Plan provides the route map for gas sector development over the next decade. As the gas sector is now moving into a mature phase, it is clear that GORTT focus for this master plan period will need to be one of encouraging incremental gas supply and the maximisation of the value to T&T from the gas produced.

18.1.2 Upstream

18.1.2.1 Gas Supply & Security of Gas Supply

- The relatively low exploration success in the last decade has resulted in a decline of deliverability from producing gas reservoirs as larger fields deplete and increasingly small and marginal fields are brought onstream to fill the supply gap. The decline in available deliverability over recent years has led to increasingly frequent supply shortages to both NGC and ALNG.
- The contractual structures for gas supply to NGC were developed during a time of gas surfeit when flexibility in volume offtake was required by downstream users. The flexibility has now become a problem for NGC in the face of constrained supply. The absence of penalties imposed on suppliers for shortfalls in contracted gas deliveries appears to have led to a disproportionate curtailment of gas supply to NGC by upstream suppliers in favour of ALNG in times of shortfall.
- There is no requirement or financial incentive for suppliers to maintain excess deliverability (swing or cushion gas) which would allow them to compensate for supply reductions in other parts of the production system.
- As the gas system approaches the end of plateau production, deliverability will depend on depleted mature fields and an increasing number of small field developments which will typically have high depletion rates and limited excess deliverability.
- Gas storage is unlikely to be a solution to the security of supply issue for a gas industry that has little seasonal and diurnal fluctuation. Studies undertaken by NGC indicate show that such a project would have limited impact upon managing supply. The fundamental issue for T&T is to mobilise investment on increasing offshore deliverability in order to avoid shortfalls occurring, as swing gas will be less costly than storage.

18.1.2.2 Gas Infrastructure

- There is adequate capacity in the gas transportation system but it is ageing and will require continued investment to ensure integrity.

18.1.2.3 Gas Reserves

- The total proven natural gas reserves in T&T have been in decline over the last decade as the rate of reserves additions has failed to keep pace with production. Proven reserves peaked in 2002 at approximately 20.8 Tcf but had declined to 12.2 Tcf at the end of 2013. The total unrisked proven, probable and possible reserves base is 23.9 Tcf. The R/P ratio for proven reserves was 8.3 years at the end of 2013 down from around 20 years in 2004. The diminishing R/P ratio indicates a need to focus on encouraging exploration.
- Much of the prospective resource volumes are in small fields, an expected 6.3 Tcf across 151 prospects with an average success volume of 250 Bcf. The prospectivity of many of these fields will depend upon their proximity to existing infrastructure and securing access to that infrastructure.
- A review of operator development plans indicates that gas supply rates of circa 3.85 Bcf/d (average) are likely to persist in the coming years and are a realistic expectation of future supply. This equates to a sales gas figure of ~3.7 Bcf/d, i.e. .there will not be sufficient gas to reach the ~4.3 Bcf/d required to fully supply the downstream industry. Beyond 2017 gas supply is increasingly dependent on offshore projects which are as yet not sanctioned for development. The heavy reliance on post-2017 unsanctioned projects emphasises the importance of rapidly getting these projects to sanction.
- The timing of any supply from cross-border fields which extend into Venezuelan territory relies on the outcome of government to government discussions. Only 27% of the largest field (Manatee Loran) lies in T&T waters but for any significant extension of plateau production the entire field would need to be processed through T&T infrastructure
- A combination of moderate deepwater success and some gas production from cross border fields would provide support to extend plateau or reduce the rate of production decline post 2025. If there has been no deepwater exploration success by 2018 or significant progress in cross-border discussions with Venezuela by 2020 then the industry should prepare for a further decline in long-term gas supply levels.

18.1.2.4 Mobilising Production

- Our economic analysis indicates that incremental and new developments under older PSC terms and shallow-water greenfield projects and incremental projects will require fiscal assistance and/or gas prices in excess of $3/MMBtu.
- Access to production and transportation infrastructure will be a key issue in mobilising incremental development the need for which will only increase as production from the shallow-water area continues to mature. Existing pipeline networks cross a significant number of open acreage blocks. Interest in exploring these areas would be increased if there was greater clarity on the terms of access to existing infrastructure in the event that exploration of those areas proves successful.
- The key challenge for T&T is to incentivise enough exploration activity in deepwater blocks in an early enough timeframe to ensure that any gas present is developed in time to backfill the shallow-water production profile. Success in the first work period would encourage operators to pursue subsequent phases but current contracts would deliver a maximum of only 22 wells over the full exploration program. This is an area where GORTT should stimulate additional activity.

- Supply from the cross-border fields relies on the outcome of government to government discussions which have been in progress for many years. The emergence of gas supply shortages in recent years, together with the understanding that even the current reduced production plateau will not extend beyond 2025, has provided a clear imperative for T&T to progress these discussions towards an agreement to develop the gas. There is a window of opportunity to process gas through existing consumers as shallow-water gas production declines in the mid-2020s.

18.1.3 Downstream

18.1.3.1 Markets

- T&T has developed a major gas export industry both directly, in the form of LNG, and indirectly through gas-based petrochemicals (ammonia/urea, methanol). The sale of these products collectively account for ~86% of the gas consumption in T&T of which ~55% is utilised in LNG.
- The market demand for these products are continuing to grow but T&T's competitive advantages (the low cost of the gas resource and the proximity to the world largest market, the US) have been eroded over time as incremental gas supply from T&T has become more expensive and the US market is now saturated with gas. T&T petrochemical exports will be competing for market share against products from other supplier countries in more distant markets.
- GORTT has elected to provide power at a highly subsidised price as a means of distributing the wealth generated from the energy sector to the wider population. RIC sets the price at which T&TEC sells power to different classes of consumer. In order to sustain T&TEC financially NGC sells it gas at a current price of around $1.35/MMBtu, with inflation escalation. This has caused major distortions in the gas value chain as the price is below the economic cost of production of many of the upstream suppliers. This situation is managed by NGC. This is problematic; the low price of power does not encourage energy efficiency. The low gas price also diminishes the incentive and the ability of T&TEC to invest in more efficient generation capacity.

18.1.3.2 Commercial Arrangements & Value Generation

- Over the last decade GORTT has derived the greatest benefit from its natural gas resources through ammonia exports. The returns from LNG have been relatively poor compared to those from ammonia and, to a lesser extent, methanol. The relatively poor performance of LNG has not been due to inherently poor market conditions but rather from the particular marketing arrangements that have been in place for LNG. Under different arrangements GORTT take from LNG would have been at least as high as from ammonia. Given the relative size of LNG exports it is clear that improving the value from LNG should be a high priority for GORTT.
- GORTT realises significant economic rent through the aggregation role played by NGC in supplying the downstream.
- Netback prices from existing LNG arrangements are projected to remain relatively low. However, based on our price projections and under revised LNG arrangements post-expiry of existing contracts, LNG is could be the most attractive of T&T's existing gas monetisation

options. The expiry of the existing ALNG Train 1 agreements in 2019 presents an opportunity for the GORTT to realise this potential value.

18.1.3.3 Gas & Supply Demand Situation

- The overall gas supply to downstream industries has declined somewhat since peaking in 2010. This has been due to lower supply from upstream producers due to reduced deliverability and protracted maintenance periods. As a result all export-based industries have seen gas supply availability declines.
- NCG appears to be in a comfortable position in terms of contracted gas supply. However, actual supply to NGC from upstream (~1.6 Bcf/d in 2014) has been well below contracted supply (~2.1 Bcf/d).
- A key issue is that although all major downstream industries have experienced declining gas supply availability, overall gas supply to LNG has largely been maintained at contractual levels (average supply was around 2% below contracted levels of ~2,212 MMcf/d for ALNG in 2011, 2012 and 2014) while overall gas supply to NGC has not. This in turn has left NGC short of gas to supply its downstream customers.
- T&T has a current downstream portfolio that could consume an estimated ~4.3 Bcf/d. This demand is presently not being fully met and based on our supply demand analysis it is not realistic to expect that it will be met in future on a long-term basis (under the most optimistic supply forecast demand could be fully for a period of ~3 years from 2019). Indeed the current shortfall situation will continue.
- If production from presently unsanctioned developments under the most recent PSC terms is mobilised there would be sufficient gas to meet downstream contractual commitments, but not to meet demand. These projects would also only provide limited volumes/durations for expiring downstream contracts to be extended from 2019. Extending expiring downstream contracts well into the 2020s will require substantial unsanctioned production under the more economically-challenged old PSC terms.
- While gas supply is likely to available from 2019 to extend supply contracts to existing downstream industries, it is highly likely that gas supply will be insufficient to fully meet demand and as such decisions will have to be taken over which contracts to extend and which downstream industries to shut down. In the absence of large volumes of incremental supply, directionally the gas sector will need to focus on arrangements to achieve higher gas prices and greater efficiency in the existing plant and production facilities, i.e. a focus on developing value rather than growth.
- Given the prevailing gas shortfall situation the development of new projects will need to be carefully considered. It is clear that the sanctioning of any gas supply to new downstream ventures will come at the expense of supply to existing operating assets, i.e. if a new plant is developed then it is likely that an old plant will have to be shut down. Old plants are amortised and in general the costs of investment in a new plant are likely to far outweigh the effects lower operating efficiency likely to be found in an older plant.
- The shortfall situation the NGC experiences in supply from the upstream is passed on to the downstream and is managed by NGC by applying generally pro rata cuts to the downstream industries, but maintaining supply to the domestic sector. Contractually NGC avoids penalties in contracts by declaring Force Majeure.

18.1.4 Future Mid & Downstream Sector

18.1.4.1 Prioritisation / Allocation of Gas

- Existing shortfalls have been managed by control of the gas supply split between NGC and ALNG by bpTT and to a lesser extent BG, and NGC managing the supply to its downstream industries (generally) imposing cuts on a pro rata basis. NGC's position has been that gas supply shortfalls are short-term phenomena and that following a shortfall there will be a reversion to full supply. Indeed expiring downstream contracts have been renewed by NGC at their existing ACQ levels. The existing contractual shortfall situation through to at least 2016 and its potential future extension is such that there will be a need for active management of supply into consumption.
- GORTT should be seeking to maximise the value received from the gas produced, which in an environment where demand cannot fully be met means directing gas towards the plants that offer the highest value for the resource. This is not happening under the present system of all contracts being extended without apparent analysis of their relative value to GORTT.
- There are interventionist approaches that GORTT could potentially take to manage the contractual shortfall situation by diverting gas to higher value end users, although the parties impacted may not be willing to accept such moves and may contest them legally.
- Given that it would not appear feasible for NGC to extend any of its contracts that expire before 2019, a more selective approach to downstream contract renewals will inevitably be required in future. GORTT has several options ranging from a market-based approach through to central planning.

18.1.4.2 Sectoral Structural Issues & the Role of NGC

- NGC is the only, player in the midstream sector and covers a multitude of roles, not just in the midstream but across the whole hydrocarbon sector: monopoly wholesaler / aggregator; transmission owner / operator; owner of E&P, LNG and gas processing assets; LNG offtaker; and gas industry business development.
- There are issues related to the existing roles of NGC; no formally defined regulation of NGC; potential conflicts of interest, lack of transparency, aggregation management proving increasingly challenging; the overall GORTT know-how of the sector is highly concentrated in NGC.
- There are a number of options for GORTT for managing the structure of the sector and the role of NGC: no change; NGC wholesale role expands to include LNG (from expiry of existing contracts); NGC business refocused on core activities (wholesaling and transmission); allowing bypass of NGC for large buyers; unbundling transportation services; and fully liberalising the market. However, the depth and breadth of the T&T gas industry is not sufficient for the development of a competitive market.
- From GORTT's point of view the key factor that must be considered is the significant economic rent captured by NGC in the midstream and ultimately distributed back to GORTT as a dividend. If the wholesale margin was passed back to upstream then GORTT would have to share the upside with the upstream suppliers as per the terms of the various upstream agreements.
- Poten's view is that the uncertain benefits associated with a significant restructuring of NGC's role as wholesaler / transporter are unlikely to be justified by the potential reduction

in GORTT take, the challenges associated with maintaining existing GORTT take levels under a new structure (e.g. by imposing new taxes), and the time and cost associated with implementing what would undoubtedly be a major restructuring exercise. As such we do not believe that allowing the bypass of NGC, unbundling NGC's transportation activities, or fully liberalising the sector will be optimal routes for GORTT to follow.

18.1.4.3 Options for LNG

- GORTT capture of economic rent from LNG has been far less than for the NGC-supplied ammonia (in particular) and methanol plants, with substantial value leakage offshore, i.e. beyond the T&T tax net.
- Although there may be options for GORTT to improve its share of the overall LNG chain take under the existing contractual arrangements, the main forthcoming opportunity for it to do so comes with the expiry of the existing ALNG Train 1 contractual arrangements in 2019. There are a number of different options that could be considered for various elements of the value chain. The key issue to address is the marketing arrangements for LNG.

18.1.5 Institutional Issues

18.1.5.1 Policy

- There is at present no approved policy covering the gas sector for the master plan period. The MEEA draft Green Paper sets out the objectives for the energy sector and has a number of policy goals related specifically to the gas sector. However, it is not a GORTT-approved document.
- The local content policies developed in T&T are focussed on placing contracts with T&T entities rather than on local value added. There is an absence of visibility to ensure compliance with objectives for local participation in the energy sector and a lack of monitoring and auditing of local content targets. Overall, local content policies are not integrated in GORTT's regulatory activities of the sector and specifically, there is an absence of a well-defined monitoring and measurement system that focusses on local value added.

18.1.5.2 Sector Regulation

- The GORTT lacks an effective institutional and regulatory framework for administering the natural gas subsector. The main piece of legislation was adopted in 1962 to regulate the exploration and production of crude oil. Technical licensing regulations have been adopted for natural gas facilities, but no oversight is applied to commercial monopolies and supply obligations. Information on the amount of revenue derived from the natural gas subsector is not separately accounted for.

18.1.5.3 Fiscal Regime

- The fiscal terms in T&T have evolved significantly. In the 1970s PSCs were introduced in addition to existing EPLs. Under the PSC regime, GORTT take was based on the allocation of a share of production thresholds rather than the fixed royalty under the EPL. This mechanism was changed in the 1990s to a 'matrix' that takes into consideration prices as well as production levels. The increase in state-take under the PSC was off-set by a provision that committed the Minister to pay royalties and other taxes assessed on PSC operations from his share of the profit petroleum.

18.1.5.4 Institutional Capacity

- The next 10 years for the T&T gas industry will be a period where there will need to be significant intervention by the GORTT in both upstream and downstream sectors. This will impose a significant burden upon MEEA, an organisation which is already facing challenges in retaining qualified personnel to manage the affairs for the state.

18.2 RECOMMENDATIONS

18.2.1 Upstream

18.2.1.1 Gas Supply and Security of Supply

- For new upstream supply contracts NGC should ensure that there are "failure to deliver" clauses so that suppliers are obligated to supply a given volume and will be penalised if they fail to do so. However, it is noted that continuity of supply has a value that has not to date been reflected in the gas prices and that higher prices are a corollary to this action.
- Supply interruptions have increased in recent years as the deliverability of large foundation fields falls as they are depleted. While new fields have been developed to replace lost production capacity, they are smaller and do not have the large excess well capacity of the larger fields. The newer fields are therefore unable to make up for temporary supply shortfalls elsewhere in the system due to planned and unplanned shutdowns. The impact of planned shutdowns can be addressed to some extent by better planning of maintenance programmes between producers to avoid too many production sub-systems being off line for maintenance at any given time. However, the system will still be exposed to unplanned shutdowns. The underlying cause is a system-wide reduction in deliverability as older prolific fields are replaced by smaller fields with less spare deliverability. Increasing system deliverability requires investment, primarily in additional wells or field compression, given that gas treatment and transportation systems have demonstrated sufficient capacity in the past. This could take the form of accelerating current development plans to increase short-term production capacity before existing fields decline. Producers can be incentivised to do this by:
  - Requiring excess deliverability in new supply.
  - Offering an additional tariff for maintaining reserve capacity.
  - Paying a premium for uninterruptible gas.

18.2.1.2 Mobilising Upstream Development

- Maintenance of a plateau production rate of 1.4 Tcf/y (3.85 Bcf/d) requires that a high proportion of unsanctioned projects proceed as planned. A hybrid approach to this goal is recommended, consisting of an initial realignment of fiscal and other regulations to remove inconsistencies between terms awarded over the last two decades, combined with flexibility for the regulator to provide support to specific developments that cannot progress even under the revised terms. The initial realignment of regulations should include:
  - Maximising access for new developments to existing infrastructure to reduce costs.
  - Review and updating of fiscal terms (covering profit split and cost recovery) in 1996-05 gas price indexed PSCs to provide new developments with terms similar to the 2011-12 PSCs.
  - Review and updating of fiscal terms in production license areas to ensure they provide a comparable investment return for new projects to recent PSC terms.

- A transparent and easily administrated approach will also be required to the application of incentives for fields that remain marginal covering both additional fiscal support and flexibility in offered gas prices. This will require case-by-case assessment of the merits of marginal projects.

- In regard to deepwater developments the focus for T&T at this stage should be to expand the number of blocks under license with firm drilling commitments. This will be challenging in the current environment of reduced expenditure across international oil and gas companies, however opportunities for stimulating increased activity should be explored including:
  - State-sponsored seismic acquisition.
  - Review of fiscal terms and alignment between GORTT and operator incentives.
  - Road shows to advertise new fiscal terms and seismic data.

- In regard to cross-border gas it is recommended that further initiatives are taken:
  - Setting clear deadlines and timelines within GORTT for progress of the discussions with Venezuela.
  - Comprehensive evaluation of the value to T&T of securing an arrangement whereby 100% of produced gas is processed through their existing infrastructure, to allow specific value propositions to be formulated and when appropriate presented to the Venezuelan government.
  - Consideration of how agreement to develop the gas reserves could form part of a broader bilateral agreement with Venezuela.

18.2.1.3 Access to Infrastructure

- Access to existing infrastructure will be essential to mobilise incremental resources. The challenge for the regulator is to create the conditions in which spare capacity in existing upstream infrastructure is made available to other developers under reasonable commercial terms to stimulate exploration and production investment. The success of the relatively unintrusive UK North Sea approach of an Industry Code of Practise, supported by a regulator willing to intervene in the national interest in exceptional circumstances, presents a compelling model for T&T. This regime relies on negotiation of commercial arrangements between the infrastructure owner and the third party for access with the threat of government intervention if terms cannot be agreed. It is considered that this can be implemented without changing existing legislation and that GORTT intervention could be enforced where necessary under the rule-making authority granted to the President either by direct regulation under Section 29 (1) (c), or by delegation to the Minister under Section 29 (1) (o) of the Petroleum Act.

18.2.2 Downstream

18.2.2.1 Markets

- GORTT should establish a power price that at least reflects the cost of service of supply. This would encourage more efficient energy use and bring greater revenues to T&TEC. In the short term it would reduce the amount of power required and the amount of feed gas and in the longer term provide the incentive and ability for T&TEC to invest in more efficient generation capacity. Regarding the subsidy, it would be more effective for GORTT to more directly target the poor by making direct payments through welfare support or, as a second best option, limiting the amount of electricity that qualifies for the low electricity price. Users consuming more than the qualifying amount would pay a higher price on the excess, which should be set at a level to cover the cost of the subsidy.

18.2.2.2 Commercial Arrangements & Value Generation

- GORTT market focus should initially be on attempting to improve the value received from LNG exports. Although recognising that there are existing commercial arrangements in place MEEA should:
  - Undertake a detailed review of the project contracts and LNG marketing arrangements to see where action could potentially be taken. For example, there may be terms in the Project Agreements for the various LNG trains under which action could be taken to change the approach of various LNG offtakers, e.g. a requirement to maximise value under the LNG offtake arrangements. It will be necessary for GORTT to take legal advice on the extent to which any of the options identified are likely to succeed.
  - Investigate the possibility of tax authority action on realised prices. The Petroleum Pricing Committee has been identified as a potential mechanism to impose deemed pricing for tax purposes, bringing more revenue under the GORTT tax umbrella. This needs to be investigated further by MEEA. Again, it will be necessary for GORTT to take legal advice on the extent to which this is likely to succeed.
  - Stimulate LNG offtakers into action by putting the reality of T&T's take from the LNG industry into the public domain, or at least threatening to do so (the general perception in T&T appears to be that LNG provides very good value for T&T's gas and there does not appear to be any widespread awareness of the value loss issues that have been described).
  - Closely scrutinise future LNG sales to attempt to better hold offtakers to account where there appear to be deviations in value from prevailing market conditions. MEEA should insist that all ALNG revenue is reconciled on a cargo-by-cargo basis in the data that it receives from ALNG, so that it can be properly understood and evaluated. MEEA should also insist that any costs included in the LNG prices are fully itemised and explained such that they can be properly scrutinised. MEEA should undertake ongoing analysis of this data as it is received to understand where the main areas of value loss are versus prevailing market conditions, i.e. which offtakers, which contracts, which end markets etc. This will put MEEA into a stronger position to challenge the activities of the offtakers and possibly prompt revised marketing behaviour that is more in the interests of T&T.

18.2.3 Future Mid & Downstream Sector

18.2.3.1 Prioritisation / Allocation of Gas

- There are interventionist approaches that GORTT could potentially take to manage the contractual shortfall situation by diverting gas to higher value end users, although the parties impacted may not be willing to accept such moves and may contest them legally. GORTT needs to investigate the options available to it in dealing with shortfall management and the extent to which it is able to guide supply in a shortfall situation, including LNG and NGC's downstream portfolio. This will require a review of the conditions of each PSC, EPL, investment/project agreement, gas supply and LNG export supply contract to investigate such options, e.g. can the PSC TCM meetings be used to influence the gas supply split between NGC and LNG?, would the adoption of interventionist options by GORTT conflict with obligations under either the PSC or the EPL?, are there stability clauses in the PSCs that would limit GORTT's scope of action? GORTT will need to take legal advice on the likely consequences of implementing interventionist approaches to prioritise supply. For example, it will need to consult with the Office of the Attorney General regarding the application of T&T's jurisprudence on the nature of compensable property interests, if the parties affected could potentially claim a form of confiscation, expropriation or nationalisation.

- Following a commercial and legal review of the options for GORTT to intervene in gas allocations, GORTT requires a clear strategy during the transition period in which existing supply contracts direct with ALNG Trains 2-4 remain in force in parallel with the recontracting of supply to petrochemical consumers through NGC (and potentially ALNG Train 1). In particular this should address how supply shortfalls are allocated across old and new (Ship or Pay) contracts, i.e. can GORTT enforce supply diversion away from ALNG Trains 2-4 under the existing contracts in order to maximise its value from the gas sector, if this is deemed the optimal approach?

18.2.3.2 Future Downstream Contracts, Sector Structure & Role of NGC

- Rather than maintaining the status quo of direct gas supply contracting between upstream and ALNG, Poten's view is that, on expiry of the existing LNG contracts, NGC's wholesale role should be expanded to include ALNG, i.e. for new gas supply to ALNG NGC would buy gas from upstream and sell it to or toll it through ALNG. NGC would also continue this wholesale role for supply to methanol and ammonia. Although this is very much an interventionist approach, Poten's view is that this approach is likely to maximise GORTT's overall take from the sector in future, due to the significant economic rent that is captured by NGC in the midstream and ultimately distributed back to GORTT as a dividend. This expanded role would not compromise the ability of the sector to provide more attractive prices to upstream in order to support new developments as NGC would be able to provide LNG-linked pricing to upstream suppliers if this was deemed necessary to support new upstream developments. It could also provide gas pricing to upstream linked to a basket of LNG, methanol and ammonia prices.
- In addition, this option would allow NGC to manage gas supply to the whole downstream sector, whereas at the moment it has limited control of how much gas is supplied to LNG. This is of particular relevance in a gas shortfall situation
- Future gas contracting should conform to industry best practice with enforceable delivery obligations between NGC and both gas suppliers and buyers.
- Poten's view is also that NGC's business should be refocused on its core wholesale & transportation activities, i.e. its other non-core assets should be divested, potentially either to other existing or new GORTT entities, or to new publicly-owned vehicles. There is no obvious reason as to why NGC is the best undertaker of its non-core roles, such as sector business development, or the best holder of its non-core assets, e.g. upstream production, PPGPL. In particular, these roles create potential conflicts of interest for NGC's core role. This will allow NGC to operate without conflicts of interest or bias through a time when there will be many difficult decisions to be made in regard to the allocation of gas.
- NGC appears to have a history of reinvesting earnings for expansion of its commercial presence rather than dividending the revenue back to GORTT. Although this would be largely addressed by paring NGC back to its core activities, GORTT should ensure that NGC as a rule automatically dividends back surplus funds to GORTT. Extending NGC's wholesale role will also increase the oversight required of NGC's activities by GORTT to ensure that it is acting in the broadest interests of GORTT rather than its own more limited perspective.

- In parallel with expanding NGC's wholesale role to include LNG, Poten recommends that a centrally-planned, allocative approach to future downstream gas contracting is adopted. For the same reasons put forward for the future role of NGC, Poten does not believe that adopting the market-based approach will be in the best interest of T&T. Under the two centrally-planned approaches there are clear attractions to the tendering option which would potentially provide a transparent and fair price discover process. However, our view is that the obstacles to implementing this option (establishing tender parameters between different commodity producers and between plants with different contract expiry dates) will be very difficult to overcome in practice. This leaves the approach under which GORTT determines the downstream consumers that will receive gas as the only viable option.
- In terms of implementation, there will need to be an assessment made by GORTT/MEEA/NGC as to how much gas will be allocated to the key consuming sectors, e.g. LNG, ammonia, methanol and steel, as it is unlikely that there will be sufficient gas to fully satisfy demand. Within the determination of how much gas to be supplied to each sector GORTT/MEEA/NGC will need to decide which plants should receive an allocation of gas and which, if necessary, should be shut down. With its expanded wholesale role, experience of managing its existing downstream sales portfolio and share of GORTT's overall gas sector knowledge and expertise, NGC should be well-placed to provide the necessary analysis and recommendations to GORTT/MEEA on downstream gas allocations. However, there should be strict guidelines in place about how allocations should be made, i.e. maximising GORTT take from its gas resources, and GORTT/MEEA should have the ultimate decision-making power regarding any new gas allocations.
- GORTT/MEEA/NGC will also need to consider the potential allocation of gas to any new industries in parallel with its analysis of allocations to existing users. Given that there is existing unfulfilled demand for gas from existing amortised plants there is no justification for T&T to offer tax holidays or other incentives for new plants. They must be able to compete on full cost basis to be approved.
- In summary, Poten's view is that NGC should:
  - Continue to act as the monopoly buyer of gas from upstream, gas transporter and wholesale supplier of gas to the methanol and ammonia industries.
  - Expand this role to include gas supply to LNG on expiry of the existing gas supply/LNG sales contracts.
  - Be forced to divest its non-core assets, e.g. upstream production.
  - Be forced to automatically dividend back surplus funds to GORTT.
  - Provide the necessary analysis and recommendations to GORTT/MEEA on future downstream gas allocations, with GORTT/MEEA making any final decisions.

18.2.3.3 LNG

- Poten's view is that post-expiry of the existing contracts any future gas supply should be routed through NGC to provide an efficient route for GORTT to maximise its take from the LNG value chain.
- In terms of LNG marketing, Poten's view is that continuing with the negotiated contracts model is unlikely to provide the best value for T&T; it risks replicating the existing issues of out of the market price and offshore value capture. For the same reasons our view is that utilising a marketing entity is not likely to be an optimal approach. Tendering is a transparent and competitive process which ensures that the best price is realised for sales

over the period that is covered by the tender. It is also is gaining increasing traction in the LNG business as the number of market players, shipping / regasification availability, and overall liquidity increases. As such, Poten's view is that this is the route that T&T should follow for future LNG sales to avoid the issues under the existing arrangements.

- In terms of implementing a tender process itself, NGC (via its TTLNG subsidiary) has already accumulated substantial experience of short-term LNG sales via its Train 4 offtake. It should be relatively straightforward for NGC to utilise this expertise to oversee any future tendering process for sales from ALNG. Again, there would need to be guidelines in place to manage this, under the ultimate oversight of GORTT/MEEA.

18.2.4 Institutional

18.2.4.1 *Policy*

- GORTT through MEEA should establish a clear energy policy which contains specific objectives in regard to future gas sector development and operational activity for the next decade. The first step in this process is to prepare a new Energy Green Paper that should take into account the policy options and initiatives developed in the Master Plan. This document should provide a clear pathway forward identifying Government intentions in regard to the operation and oversight of the sector.

18.2.4.2 *Sector Regulation*

- With the exception of upstream exploration and production, the natural gas sector in T&T is largely unregulated and left to function under a series of commercial agreements that allocate production to either internal or external markets. If the gas sector were still expanding it would be prudent to consider establishing an independent regulatory function. However, given the specific problems that the industry will face over the next few years and recognising that MEEA is already short of experienced resources, the establishment of an independent regulatory function, the recruitment of competent staff and the development of processes and procedures over the next five years would be an immense challenge and is likely to be a major distraction for the most immediate tasks at hand such as mobilising incremental gas supply.
- At this point in time rather than attempting to establish an independent downstream regulator for the gas sector, as many governments have done, Poten recommends that MEAA should retain its current role in setting policy and establishing the standards for industry performance regarding competition, curtailment planning and facility access, and that NGC should maintain its role as aggregator and gas transporter. At the same time, administration of the gas sector requires that industry and GORTT are intrinsically linked through a competent authority (NGC) that can provide a more finely-tuned level of operational and market oversight.
- In recommending keeping NGC in this critical role of gate keeper and clearing house in the centre of the gas industry there are two critical conditions:
  - That the upstream and downstream interests currently held by NGC are divested, and
  - NGC's role of aggregator and transporter is performed as a statutory body. This approach is intended to ensure that gas trading and transportation functions are conducted according to clear rules, without the distractions of external political and commercial agendas that burden state-owned holding companies. NGC would report

to the Minister, who would be responsible for appointing its board of directors according to clear criteria for their experience and competence.

18.2.4.3 Institutional Capacity

- Given the increased burden that will be placed on MEEA / NGC and the difficulties faced in attracting qualified personnel from the industry, there will inevitably be a need to use outside expertise going forward in dealing with upstream and downstream issues. There is also the possibility of utilising secondees from the various operating companies in certain areas which are not commercially sensitive. A number of companies have indicated their willingness to support GORTT in this way.

A.1 SCOPE OF WORK

A.1.1 General

An overarching principle that must inform the development of the Natural Gas Master Plan 2014-2024 is that the natural gas sub-sector must be structured in such a manner so as to maximise the benefits that accrue to the citizens of the country from the exploitation and depletion of its resource. The Strategy must therefore provide a basis for the efficient and effective management of the gas sub-sector in a long-term sustainable manner.

A.1.2 Key Areas to be covered in the Natural Gas Subsector Strategy

The Consultant shall conduct a detailed study of the natural gas subsector of the energy sector of T&T. The strategy shall specifically address the following areas:

A.1.2.1 Natural Gas Resource Management

- The global natural gas perspective
- Exploration for natural gas – contractual arrangements and allocation of exploration acreage
- Deep-water – identification of developmental concepts that maximise recovery, minimise well count and maintain flexibility to react to dynamic change.
- Upstream portfolio development – review of current arrangements
- Security of natural gas supplies, which includes the feasibility of storing natural gas
- Prioritisation of the allocation of natural gas among industries
- A policy on the optimisation of the utilisation of natural gas
- A depletion plan for natural gas
- Technological advances in the sector
- Transmission system and transportation infrastructure – flexibility and optimisation

A.1.2.2 Institutional and Regulatory Arrangements for the Subsector

- An institutional and regulatory framework for the efficient management of the various segments of the subsector (upstream, transmission and downstream) which incorporates the following:
  - Fiscal regime
  - Taxation
  - Petroleum legislation
  - A framework for natural gas pricing , utilisation, term and renewals
  - Reassessment of Trinidad and Tobago’s competitive position
  - Management of planned curtailment
  - Gas Release plans and other H,S& E policies and practices
  - Location of gas-based industries
  - A framework encompassing resource availability, economic impact and social benefits for the evaluation of gas based industries

- Identification of skills gap in the local energy sector and the capacity in Education and training to address such deficiencies in the Ministry and the industry
- Local content / participation by local companies in gas based industries
- Development of Energy Services Sector

A.1.2.3 Market Development

Evaluate gas utilisation portfolios for gas-based investments, including petrochemicals and their derivatives, LNG, including small-scale LNG plants; CNG; plastics; metals; power generation and emerging technologies, such as floating LNG and hydraulic fracturing; in the long-term on the basis of the following:

- Optimum portfolio mix and project prioritization
- Growth prospects
- Net GoRTT revenues (upstream, midstream, and downstream)
- Sustainable employment and skills development
- Integration with non-energy sectors of the economy
- Downstream value-added industries
- Size, location and quality of the gas reserve/reserve/resource base
- Competitiveness of Trinidad and Tobago as an international location for these gas-based industries
- World economic outlook
- Sustainable development including environmental issues
- Efficient use of natural gas
- Optimum markets and marketing arrangements

A.1.2.4 State Participation in the Subsector

- Government's participation in all parts of the chain such as in the marketing of its share of gas under the PSCs and as an investor in downstream industries
- Policy on the utilisation of Royalty Gas
- The NGC business model
- The Role of the National Energy Corporation of Trinidad and Tobago Limited (NEC) as the facilitator of gas based industries

A.1.2.5 Guidelines and Recommendations

The Consultant will be required to present guidelines and recommendations on the legal, fiscal and investment approval processes to give effect to all the recommendations arising from the above.

Appendix B New Developments in Upstream Exploration

B.1 UTILISATION OF NEW UPSTREAM TECHNOLOGY IN T&T

B.1.1 Introduction

Although deepwater development is in its early stages of development in T&T, the country has been a relatively early adopter of a number of recent technological innovations in E&P, many of which are relevant to deepwater development. These range from new seismic data collection and analysis techniques to innovations in drilling and facilities management.

B.1.2 Seismic Acquisition

B.1.2.1 Ocean Bottom Cables

Ocean Bottom Cables (OBC) are formed of an assembly of vertically oriented geophones and hydrophones connected by electrical wires and deployed on the seafloor to record and relay data to a seismic recording vessel. The ocean bottom cable is laid on the ocean floor and remains static, unlike in traditional marine seismic acquisition where a streamer containing the hydrophones is towed by the seismic acquisition vessels. These systems were originally introduced to enable surveying in areas of obstructions (such as production platforms) or shallow water inaccessible to ships towing seismic streamers. More recently the technique has developed to allow multi source recording and the latest developments provide four component (4C) seabed systems to record shear wave (S-wave) as well as P-wave energy.

bpTT has utilised OBC for the collection of seismic data in the ECMA area. This technique is particularly useful in a development area such as the Columbus Basin, which is characterised by multiple stacked gas saturated sands which can distort sound waves. The ability to record and process a wide azimuth range of signals significantly enhances the resolution of the data set and the subsequent imaging of the sub surface.

Over the period 2011 to 2014, bpTT conducted the first commercial scale High Definition Ocean Bottom Seismic campaign, covering a total area of 1,000 km^2 and using five survey vessels. A particular innovation was the utilisation of multiple source vessels which allows the much faster acquisition of seismic data and provides better resolution data. This approach provides improved frequency content, fault delineation, steep dip-bed imaging and deeper signal penetration than vintage streamer seismic operations. bpTT state that the interpretation of the dataset delivered has not only added resources to existing fields but also helped to improve the understanding of new fields like Angelin.

Inevitably this form of seismic data acquisition is specialised and expensive to secure. bpTT managed costs by sharing a crew with their operations in the North Sea which enabled the crew to shuttle between T&T in the winter and the North Sea in the summer in order to increase production efficiency and save cost.

B.1.2.2 In-Well Seismic Data Acquisition

The use of in-well seismic sensors provide a constant reference point over the course of the years of 4D seismic activity; the calibration reference enables the operator to acquire far better comparative images from the seafloor cable system. Another advantage afforded by the sensors is production of a detailed image close to the borehole, improving upon the overall subsurface image.

In-well seismic sensors can also be used in passive listening for acoustic events to improve understanding of fluid movement, drainage efficiency, active fractures and formation compaction. They can be used in analysing reservoir connectivity between wells at a finer scale than possible using surface seismic.

The optical sensors are made of machined glass that withstands temperatures as high as 345 degrees and pressures as much as 20,000 psi. The sensors have no moving parts and no downhole electronic components, and unlike traditional electronic sensors, which are susceptible to vibration-induced failure, the optical sensors can handle high levels of shock stress without degradation or interruption of measurements.

In the last two years bpTT has conducted their first offshore in-well seismic pilot in T&T, using fibre optics and acoustic sensing. This technology has the potential to offer 4D seismic images, generating snapshots of the reservoirs over time. 4D seismic facilitates more efficient reservoir management.

B.1.3 Seismic Processing

B.1.3.1 Amplitude vs Offset Analysis (AVO) & Spectral Decomposition

These are two seismic data analysis techniques that can be used to better map horizons and identify fluid containing horizons. Early practical evidence that fluids could be seen in reservoirs came from the identification of bright spots on seismic sections, areas of high amplitude signals, which were first identified in the 1970s. These bright spots were often found to be caused by layers which contained gas. However gas was not the only cause of bright spots and over time a technique that provided a more reliable guide was developed through the analysis of the amplitude of seismic signals with different offsets, with signals with wider offsets giving greater amplitude where fluids were present in the reflecting layer.

Modern seismic reflection surveys are designed and acquired in such a way that the same point on the subsurface is sampled multiple times, with each sample having a different source and receiver location. The seismic data is then carefully processed to preserve seismic amplitudes and accurately determine the spatial coordinates of each sample. This allows a geophysicist to construct a group of traces with a range of offsets that all sample the same subsurface location in order to perform AVO analysis[1].

Spectral Decomposition provides a means of utilising seismic data and the Discrete Fourier Transform (DFT) for imaging and mapping temporal bed thickness and geological discontinuities over large 3D seismic surveys. By transforming the seismic data into the frequency domain via the DFT, the amplitude spectra delineate temporal bed thickness variability while the phase spectra indicate lateral geologic discontinuities. This signal analysis technology has been used successfully in 3D seismic surveys to delineate stratigraphic settings such as channel sands and structural settings involving complex fault systems.

Repsol has employed amplitude versus offset (AVO) and spectral decomposition (SD) techniques for direct hydrocarbon identification (DHI) in the Plio-pleistocene section in deepwater T&T prospects to help to quantify better the risk during hydrocarbon prospecting. These seismic technologies require the use of pre-stack and post-stack seismic data that has been processed for preserving relative amplitude and frequency spectrum. In order to understand and predict the seismic response for different fluid types and lithology, AVO and SD modelling based on existing well log information close to the study area was

[1] This is known as a Common Midpoint Gather (a midpoint being the area of the subsurface that a seismic wave reflects off before returning to the receiver) and in a typical seismic reflection processing workflow, the average amplitude would be calculated along the time sample, in a process known as "stacking". This process significantly reduces random noise but loses all information that could be used for AVO analysis

performed. The controlled synthetic models simulated the seismic response for wet sands, commercially saturated gas sands, and partially saturated gas sands, as well as variations due to lithology. The fluid substitution was performed using Gassman's equation after proper petrophysical analysis and invasion/dispersion corrections were done on the well data.

After modelling and validation of the technique with real pre-stack and post-stack seismic data on calibration well locations, seismic analysis supported with AVO and SD technologies was performed to evaluate prospects.

B.1.4 Drilling

B.1.4.1 Sand Consolidation

Historical analysis of industry drilling and completions performance indicates a very significant gap between today's results and the technical limit in areas such as non-productive time and well failures, and hence production deferrals. This is particularly the case in sand-prone reservoirs. Many of these losses are tractable through better use of real-time data, although the technology for obtaining and analysing these data is still in its infancy.

Much of T&Ts production comes from sand-prone reservoirs. If sand enters a well after it has been completed, it can erode and damage equipment and cause loss of production. There are various sand-control solutions that have been designed to enhance the productivity and reliability of wells in these sand-prone reservoirs.

BP has developed predictive models that help drilling and completion engineers decide whether sand-control solutions are needed. The models use formation and production data, and can factor in the impact of using subsea equipment or production techniques (such as water flooding) that improve recovery. These models have been used in production planning in Angola, Azerbaijan and the GoM, as well as T&T. The models have also been used to determine the best approach for sand production in older fields such as the North Sea, to ensure field life is maximised.

bpTT is trialling a new chemical sand consolidation technology in T&T, which will be the first in the basin. This technology has been successfully used in sand-prone developments in the GoM and it is hoped that it can deliver lower cost, lower risk interventions that will keep wells online for longer. Success in this area would reduce effective reservoir development costs, and hence have the added benefit of unlocking more marginal pool sizes.

B.1.5 The Digital Oilfield

Digital oil field is an umbrella term for technology-centric solutions that allow companies to leverage limited resources. For instance, such technology can help employees more quickly and accurately analyse the growing volumes of data generated by increasingly sophisticated engineering technologies, such as downhole multiphase sensors, measurement-while-drilling (MWD) applications, multilateral completions, and downhole separation.

The digital oil field encompasses the tools and the processes surrounding data and information management across the entire suite of upstream activities. Specifically, digital oil field technologies allow companies to capture more data, with greater frequency, from all parts of the oil and gas value chain and analyse it in real or near-real time, thus optimising reservoir, well, and facility performance.

Typical technologies that are receiving universal industry acceptance include:

- Remote Real-Time Facility Monitoring and Control - Offsite control of facility process systems through the networking of SCADA (systems control and data analysis) and its transfer to onshore control rooms, enabling field data capture, set point control, and valve/pump manipulation.
- Real-Time Drilling - The collection and integration of real-time drilling data such as RPM, circulation solids, downhole pressures captured through MWD, and remotely steerable downhole tools.
- Real-Time Production Surveillance - The utilisation of advanced alarm systems to trigger analysis of important production integrity trends to help optimise and maintain installed capacity levels.
- Intelligent Wells - Surface-controlled, downhole equipment, enabled by fibre-optic sensors, allows for continuous monitoring of conditions and response.
- Remote Communications Technology - Offsite facilities with real-time visual, voice, and data communication with the field allow more rapid, analytical responses by a mix of offsite and onsite staff.
- Integrated Asset Models - Applications that model complete production system performance from the producing horizon, through the wellbore, through the production facility, and onto the export/sales point across disparate data sources and multisite work teams.
- Workflow and Knowledge Management Systems - Robust historical data and document management solutions that allow assets and functions to quickly execute workflows and routines by calling up complete historical analyses quickly and accurately.
- Production Volume Management Systems - Standardiaed production data and production allocations, allowing more efficient real-time production decisions that result in reduced deferment and improved operational integrity.

BP is one of the industry leaders in developing the ‘digital oilfield’ through their “Field of the Future” technology programme, which began almost 15 years ago. At the programme’s outset, digital was shorthand for connectivity and collaboration. The company has invested in fibre communications technology and established monitoring centres based onshore, which enable experts to see relevant information from platforms in real time and talk to operators offshore, regardless of conditions. The company has also invested in the software and hardware needed to monitor operational integrity and carry out reservoir surveillance.

bpTT has introduced this technology in T&T over the last 5 years. In its T&T operations the company has sensors downhole, in its facilities and across its topsides, although they note that they are yet to realise the full value inherent in the data they are obtaining[2]. A recent development by the company in T&T is the Casing Running Console, as part of the Well Advisor portfolio of tools, first deployed in 2013. It uses sensors on the drill string to detect friction as the well is completed, and has been 100% successful globally in avoiding stuck pipe in more than 300 runs of 640 km of tubulars, monitored live to date. The estimated saving to date is $200 million through reduced non-productive time.

[2] Shifting trends in Upstream Technology. David Eyton, BP Group Head of Technology. T&T Energy Conference January 2015

B.1.6 Asset Optimisation Systems

bpTT utilises various optimisation systems to manage its T&T operations. The T&T field optimiser (TFO)[3] is an offline advisory system that links to real-time data sources as well as to modelling and simulation packages to provide an overall representation of bpTT's gas production and conditioning facilities. The company has embedded the tool into its operational decision-making processes, and its hydrocarbon value assurance team will employ it to analyse various real operating value realisation scenarios.

The system is intended to encourage cross-discipline communication by integrating subsea, offshore, and onshore facilities. It provides an understanding of the impact of field and process constraints together in production potentials and capacity utilisation, including available separation and transportation capacity, pipeline backpressure effects, well operational limitations, and onshore treatment constraints. The optimiser is intended to meet contractual obligations in the most profitable way, such as by producing the nominated gas quantities in a way that maximises the condensate revenue stream. It is also expected to provide an in-depth understanding of potential new field developments and of required changes in the operating philosophies to maximise investment value.

Adoption of the new technology is expected to improve operational productivity by allowing the gas dispatchers to eliminate guesswork with respect to daily optimisation, add additional revenue to the saturated gas business by operating more efficiently in maximising liquid hydrocarbon production while meeting gas nominations, and reduce the time to react to changes that affect normal operating conditions.

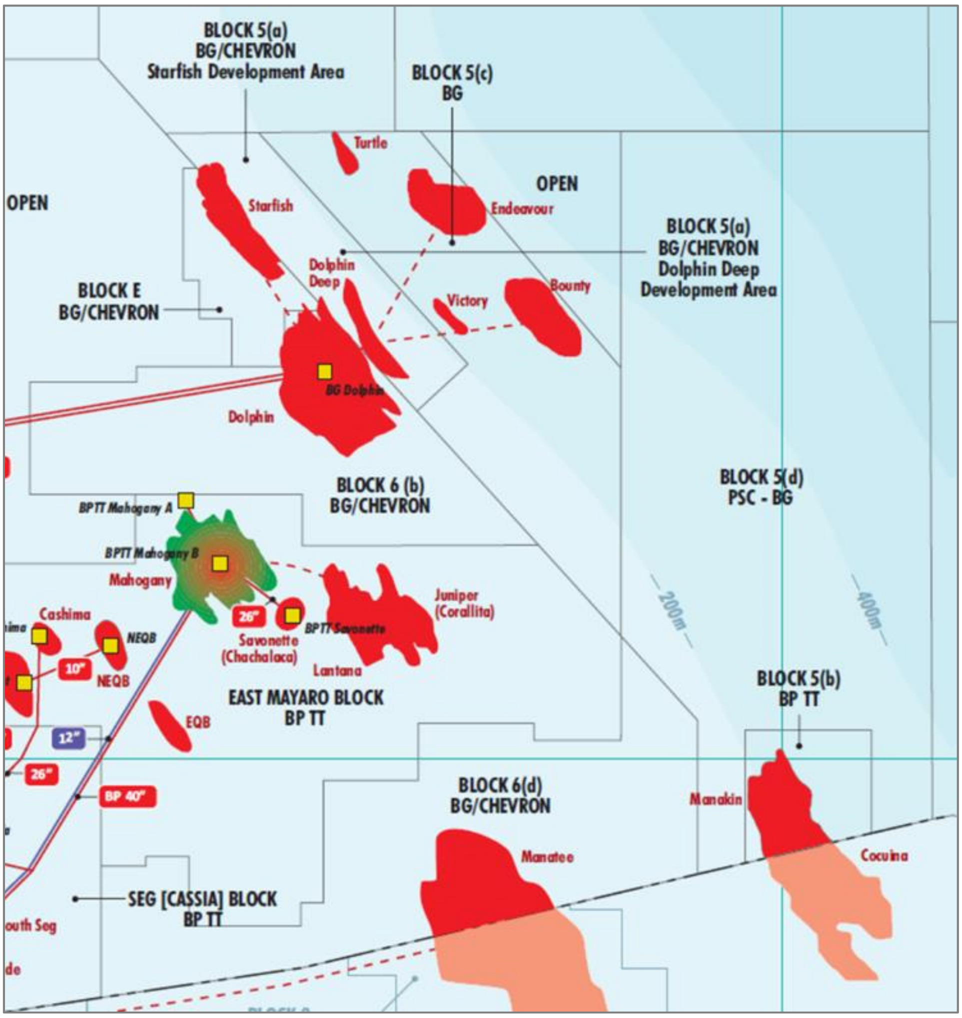
[3] Oil & Gas Journal 5th April 2009 Special Report: Asset Optimization — 1: Real-time data, models optimize complex production off Trinidad

B.2 REVIEW OF NEW TECHNOLOGY AND DEEPWATER CONCEPTS

B.2.1 Deepwater Development in T&T

Adopting a standardised definition of "deep water", we may note that the US Bureau of Safety and Environmental Enforcement (BSEE) website defines deep waters are those exceeding 1000 ft (305 m). Under this definition, two discoveries qualify as "deep water" - Endeavour and Bounty on BG's Block 5c, located circa 10 km east of the Dolphin field.

Figure B-1 Deepwater Boundaries in T&T
(source: Petroleum Economist)

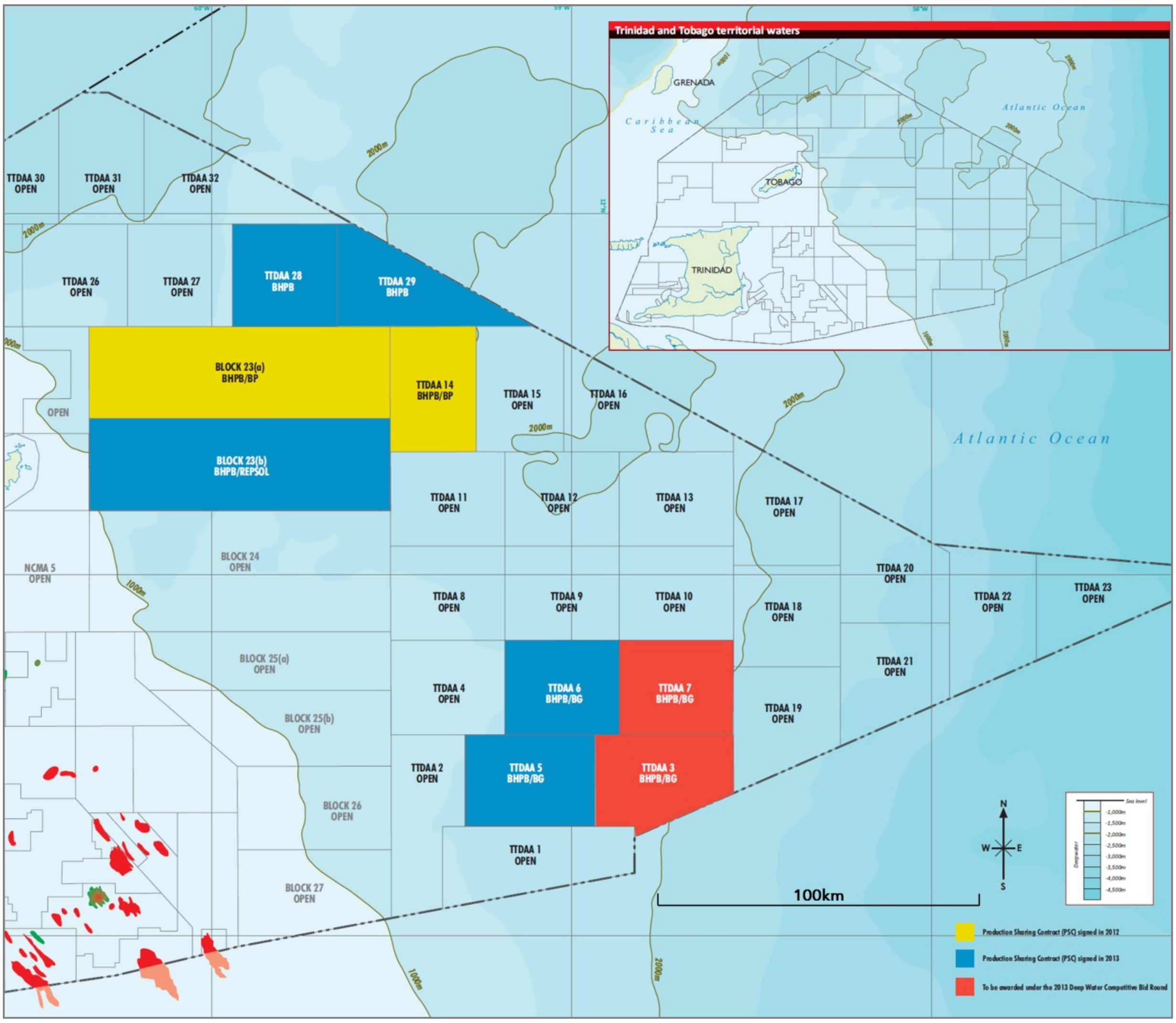


The appraisal and development of these reservoirs are slowly moving forward. No news has been posted on Endeavour since it was declared a discovery in 2009. The media (e.g., CaribX) had indicated that license area development would be advanced with the spud of the Bounty-2 appraisal well in the fourth quarter fiscal 2014 with first gas expected by 2018; however, recent data from BG has targeted the appraisal to occur in 2015 with first gas produced in 2019.

Both fields are currently presented by BG as simple 2-well manifolded tiebacks 90 km to the shore at Beachfield, bypassing the nearest infrastructure at Dolphin.

Figure B-2 Trinidad and Tobago Deepwater Area for Development

(source: Petroleum Economist)



In summary, though an 8 well exploration program was launched almost two decades back, there are no deepwater developments yet in T&T. Therefore, it is not possible to list the advantages or disadvantages of current deepwater developments for GORTT and contractors. Note also, while there are deepwater exploration activities in neighbouring countries (e.g., Guyana), there are no proven deepwater operating systems near T&T either.

GORTT has however released a significant acreage area to the east of Trinidad in water depths in excess of 2000 m. BHP, BP, BG and Repsol have signed PSCs on nine blocks since 2012 in the 1000-2000 m range, illustrated on the map above. While still in an early exploration phase these blocks present a development challenge against which deepwater development technology capabilities can be assessed.

B.2.2 Review of Deepwater Development Concepts

B.2.2.1 Subsea Tiebacks

Deepwater developments have numerous challenges, especially for long-offset and deepwater fields. High-cost platforms and spars can erode economics while field architecture favours fewer wells with extraordinary productivity spread out over larger sea floor areas. As a result, subsea tiebacks, and new innovations thereof, are becoming increasingly attractive. Even the fixed platforms and floating structures for gathering, initial processing and metering are giving way to seafloor mounted equipment, doing the same job, next to the field and with far less cost than fixed or floating support structure. Many E&P companies are turning to subsea tiebacks to link multiple wells to a single facility/hub, either their own or those owned by third-party operators, to enhance efficiency and economics.

T&T has established a massive gas production and transportation infrastructure in shallow waters lying conveniently between the majority of allocated deepwater license blocks and the onshore gas industry assets. All existing discoveries are well within proven tieback distances.

For future deepwater gas discoveries within 120 km of existing facilities, it will be worthwhile to evaluate all the potential tieback options as a base case. Regulatory and/or commercial barriers to tieback options should be eliminated or at least minimised.

Using simple subsea tiebacks to existing infrastructure (employing minimal new subsea technology) will minimise capital expenditure and risk; and, thus, will likely provide the greatest near term benefits to all parties. For long deepwater tiebacks (>40 km), provision for future installation of subsea compression equipment (once such are proven) may be a reasonable option for capturing long-term benefits at little extra cost. However, provision of compression facilities at existing hubs in moderate water depths is likely to provide sufficient hydrocarbon recovery while avoiding any technology risks for tiebacks within 60 km.

In general, standalone developments with new platform installations (even if placed in relatively shallow at the edge of the shelf) should only be considered if existing infrastructure cannot be used. However, for the deepwater blocks north and east of Tobago, installation of and tieback to new onshore or offshore facilities for gas processing and compression (in moderate depth waters) may prove to be a reasonable and well-proven alternative to extremely long tiebacks to existing platforms east of Trinidad.

The following issues should be addressed when deciding whether tieback to an existing facility is a viable option:

- The first question – "Is the new reservoir to be operated by the same oil company as the existing facility?"
  - If the operators are different, there will need to be a financial agreement to compensate the infrastructure owners for use of their facility, the cost of which must be borne by the new development's economics.
  - This can be an issue even if the new development and facility are operated by the same company but have different joint venture partners – or even different share participation among the same partnership. Agreeing the contract between owners of existing facilities and the venture developing the new field can prove to be an insurmountable obstacle. The owners of the existing facility will seek to take as much value from the new tieback as can be justified (or allowed by law), thus the

economic performance for even the simplest tieback option can be severely constrained.
- The infrastructure owners may feel a strong need to retain system ullage to accommodate their own discoveries – or even expected discoveries.

- Then, there are the technical questions:
  - Does the existing facility/infrastructure have sufficient residual lifespan for the new development?
  - Is the existing facility/infrastructure rated for the production pressure and temperature of the new development?
  - Does the existing facility/infrastructure have the capacity/ullage to produce the new field at an economic peak or plateau rate?
  - Is the existing facility/infrastructure suitable for the corrosive properties of the new fluid?
  - Are the topside processing facilities suitable for the new fluid properties (water cut, salts, emulsion, wax etc.)?
  - Is there space and/or payload capacity to fit new topside equipment on the existing platform?

In reality, the answers to these questions normally mean modification to the existing facilities and/or infrastructure as well as possibly undesirable limitations on the rate of production from the new development. There are solutions to most of these issues either by modifying the topsides equipment or designing the subsea system to suit the existing development.

One good example is the use of subsea HIPPS (High Integrity Pressure Protection System). This proven technology option works well when connecting wells with high pressure to an existing subsea flowline that has a lower pressure rating than required by the new reservoir. The HIPPS is an arrangement of automatically closing valves that are activated when the flowing pressure gets too close to the pressure rating of the existing downstream flowline.

Methods like this are effective but add cost to the new development. Modifying existing facilities and/or infrastructure to tie-in new equipment and the actual tie-in work comes at a high price. Not only do you incur the modification and tie-in costs but also the cost of the loss of production revenue from the existing development while it is shut down to allow the work to continue – this can be a very significant cost.

With the aforementioned aspects influencing the main decision, it is worth considering the specific features and factors that drive the details for the engineered designs which will ultimately be placed in service for tiebacks to existing facilities, starting with the configurations that tiebacks may take, then, reviewing the design criteria that influence complexity and cost.

B.2.2.2 Subsea Tieback Configurations

Figure B-3, Figure B-4 and Figure B-5 below illustrate different subsea tieback schemes.

Figure B-3 Simple, Single Well

- Direct single path flowline tieback
- Direct connection of control umbilical; may be simple direct hydraulics for short distances or complex multi-function (MUX) umbilical may include chemical injection flow path (e.g., for hydrate inhibition)
- Tree may be complex, supporting multiple zone completions

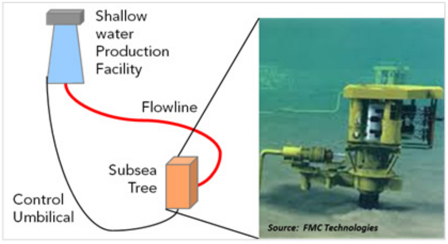


Figure B-4 Daisy-Chain Loops with Single Well Jumper Tie-Ins

- Single path flowline loop with "tee" connections laid in for jumper tie-in from subsea trees
- Complex control umbilical with functions split at Subsea Umbilical Termination Assembly (SUTA)
- Tree may be complex, supporting multiple zone completions

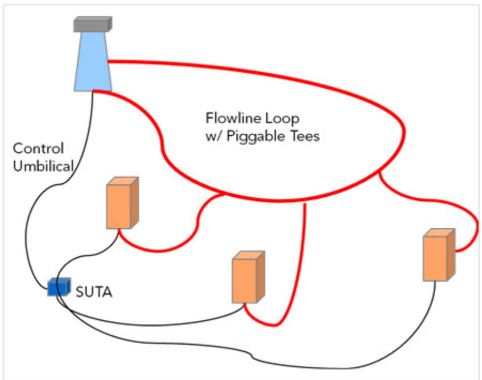
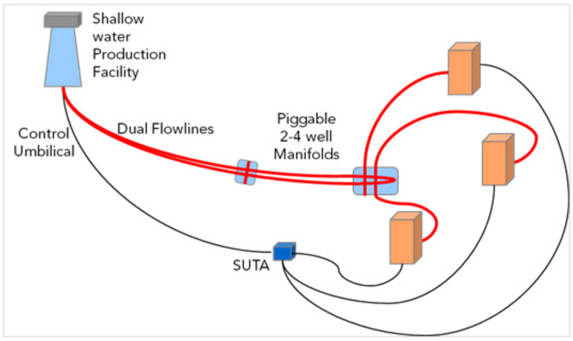


Figure B-5 Dual Flowline Piggable Tiebacks

- Common for multi-well tiebacks (clusters or templates)
- Very remote manifold skids may include subsea separation compression and/or pumping
- Separate power cable connection line would be needed if compression or pumping were to be added at remote manifold skid



Total's Kaombo offshore development currently in development in Angola is based on the use of the state-of-the-art "hybrid loop" technology for multiphase pumping and transport of fluids in water depths of 1,400 to 1,900 m.

B.2.2.3 Tieback Criteria

Flow Assurance

A very rich or condensate-prone gas flow stream can have great value, but also presents flow assurance challenges for longer-reach tiebacks. Sour and high toxicity gas streams increase costs and impair economic performance. In some cases, these contaminants may make it impossible for processing on/through existing facilities. To date, no sour reservoirs have been encountered in T&T.

Optimal deepwater flow assurance involves analysis and modelling of fluid behaviour within the reservoir, well, pipeline, surface facilities, and the surrounding environment. Regardless of the development scenario, accurate reservoir characteristics and fluid property information must be established to design the optimal production system from the reservoir to the topside facilities and from exploration to abandonment.

Clear understanding of fluid behaviour is of the utmost importance for flow assurance analysis, and representative reservoir fluid samples are essential to calibrate models of the production system. High-quality, single-phase, downhole samples for accurate flow assurance characterisation can be collected in open and cased-hole environments. Modern downhole reservoir testing uses wireless tool string communication to allow capture of a clean fluid sample to be acoustically triggered, in real time, from a surface computer during cased-hole drill stem testing (DST).

Samples are maintained at reservoir conditions to ensure the fluid remains intact for laboratory analysis - for example, maintaining the pressure and temperature to ensure waxes and asphaltenes remain in the fluid. Samples are validated and quality checked, with the best selected for flow assurance analysis. The gas/oil ratio can be established, as well as its composition and saturate, aromatics, resins, and asphaltene (SARA) contents. This is important for sample validity checking.

Particular attention is paid during the analysis to understand when the waxes and asphaltenes will drop out of solution, important for quantifying potential flow issues. It is also possible to predict when hydrates will form and cause blockages - all important considerations for system design.

Optimal flow assurance characterisation defines phase boundaries, and establishes the likelihood and extent of liquid and solid depositions in the production system, and the severity of the resultant blockages over time. Digital simulation tools for transient and steady-state conditions also can represent thermal hydraulic behaviour to determine whether, and what kind of, thermal management will be needed.

The ability to test organic and inorganic deposits in live reservoir fluids at field conditions is the most accurate way to determine fluid behaviour and can help reduce both capex and opex. Quantifying the effects of chemical additives on actual deposits under representative conditions contributes to efficient spending and reduces cost. Realistic organic solids deposition measurements improve the accuracy of systems modelling and completion designs. In turn, production operations can be optimised through better system design, chemical selection, dosage, and treatment. Pigging frequencies and remediation strategies can be improved, too.

The latest equipment can independently vary test parameters to quantify the effects of pressure, temperature, composition, surface type, flow regime, and shear on the deposition behaviour of organic deposits such as waxes and asphaltenes. Deposits can then be collected for testing and quantification. The deposit mass is used to calculate the deposition rate, based on the cell surface area and test run time, which can be scaled up to the field conditions through modelling.

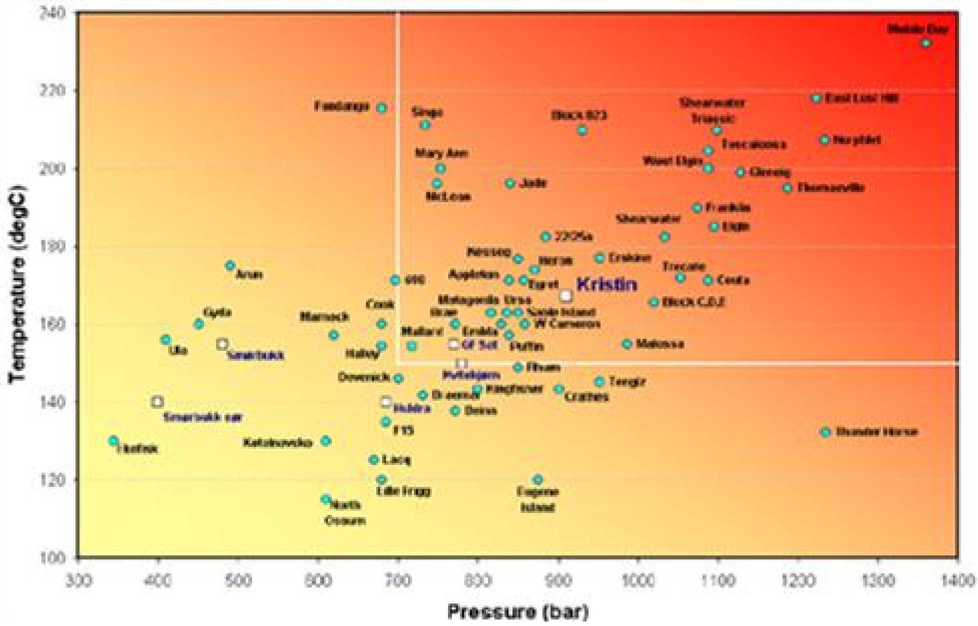
Deepwater flow assurance should always be considered from an integrated standpoint, taking into account the well, reservoir, and production systems to make sure the full range of fluid scenarios and compositions are examined, and to avoid costly resampling and re-evaluation after systems are built. Production fluids interact with the reservoir, well, pipeline, surface facilities, and the environment. All these impact flow assurance, leading to potential issues with hydrates, wax, asphaltenes, scales, slugging, emulsion, foam, sand, and corrosion. Deepwater flow assurance requires a full understanding of these interactions and a multi-disciplinary approach to managing them. Modern simulation software allows such an approach to be integrated efficiently into asset team workflows.

Inevitably, it will be necessary at some point to shut down and restart a system, whether for repair, maintenance, or for extreme weather. A well-designed start-up procedure, informed by precise simulation, is therefore important to limit the need for well interventions. Deepwater well intervention is particularly difficult. Even on land re-entering wells is expensive and time consuming. Intervention expense, risk, and complexity are amplified in deep water.

Fluid Pressure and Temperature

When pressures and temperatures exceed 10,000 psi (~700 bar) and 300°F (~150°C), the development is considered High Pressure High Temperature (HPHT) and costs tend to increase substantially. The "HPHT frontier" has been pushed by multiple projects so that many proven options are now available well above 10,000 psi & 300°F. In 2001, FMC were selected by BP to develop the first 15,000 psi (~1030 bar) Enhanced Vertical Subsea Tree that could withstand up to 350°F (~177°C) for its Thunderhorse project in the GoM. Statoil set the northern seas record for HPHT tiebacks and flexible risers with the Kristin gas condensate field development which started production in 2005 The graphic below dates from 2011.

Figure B-6 The HPHT Frontier
(source: Statoil)

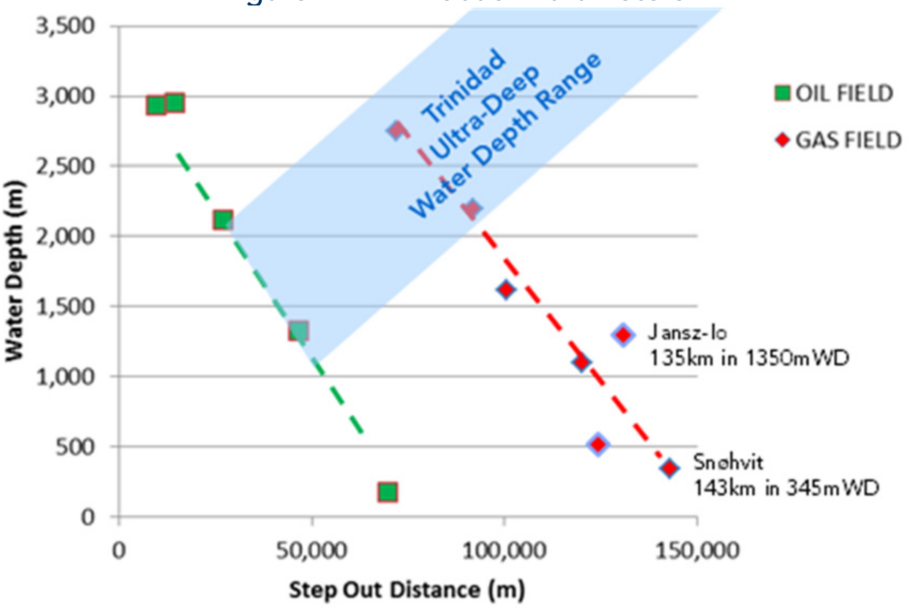


To date, no HPHT reservoirs have been encountered in T&T.

Tieback Distance

The distance between a subsea well cluster and the host facility which must be covered by the tieback is a key determinant to the viability of the tieback development concept. Recent well-cluster and template tieback developments have greatly extended the industry's perception of what may be a "practical" tieback distance, as illustrated in the graphic below. This suggests that a tieback distance of 120 km in the 1000-2000 m water depths incurred in the recently released acreage to the east of Trinidad could be achievable. However, distances beyond 80 km must truly yet be considered as "frontier" with either very specific reservoir and/or produced fluids characteristics or dependence on still immature pressure-boosting technologies required to extend tiebacks to 120 km or beyond.

Figure B-7 Tieback Parameters



The table of frontier tiebacks above provides specific examples of the distance and water depth combinations achieved to date by subsea tiebacks in production and currently under development.

The impact of these industry tieback metrics on the T&T deepwater acreage is illustrated in the map below where concentric circles at 40 km, 80 km and 12 0km, representing increasing levels of tieback complexity are superimposed on the map of T&T deepwater acreage, centred on the existing infrastructure at the Dolphin, Angostura and Toucan fields.

While this is a fairly simplistic delineation of current industry capability to install subsea tiebacks, it clearly demonstrates that much of the deepwater acreage taken up under recent PSCs, and most of the deepwater acreage offered in recent rounds, falls outside current industry experience of subsea tiebacks. This implies that new offshore structures will be required to support gas production from the eastern half of deepwater acreage, adding to the cost of development in this area.

Table B-1 Frontier Province Tiebacks

(source: Petroleum Economist)

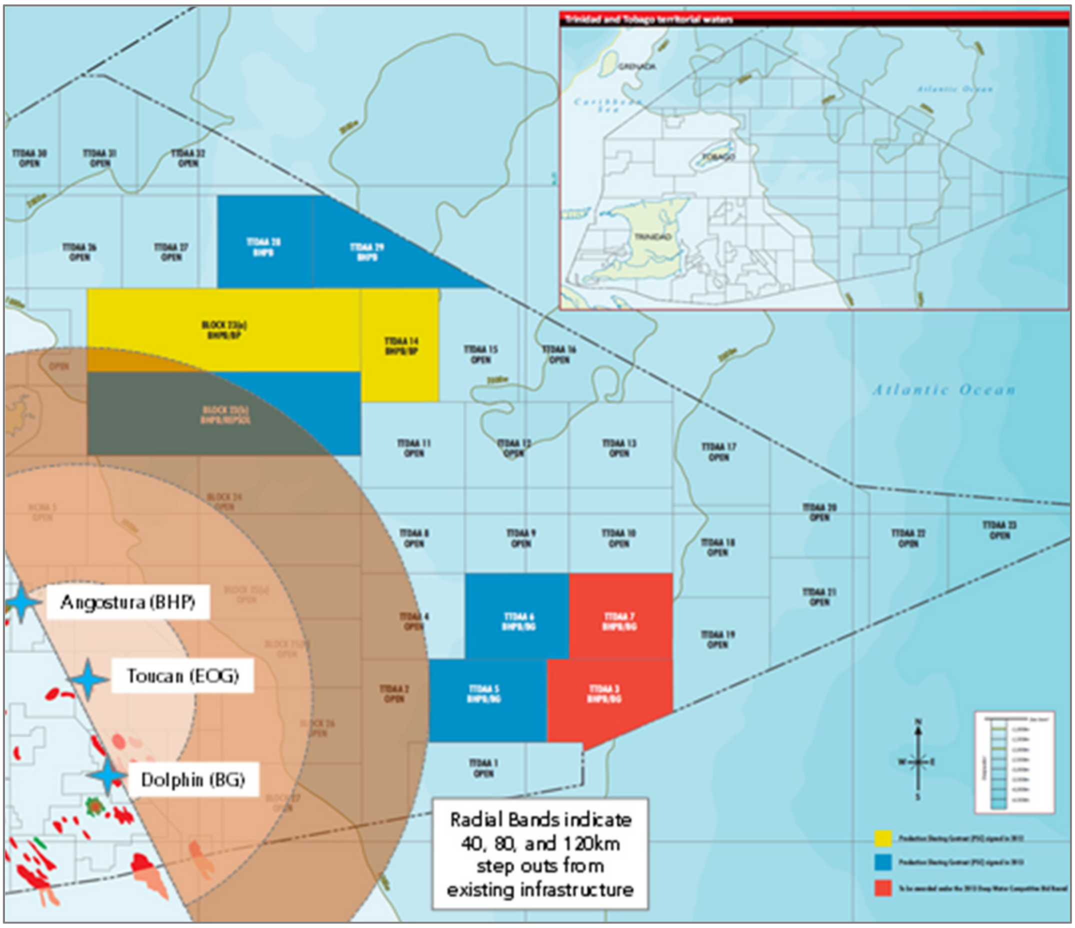
Field Name / Operator / Location (& key Production Characteristics)	Peak Rate	Step Out (km)	WD (m)	Subsea System Features
Tobago / Shell / US GoM (oil with associated gas)	100 Mboe/d combined	10	2 934	Great White, Silvertip, and Tobago produce through a 135ft tall caisson separation and boosting system
Mica / XOM / US GoM (oil with associated gas)	145 MMcf/d	47	1 326	Single producing well record in US GOM
Cheyenne / Anadarko / US GoM (lean non-associated gas)	70 MMcf/d	72	2 748	
Canyon Express / Total / US GoM (lean non-associated gas)	86 Mboe/d	92	2 198	
Mensa / Shell / US GoM (very lean non-associated gas)	52 Mboe/d	100	1 615	
Ormen Lange / Statoil / Norway (very lean non-associated gas)	50 000	120	860	
Snøhvit / Statoil / Norway (Arctic) (very lean non-associated gas)	ca. 0.62 Bcf/d (4.MMt/y LNG)	143	345	Subsea production to gas processing and LNG production facility on an island
Under Development				
Laggan-Tormore / Total (non-associated gas)	500 MMcf/d	125	500	
Jansz-Io / ExxonMobil (w/ CVX) (lean, sweet non-associated gas)	ca. 1 Bcf/d	135	1350	Large floating compression facility expected in future

Water Depth

Pipe laying and equipment installation capabilities of the industry are well-proven beyond 2000 m WD. Exploration and potential field development projects in T&T waters will be unlikely to pose any real challenges to existing field installation or pipe laying service companies for many years.

Figure B-8 Trinidad and Tobago Deepwater Area for Development

(source: Petroleum Economist)



Geotechnical Issues

Unfavourable seabed bathymetry can lead to pipe laying challenges such as long unsupported spans (esp. at escarpments or canyon crossings). Soils instability and surficial geology can also have a significant impact on the installation of deepwater pipelines. Seismic activity in the region is high; so, seabed stability may be a local issue requiring detailed bathymetric and soils mapping at fields and along potential pipeline routes. There is evidence of shallow gas flows (caused by wells penetrating hydrate formations near the seabed) and mud volcanos in the deep waters of the Eastern Maritime province (ref. SPE-153619-MS by MEEA 2012).

Combinations of hydrate formations and seismic activities lead to what could be seafloor stability hazards on a grand scale (e.g., the famous mega-scale Grand Banks landslide of 1929 and the Storegga subsea avalanche off Norway around 8,000 years ago). In SPE-153619-MS, J Rajnauth states that warnings to operators on the importance of careful site surveys seem well justified. Fortunately, industry now has decades of experience with well-proven practices and mitigating measures to avoid or limit the impact of these hazards so that exploration, development, and production ventures can be advanced on T&T's deepwater frontier with confidence.

Metocean Impact

Hurricanes and the deep marine currents off the eastern shelf of T&T are all well documented. While presenting some challenges to drilling and field installation activities, they are manageable and have little impact on the operation of subsea field developments considered in this section.

Flow Stream Hydrate Management

Deep waters have cold seabeds (~0°C). At elevated pressure (>70 bar), in even moderately low temperatures (circa 15°C) and when water is present in the fluid stream, a solid formation between water and methane molecules of hydrate “ice” can accumulate and block flow lines. Water is present in sufficient quantities for the formation of hydrates in all gas well streams.

There are two approaches to preventing the formation of hydrates: maintain the fluid temperature and pressure outside the hydrate formation zone or add chemicals to the fluid which inhibit hydrate formation:

- Insulation of flowlines retains heat in the produced fluids and can keep flowing wellstreams out of hydrate conditions for extended distances. However, if production shuts in, the flowline will begin to cool and pressure must be reduced in the flowline by blowing down its contents to avoid hydrate formation.
- Continuous injection of chemicals such as glycol can inhibit the formation of hydrates at ambient seabed temperatures. Glycol is generally injected into the wellstream at the wellhead or downhole, supplied in a small diameter line piggy-backed on the export flowline. When the wellstream reaches shore or the host platform the water glycol mixture is separated from the gas flow and glycol recovered in a distillation process.

For subsea tiebacks, key issues determining the selection of approach to hydrate control include:

- Distance: as distance increases the use of insulation will require sustained high flowrates which may not be maintained in later field life.
- Slugging: gas with low liquid loading allows flowline and host platform facility design without the need to consider liquid slugging. Injection of glycol will eliminate this advantage.
- Host platform capacity: regeneration of large volumes of glycol requires large and heavy equipment which must be accommodated on the host platform.

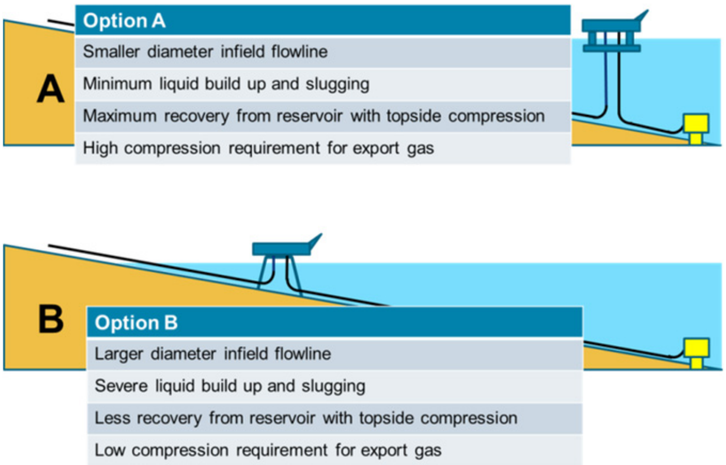
B.2.2.4 Installation of a Host Platform

The assessment of development concepts for a field through a subsea tieback will generally be performed in comparison with development options involving installation of a new host platform or floating facility. The decision between a subsea tieback to an existing facility and installation of a new facility will be driven by technical feasibility and project lifecycle economics. This section considers development issues which often have most impact on this analysis and decision.

Comparing a few of the massive gas developments in the deep waters off the Northwest Shelf (NWS) of Australia illustrates the range of solutions selected by project teams. The Gorgon/Io-Jansz complex is under development through the world’s longest subsea tiebacks (circa 135 km for Io Jansz) to supply gas to the Barrow Island LNG plant. Although water depths are moderate (200 m) out to the Gorgon field (65 km from Barrow Island) potentially enabling installation of a fixed structure, the project was able to install a purely subsea system for the initial production phases, assisted by the low liquid loading of the more remote Jansz field in particular, reducing slugging and flow assurance issues despite the use of glycol injection to inhibit hydrates. Platforms are planned at both Gorgon and Jansz fields for late life compression unless subsea boosting technology develops sufficiently in the intervening period. Pluto's short (11 km) gas tieback to a shallow water riser has allowed a reduction in the pressure rating of the 180 km trunkline to shore. The moderate liquids content did not create serious flow problems and could not justify the cost of a floating FPSO facility in the field. In the future, an additional compression platform (adjacent to the existing riser platform in 175 m WD) is planned to complete field depletion. Ichthys is being developed with the world's largest semisubmersible FPS which directs gas and liquids from the flowstream to an adjacent dedicated FPSO so those liquids can be processed, stored, and exported by tanker while sending a "LNG-ready" stream of gas east almost 900 km to a LNG production plant.

Where a platform is required to support remote gas developments, the advantages of locating the structure close to the producing field must be compared with the cost of installing a facility in water depths such as those encountered in the T&T deepwater acreage.

Figure B-9 Platform Development – Proximity vs Water Depth



Development A and B are both producing gas from the subsea tree(s) back to shore. Development A utilises a floating platform in deep water ~1 km offset from the subsea trees of the field. Development B utilises a lower cost shallow water fixed platform about 60-80 km from the subsea trees.

For development A, the flowline and riser from the well to the platform are short and pressure losses will be small. Therefore a smaller diameter infield flowline and riser can be utilised. By contrast, in development B, pressure losses from the well to the platform are significant and the flowline and riser will have to be larger diameter. When not producing at full capacity, velocities in the larger diameter flowline in case B will be lower than case A and liquid drop out will be greater. Liquid accumulation will therefore occur more rapidly in case B flowline. The higher liquid accumulation combined with the longer length of the flowline combine to cause more severe slugging. This increased liquid "hold up" demands a larger slug catcher be placed on the fixed platform than on the floater.

Assuming a MEG injection hydrate management approach for the wet gas, the volume of MEG present in the flowline system will potentially be far greater in case B than case A due to the longer flowline and potential for liquid hold up in the line. Therefore the topside facilities on the fixed platform in case B will need to have much greater MEG storage capability than the floater in case A.

In late field life, the well flowing pressure will decrease, reducing flow from the wells. To decrease the back pressure from the well, compression can be added to the topside to reduce the arrival pressure at the topside. This will provide more benefit with the case A deepwater platform development providing the lowest back pressure at the well due to the small pressure drop in the flowline and allowing the greatest recovery from the reservoir. In comparison, the same inlet compression on the case B shallow water platform will not provide as much benefit at the well due to the higher pressure drop through the flowline system. Conversely, greater compression will be required on the export gas for option A than option B due to the longer export pipeline length.

Extensive flow assurance investigations are required from very early in the project maturation process to understand which approach may be best suited to each significant discovery. The typical sequence of analysis performed would be:

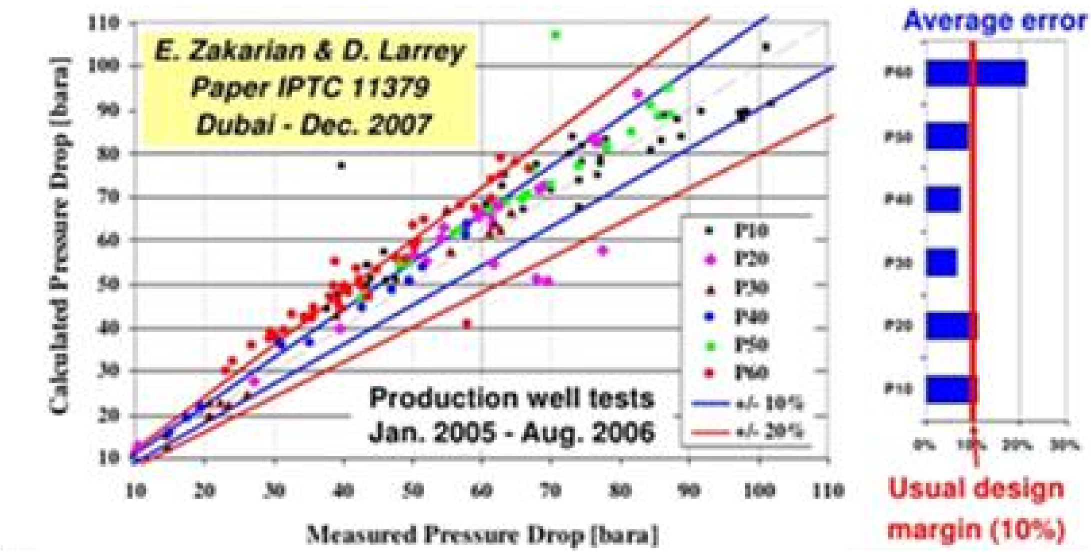
- Perform fluid characterisation
- Steady state production flow analysis
- Identify a hydrate management strategy
- Perform transient analysis for system

These analyses need to be performed for different stages in the production cycle from early conditions with high flowing wellhead pressures, to late field life conditions of low flowing wellhead pressures and increased water cut.

The accuracy of analytical models/tools is a key issue in the addressing flow assurance concerns (like hydrate management). Even though industry has spent many 10's of millions of dollars on researching the topic, a large design contingency factor must be carried due to the inaccuracies that remain – even in the highly respected software tool, OLGA® (see Figure B-10 below). As a result, except for situations/reservoirs providing very dry, sweet gas, there can a substantial penalty to pay for pushing very far downstream the point at which the produced fluids are processed and the problems are (in theory) eliminated.

Figure B-10 Measured Pressure Drop vs. OLGA®

From the closest subsea manifold to the topside production choke inlet



B.3 NEW DEEPWATER TECHNOLOGIES

The "new" deepwater technologies are in many cases not so much new as just "not fully mature". Some of these have existed as ideas for several decades but are just now, finally seeing the first applications in production, while others are still in trial or pilot stages of evolution. This section only reports on "new" technologies that have at least entered pilot or first full deployment stages. "Pilots" in deepwater technologies relate to quite a range of budget allocations from less than $100 million for a seabed pumping or compression skid "pilot production" project to more than $10 billion for Shell's Prelude FLNG. While Shell has hopes for building many sisters to the Prelude FLNG barge, in some ways this application reflects a pilot test for many unproven technology aspects.

For a forward-looking assessment of technologies on the horizon which may impact T&T's deepwater hydrocarbon resource exploitation efforts, we can recommend a review of the "Technology Radar" survey/study by LR Energy in 2014. The results are highlighted in Upstream Technology magazine Issue 5/2014 which notes that over 50% of the >250 survey respondents considered remote subsea automation and operation to have significant near-term impact.

This discussion/listing of relevant deepwater technologies starts from the general, then progresses from the bottom up and across the realm of offshore hydrocarbon resource exploitation. It is important to realise that while platforms may appear to be the biggest component of deepwater field developments, they are discussed where they fit in the value chain. In many cases, the choice of platform type is not the most important aspect and may, in fact, may be just a matter of a particular operator's past experience or bias. Note that since Poten's scope is primarily focused on "development technologies", subsurface/geoscience aspects are only lightly touched in the following even though they form the foundation of value for the whole enterprise.

Once the technologies are listed and discussed, they will be tabled to summarise the impact they would have on HC recovery, well count, and production flexibility.

B.3.1 General

B.3.1.1 Decision Making

Quality Decision Making (QDM) methods have been proven to be advantageous in the most complex decisions that involve many players and perspectives. It is worth noting that achieving and implementing higher quality decisions does not have to be as complex an undertaking as suggested by the recent cover of the Harvard Business Review (shown below).

Most world-class IOCs have now adopted QDM practices involving methods taught by leading business schools such as – Decision & Risk Analysis (D&RA) out of Stanford or the Analytical Hierarchy Process (AHP) developed by Prof Saaty of the University of Pittsburgh. Business and academic literature has for decades now documented the ability of companies across many industries to achieve sustainable success through the conscientious adoption and implementation of these (or similar) disciplined approaches to complex strategic planning and business decisions.

The MEEA can adopt some flexible decision and portfolio management models that will assist in establishing rational exploitation of the country's natural resources within the Master Plan. MEEA might also inspire operators to employ QDM best practices as a means to ensure that operators' major project investment decisions fully align with the Master Plan by requiring documentation and presentations that transparently demonstrate alignment. Performance ("availability") predictions using stochastic, event domain simulations for modelling and analysis results improve and yield valuable insights throughout the life of the venture.

Figure B-11 Harvard Business Review – How to Make Smarter Decisions

The leading IOCs in the oil & gas industry have embraced advanced QDM practices in so many facets of their enterprises that the SPE and API are now cooperating through the creation of a taskforce charged with writing a Recommended Practice for quality decision making. This new guide is primarily focused on how to properly perform D&RA studies in support of critical decision making but will also recognise the value and use of alternative methods and tools that are widely adopted and proven to yield benefits.

D&RA is often used by the IOCs to determine whether "another" appraisal well or the acquisition of "more seismic" can be justified. The D&RA methodology most suited for this is called "Value of Information" (VOI). Woodside has published that "VOI analyses are… increasingly as an essential part of data acquisition and data analysis. As a result, sizeable reductions in well-data-acquisition costs have been achieved and data acquisition and analysis has become more focused" (Koninx, 2001, SPE-69839).

Today, dynamic simulations can be performed for even the most complex systems to a degree that exposes the weak points or bottlenecks so planners and operators can find the means to greatly improve performance before the biggest investments are made and during field life to ensure and improve efficient operations. IOC operators have successfully used and depended on the results from dynamic simulation (ref. Shilling et al OTC-12952-MS and OTC-18122-MS) to guide drilling program operations in challenging environments. Australian operators have used dynamic simulation to assess the likelihood of success for the largest developments by modelling systems from offshore gas production through to delivery at their customers' distant ports. A recent study by Poten has revealed to one IOC that their LNG fleet operations can be optimised in a way that will yield a savings of ~$0.5bn for one project.

Portfolio optimisation is also practiced widely using a number of tools, quite frequently AHP. The leading AHP software is used by BP, Chevron, ExxonMobil, and Shell (ref. Expert Choice website). The tools and templates have evolved rapidly in the past two decades such that most major firms managing multiple complex investment portfolios depend heavily on the results from their portfolio analysts.

Figure B-12 The Basic Form of Decision Structuring in the AHP

(Source: R Vargas, PMI Global Congress 2010)

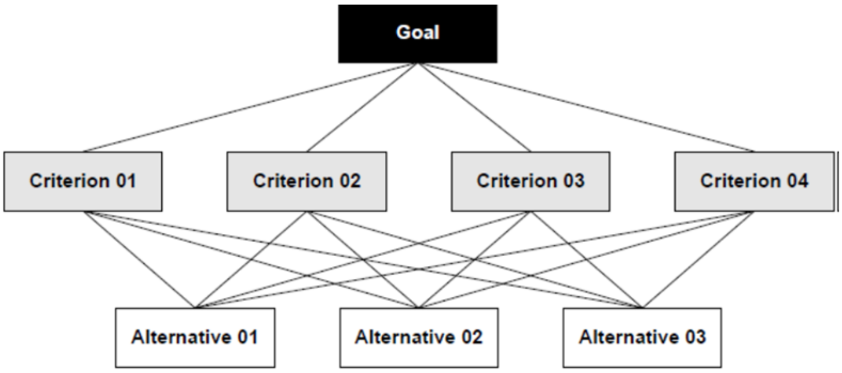


Figure B-13 An AHP Model for Portfolio Optimisation

(Source: R Vargas, PMI Global Congress 2010)

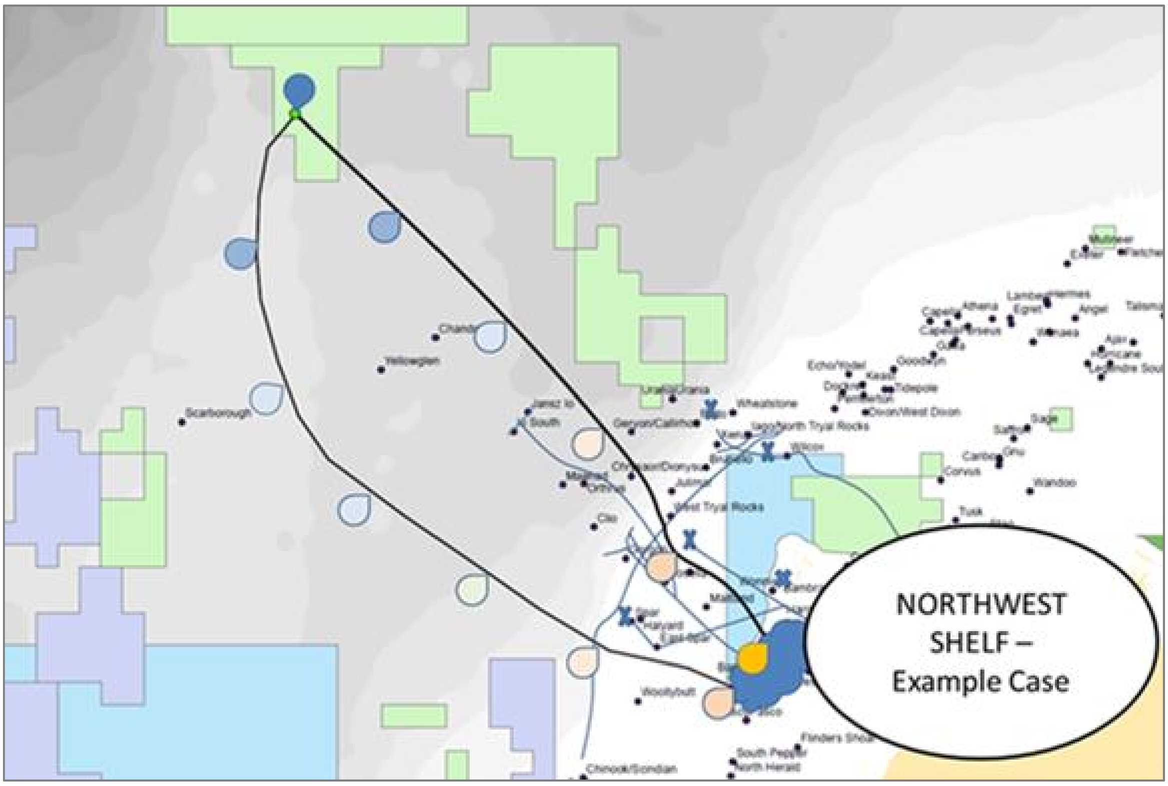
AHP is a methodology that arises from operations research literature that is used as a non-parametric method for making complex, often qualitative decisions in a robust, consistent fashion. AHP has now been adapted as a tool in the selection of (and the allocation of capital to) investment opportunities. When looking into how organisations select projects to execute, there is a constant desire to have clear, objective and mathematical criteria. However, decision making is, in its totality, a cognitive and mental process based on tangible and intangible criteria (Saaty, 2009, Principia Mathematica Decernendi), which are arbitrarily chosen by those who make the decisions. When opportunities in T&T are being evaluated by the operators, they must compete with opportunities around the globe to win investment dollars.

B.3.1.2 Information Technologies and Data Management

Advanced and pervasive data gathering, management, and mining techniques (the "cloud" evolves to the living "fog" and limited A.I.) have evolved rapidly in recent years. For example, geomatics and Geophysical Information Systems (GIS) mapping have supported improved site or route selection (ref. White et al, OTC-24789-MS). This hybrid technology combines the power of the AHP with advanced data management of GIS to allow engineers to keep in proper perspective all critical decision parameters about where to place a well cluster or platform or route a pipeline (or new highway). The technology is often called "spatial AHP" or "advanced MCA". The weighted decision criteria are applied to the "layers" of information in a relevant GIS database. Chevron used spatial AHP for Wheatstone LNG site selection. Figure B-14 shows how spatial AHP can be applied in selection of a pipeline route offshore Western Australia. Each pipeline route is being "scored" against "penalty criteria" along each unit of length from start to end. Colour coding can be used to alert the pipeline engineer that a route is becoming too severely penalised as, for example, it passes near protected reefs or platform anchor spreads. Advanced MCA is as much about the transparent and rigorous process of site or route selection as it is about the final recommendation – this approach has earned a high level of respect and confidence with regulatory agencies as well as the engineers who apply it.

Figure B-14 Application of "Spatial AHP" in Pipeline Route Selection

(source: White et al, WorleyParsons)

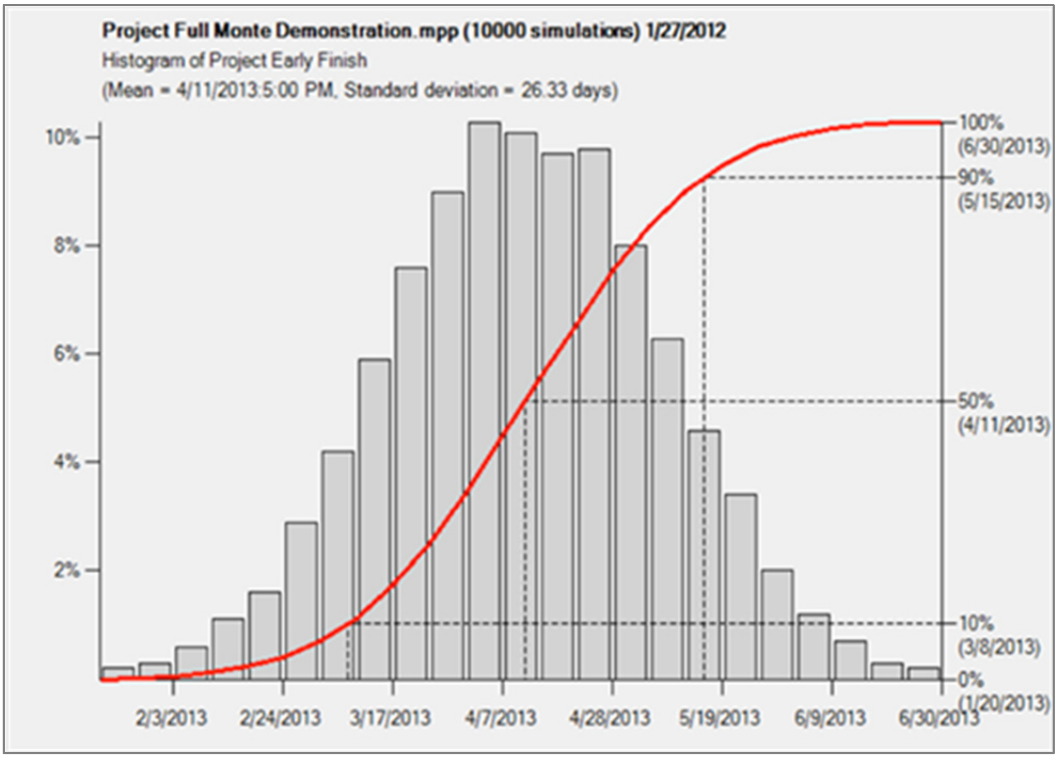


B.3.1.3 Project Management

Probabilistic methods to model and manage project uncertainties and risks are now well established and used by most major international firms (IOCs and contractors). Cross-over practices from other industries (e.g., "Scrum" PM from the IT industry) have supported continued evolution in this area.

Effective input to probabilistic project management tools requires the involvement of experienced project managers with insights on ranges of uncertainties on and forms of dependency between specific tasks. When project plans are well developed and properly modelled, it is possible for operators to improve their good understanding of the range of project outcomes (see Figure B-15). When the impact of project risks are appreciated, effective mitigation measures can be employed.

Figure B-15 Modern Software Presents the Cumulative Effects of Project Uncertainties
(Source: Tensix.com)



The most competitive vendors on the high-tech edge of deepwater hydrocarbon exploitation have realised that their competitive advantages are fleeting. Their success-to-obsolescence timeline is similar to that in the computer and telecoms industries. Therefore, companies like Schlumberger have been forced to adopt highly agile project management practices, including the "scrum" methods so common in hi-tech firms. The offshore industry is already benefitting from reduced product development and introduction timelines. T&T will benefit as even more firms learn from and adopt agile project management techniques.

B.3.1.4 Materials, Coatings, Manufacturing, and Welding

Great advances in materials technologies (especially metallurgy/welding, ceramics, long-chain polymers, and composites) as well as manufacturing methods (e.g. nanotechnology and 3D printing) and quality assurance all continue to improve the means for ultra-deepwater hydrocarbon exploitation. High strength mooring wires and ropes have made permanent installation of floating platforms in ultra-deep waters possible.

Steel and steel alloys have become highly adaptive materials. Improved welding technologies minimise the degradation of properties of welded joints that can be verified in almost real time by using Acoustic Emissions (AE) monitoring for inspection during fabrication and testing. New alloys that expand service capabilities are being qualified for industry use at a rate that challenges welding engineers to keep up.

Of all the inspection technologies that have evolved with the industry's push into ultra-deep waters, the highly automated capabilities of AE technology have gained acceptance in providing the means to proactively identify cracks in structures (usually at welds) long before they become dangerous problems. The use of AE inspection during manufacturing or fabrication allows the vendor to establish a baseline "acoustic signature" that serves for initial approvals and provides a foundation for interpretation of future structural decay. Passive AE monitors permanently assembled on structures can track the growth of cracks and even "hear" corrosion processes.

The challenges of welding titanium structures have been mastered such that titanium is in wider use in spite of its cost. The strength, flexibility, and durability of a titanium product (like riser stress joints) make it worth their high cost. At the same time, a new iron-aluminium alloy has been discovered that may completely disrupt the titanium market (ref. The Economist, Feb 2015).

Although the industry still typically depends on cathodic protection for ensuring long service lives of structures in marine (saltwater) environments, coatings and how they are bonded to the surfaces they are intended to protect continue to make inroads. Both ceramic and polymer coatings offer protection for periods that make it harder to justify the weight and cost of anodes on structures that are intended for installation in deep waters. The weight and complexity of welded anode cathodic protection systems put high burdens on installation equipment and crews. In many cases, the coating systems are employed together with anodes to limit the extent (weight and cost) of cathodic protection systems. This is especially critical in projects where weight and longevity are critical – the deeply submerged BSR buoys for Petrobras that are intended to serve without maintenance for 25 years.

In addition to facilitating rapid prototyping for hi-tech manufacturing, 3D printing is now frequently used for design of complex structures to ensure that proper operating clearances are achieved. Subsea7 has employed the technology early in the design process for multi-function subsea manifolds. There are many examples where 3D computer models have not adequately alerted designers to potential clashes. Physical 3D models overcome some of these to avoid costly mistakes on complex assemblies that are intended to be installed where human or ROV/robotic interventions are costly if not impossible.

Figure B-16 New Technology Creates Vital Machine Parts Using a Laser Beam
(Source: Shell website)

B.3.1.5 Integrity Monitoring and Management

Predictive or adaptive versus prescriptive or reactive maintenance planning means that equipment is maintained on a schedule driven by actual wear and tear but before a failure occurs. Advanced monitoring methods allow the predictive models to be adjusted based on actual performance and/or measured degradation so that components are changed out when/as needed. Unnecessary production interruptions are avoided. AE monitoring is one of the inspection technologies that provide effective insight into the integrity/condition of structures, pressure vessels, and mechanical systems. GE has developed a submerged acoustic monitoring system that has been tracking the vibration of subsea compression facilities off Norway and has proven its ability to help operators anticipate an unacceptable state of degradation.

B.3.1.6 Safety and Risk Management/Analysis

Rational and rigorous safety management procedures have been adopted industry wide such that the rate of lost time and pollution causing incidents has been greatly reduced over the past two decades. While the Macondo disaster made headlines with major human and financial losses, both the likelihood and consequences of serious hazards are lessened through better anticipation of such events and industry's ability to analyse what could happen (e.g., ignition, fire, and explosion modelling with Computational Fluid Dynamics (CFD)). To some degree, many of the improvements in effect today are due to the horrible losses caused by the loss of well control at Macondo.

B.3.2 Subsurface (Geosciences and Reservoir Engineering)

B.3.2.1 Seismic Data Acquisition and Processing

Seismic data and analysis is a foundation stone of hydrocarbon exploration. Historically, seismic data have been used to interpret structures and potential hydrocarbon traps for exploration drilling. Today, geophysical data are being used to yield better understanding of rock properties ahead of the bit and to geosteer the drill path based on favourable rock property information, as well as formation structure.

Seismic data acquisition and processing techniques are being developed to support increasingly complex subsurface developments including deepwater subsalt environments, horizontal resource plays and enhanced oil recovery projects onshore. Technological development includes advances in broadband data recording, simultaneous sources, full-azimuth 3D, higher channel counts, wireless systems, smaller and more self-sufficient receivers, and robotic autonomous nodes. However, the overarching trend common to virtually every seismic survey is the need to acquire more and more data–more angles, more density, more channels, more frequencies etc., with ever-greater efficiency and accuracy.

In deep water, the objective is to maximise prospect knowledge and reduce technical and economic variables. Deeper waters are often accompanied by deeper prospects, often hidden below complex and seismically opaque geological structures. Innovative acquisition techniques and new workflows enable geophysicists to better characterise the uncertainty based on better images of the subsurface.

B.3.2.2 Recording Fuller Spectrum Seismic Signals

Significant research and development in seismic acquisition is taking place with both broadband and simultaneous-source methods. Broadband seismic attempts to capture the full spectrum of both high and low frequencies for improved-resolution imaging and data inversion, enabling a better understanding of rock properties in the subsurface. Recording the full range of frequencies provides higher-fidelity data for clearer images with significantly more detail of deep targets as well as shallow features. The additional frequencies in the data allow a higher-fidelity inversion of seismic back to the underlying rock properties, and improved confidence in the ability to predict and match well data. Seismic ties to well data are improved, and broadband data better correlates to geology. The result is more quantitative interpretation and higher confidence in rock properties away from drilled well locations.

B.3.2.3 Acquisition Strategies to Tackle Ghosting on Offshore Acquisition

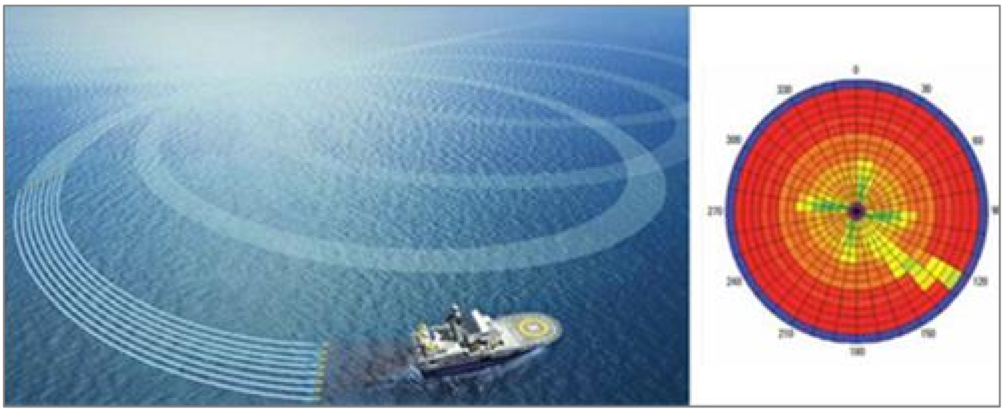
When a source is activated in the water, not all the energy goes down. The fraction that goes up hits the surface and then is reflected downward so that it interferes either constructively or destructively as it travels down. Often referred to as “ghosting,” this has been a limiting factor to the recorded bandwidth of seismic data in marine acquisition. To deal with ghosting offshore, surveys now include towing different types of streamers, or towing conventional streamers in different geometries. These strategies mitigate some of the problem caused by towing the streamers below the surface. Streamers that contain both pressure and velocity measurement devices have the potential to distinguish energy traveling upward from energy traveling downward, and to thereby “deghost” the recorded data. Even more complex measurement systems are being deployed, which measure not only pressure and velocity, but also record the gradients associated with the changing pressure field. Using this gradient information potentially enables 3-D reconstruction of both up-going and down-going wave fields at any location within the streamer array, and at any desired datum.

B.3.2.4 Richer Azimuths

Advances in wide-azimuth and full-azimuth (FAZ) acquisition geometries have been driven by the extreme challenges of imaging at depth in subsalt plays. FAZ data result in a better image for interpretation, and also can improve the understanding of fracture patterns, and reveal dips and geologic features unseen in limited-azimuth data. Having many directions of analysis can help if the subsurface structure is complicated. While the most powerful benefit of FAZ seismic is in imaging highly complex geologic features, such as salt bodies and the sediments beneath them, high-fold, FAZ datasets also are being acquired in shale plays to recover in situ angle-domain reflectivity at depth for fracture/stress and geo-mechanical property analysis, such as determining natural fracture intensity and orientation.

A technique used to secure FAZ data offshore is coiled shooting, which was first tested in 2007. The seismic vessel sails in overlapping circles, corkscrew fashion, recording continuously, as shown in Figure B-17 below. The offset versus azimuth plot indicates that the configuration acquires complete azimuthal and high offset coverage. This technique has been used in several regions and has given superior results in areas of complex geology such as Brazil, Angola and the GoM.

Figure B-17 Coiled Shooting - The Physical Gas Value Chain
(Source: WesternGeco)



FAZ seismic data can be very expensive to acquire. In the marine environment, FAZ surveys using streamers must tow complicated paths, or use multiple vessels or shoot the survey multiple times. These techniques all imply additional cost, but the improved final image can justify the price tag by reducing drilling and development risk, especially in high-cost deepwater projects. FAZ data acquisition is about

15 years into the adoption curve, and its application has expanded from imaging structures in challenging environments (subsalt) to imaging structures where the reservoir itself (not the geologic environment surrounding it) is complicated. This is often the case with unconventional reservoirs.

B.3.2.5 Higher Channel Counts

Increasing the quantity of data recorded from each recording has been a constant goal of the industry. The greater the number of channels, the more of the seismic wave field is recorded and the more noise is cancelled out for higher densities, improved resolution, and imaging accuracy. Twenty years ago, a “high channel count” survey might have had 1,000 live channels, while today surveys have channels counts in the hundreds of thousands.

The logistics associated with deploying a 3D survey with 1 million channels is likely to accelerate the adoption of wireless technology and autonomous nodes. FAZ data and higher folds add to the complexity and likelihood that channels will not be connected with cables. Wireless systems also remove some of the constraints on survey design geometries. Data management will take on even greater importance as companies struggle to manage the massive volume of data each survey acquires. Acquiring 1 million data streams every 10 seconds creates a huge (albeit highly valuable) dataset.

B.3.2.6 Autonomous Nodes for Offshore Acquisition

For offshore seismic acquisition the decoupling the source and receiver by using nodes allows the acquisition of long offsets for any and all azimuths. Bottom-referenced systems utilising hydrophones and geophones have the capability to de-ghost the receiver for broadband data. Multiple source vessels acting independently and randomly reduce costs significantly. The downside is that the process of deploying nodes can be slow, and speed equals cost. At this point, there must be significant technical benefit to having FAZ, long-offset data to justify its acquisition; however node acquisition also enables data recording in situations where a conventional streamer survey would not be possible.

The next generation of autonomous marine nodes is likely to be independently powered and able to be positioned remotely. Development of powered underwater nodes is being undertaken, and tests have been conducted. A recent project in the GoM marked the first seismic data to be recorded using the technology. The completely self-sufficient ocean robots were commanded remotely to position and then acquire seismic data.

B.3.2.7 Seismic Processing Trends

Doubling the number of active receivers at the same time the number of sources is doubled means the number of seismic traces in each square of 3D seismic is increasing at an even faster rate. The “richness” of the acquired data, the sheer volumes of raw data, and the demand for higher-order processing algorithms such as full waveform inversion present new challenges to seismic processing. Increased computing capabilities continue to match the impact of increasing volumes of data and continue to make data processing more time and cost efficient. Two clear trends appear to be emerging in the seismic processing sector.

- First, well-understood processes such as time and depth migrations will become more accurate. Geophysicists have long known how to solve the imaging problem, but have not been able to afford it (computationally). As a result, past developments have been focused on optimising for cost, sacrificing precision. The computational requirements often make it necessary still to take shortcuts when running migration processing steps. It is unusual to run a full range of frequencies with reverse time migration because of the associated cost.

However, as computer power increases, processes will get more efficient, fewer shortcuts will be needed, and the output will make better use of the collected data.

- Second, there is a desire to extract more and different information from a larger set of data. Interpretation has become more than just about structure, because the vast quantity of acquired data can be studied in new and different ways. It has complicated the job of processing and interpretation, but ultimately leads to better performing wells and lower risk. Structure, rock properties and fracture details are all targets for interpreting the processed data.
- In some cases, new processing methodologies that are likely to give significant benefits drive changes in how data are acquired. Conversely, new acquisition techniques can drive changes in processing. In regions E&P companies have been acquiring multicomponent, shear-wave data for a number of years, but processing techniques are still evolving and often are not yet in place to extract all the information from that data. The data are waiting for processing algorithms to catch up.

B.3.2.8 Reprocessing of Data

The life cycle for extracting meaningful information from a seismic dataset is typically only four to five years. By then, processing techniques will have improved to the point where it may be appropriate to reprocess the data for re-examination. After a decade has passed, acquisition technology has moved on so much that it often is better to acquire new data that are significantly better. New data may contain 10-fold the information, or they may have better bandwidth. It does not matter how much processing has improved, if the frequencies, offsets or azimuthal distribution are not present in the raw data.

Sometimes a large dataset or a multi-client speculative survey covering a vast area may be worth reprocessing to identify targets for new acquisition programs. It can be difficult to process a very large area in a way that highlights detail in a small part of the survey. The best approach may be to use the large processed volume to get an initial structural interpretation, and then hone in on the details of an area. Reprocessing the data can yield subtle features and more information about rock properties.

While seismic acquisition capabilities are advancing rapidly in many areas, the timeline for new seismic acquisition techniques and technologies from development to full adoption can be long. It is not atypical for a new idea to take 25 years before it matures into a regularly used commercial approach to exploration. To be successful in finding discoveries and optimising the value of existing assets, oil and gas companies need to track and utilise new technology early in its life. It is a long-term issue for a long-term business need. The challenge for operators is to stay informed about new technologies and constantly test the potential value in their operations.

B.3.2.9 Integration of Seismic Data with Complementary Geophysical Data

Gravity and magnetic data have long been used in the hydrocarbon exploration industry but in recent years there has been an increased interest in their use with an emphasis on an integrative approach to projects. At the reservoir scale, seismic data provides the primary information on reservoir or aquifer extent. High resolution 3D seismic survey has proven effective in reducing the risk of dry holes and in predicting drilling hazards such as faults and overpressure. Seismic stratigraphy provides information on depositional patterns and lateral facies variations. In addition, other seismic analysis tools provide methods for mapping fluids contacts, estimating lithology, and characterising reservoir fractures. Geophysical data, with detailed core, well, and reservoir performance data, can be also used for reservoir surveillance.

Seismic data can be complemented by gravity and magnetic data which can assist in interpreting basin to lease-scale structural geology and depth to basement studies at the oil and gas exploration stage. Gravity and magnetic data together with 2D seismic data provide vital information on the structure and composition of the basin basement. Major basement structures can be interpreted from the presence of consistent discontinuities and/or pattern breaks in the gravity and magnetic data. Gravity and magnetic interpretation provides an alternative check on the basement depth and thickness of the target stratigraphy. Companies have discovered that using these tools can be most effective in reducing the costs of new seismic acquisitions.

As explorers look at deeper, more remote and more costly targets to meet global energy demand, proven, low-cost techniques like gravity and magnetic are being brought in earlier in the project cycle to minimise the risk of conducting expensive seismic investigation in potentially less productive basins. Moreover, several areas scanned decades ago can be re-examined utilising higher resolution data and new techniques such as gravity gradiometry and satellite gravity. Software advances are enabling integration and interpretation of these data to levels unheard of a decade ago.

The increased use of gravity and magnetic data is also driven by stronger interest in the tectonic evolution of basins. There is greater interest in the crustal aspects, like crustal structure and depth to MOHO, than ever before. These parameters can play a big part in basin formation, sedimentation rates, petroleum systems, maturation and paleo-continental margins. Gravity and magnetic methods are ideally suited to help answer these types of questions.

B.3.2.10 Modelling and Data Mining Advances Enabled by Computing Power and Programming Breakthroughs

Reservoir engineering models can now be effectively integrated with flow assurance models to provide meaningful insights into how the produced fluids will behave from within the reservoir through to processing facilities even though practical margins must account for the engineering uncertainties. “4D” seismic can integrate geological and seismic models with reservoir engineering allowing essentially “real time” management of reservoirs by tracking and linking seismic, downhole, seabed, and surface measurements taken while producing the field. Improved understanding of reservoirs and their productive condition has improved the effectiveness of pressure maintenance as well as gas or water injection for enhanced recovery (e.g., EOR practices).

B.3.3 Drilling

MEEA’s 2012 SPE paper on deepwater drilling (SPE-153619-MS) reported that drilling challenges had prevented an exploration program from reaching its deepest targets. The wells were drilled in marginally deep blocks at circa 1000 m depth between 1999 and 2003. Although all but one reached their key objectives none reached TD due to ocean eddy currents and wellbore instability. One well had gas & liquid shows. This section will review developments in drilling technology over the last 10-15 years which will improve future drilling performance in deep water areas.

Many aspects of the drilling industry have changed to accommodate the push to very deep waters. The most apparent aspects sit at and above the surface but the changes go much deeper than that. Both exploration and production drilling capabilities and rigs have changed. Operations in truly deep waters demand the use of floating platforms to support the drilling facilities and riser systems. Although many forms of bottom-founded mobile offshore drilling units (MODUs) are still in use around the world, floaters are needed for deepwater exploration and production drilling.

In addition to barge or ship-shaped floaters, the industry has turned to the strangely shaped structures called “semisubmersibles” (also called “semisubs” or “semis”). The name came from “submersible” drilling units which were barges that had large diameter columns about 20m tall distributed in a way that provided stability while the barge base was flooded and submerged to the bottom in relatively shallow waters. The columns were tall enough to keep all the raised decks, drilling equipment, and people above the water and waves when the hull was sitting on the bottom. Drilling operations could proceed in the same way as would be performed on a fixed, permanently installed structure.

The “submersible” becomes a “semi” when it only partially submerges to remain a floating platform. Early designers noticed that certain arrangements and buoyancy distributions among the surface-penetrating columns and the submerged hull could provide the floating unit with very attractive motion characteristics. The desirable proportional relationships and depth of hull submergence (“draft”) characteristics became well understood between 1960 and 1990.

There have been relatively few changes in hydrodynamic design practices in the past two decades. In fact, while the semisubmersible drill rigs have become bigger to accommodate the huge payloads associated with remote ultra-deep water, today’s designers still tend to employ design principles that evolved 30-40 years ago. In recent years, much of the hydrodynamic work focused on non-linear modelling and analysis to understand and minimise the cost of designing to avoid waves hitting the deck structures and facilities or to minimise the effects when wave impacts might occur. There have also been some efforts to understand and minimise the effects of currents on semisubs but neither of these aspects have significantly altered their appearance.

Over recent decades, the practices of “designing for construction” have been refined to a great degree, allowing the units (particularly, the hulls) to be constructed more efficiently to offset the inflation of shipyard and fabricator building rates. The hulls and topsides are now designed to take advantage of modularisation and increased lifting capacities in the yards.

A bigger change has been in the way the units are kept on station in ultra-deep waters. Since floating drilling units were introduced, both barges (usually ship-shaped) and semisubs have typically been held in place by a radiating arrangement of mooring lines, called a “spread mooring”. The first floating drilling units were equipped with chain and drag anchor mooring systems. The mooring lines required to hold the ultra-deepwater units on station would be too big and too heavy to carry onboard. Engineers have turned to hybrid moorings where high-strength polyester or steel wire ropes are used in the upper portions and chain on the lower part running out to the anchors.

It can take many days for anchor-handling support vessels to run out all lines and fully install a rig in deep waters. To avoid having a very expensive rig waiting so many days to begin drilling, some operators have adopted the practice of pre-installing the mooring spreads. Relatively short runs of chain are taken out from the rig and connected to the pre-installed spread, saving many days mobilisation time.

Today, many of the ultra-deep drilling units avoid this costly aspect completely by using dynamic positioning (DP). Both ships and semis equipped with thruster systems and DP controls can drive to the site and start running the riser string even before they arrive. This practice may allow a DP drill rig to drill an additional well each year so DP drilling units usually command the highest rates.

The biggest change will occur when the currently envisioned generations of subsea autonomous robot drilling units crawl out across the seabed, providing surface observers no evidence of what is happening below. The practical applications of such sophisticated autobots are many years beyond the scope of the current Master Plan. While a robotically drilled well may eliminate the cost of and risk to crews, one must keep in mind the scale of these units to safely drill wells many kilometers long – even if most of the consumables are delivered by drones. Still, it is possible to conclude that a robotically drilled and completed well could cost much less than one drilled by a big surface ship or semi.

Drilling practices and systems for production wells have changed in different ways:

- Subsea wells may be drilled by mobile drilling units which often perform tasks beyond drilling and completing the well. The MODU is sometimes tasked with responsibility for running the production trees and templates or manifolds for a group of subsea wells.
- If a floating production unit, FPU or FPS, is to be situated directly above the majority of wells, it may be equipped with full drilling and completion ("D&C") capability or only completion/work-over capability. In the latter case, the subsea wells may be drilled by a MODU and completed by the FPU. The split duty approach can be applied for subsea ("wet") or "dry" tree wells.
- If the FPU has any drilling or completion capability, it possible to limit the payload dedicated to drilling operations by having much of the D&C payloads (esp. consumables, like casings and drilling muds) stored on an adjacently moored "tender" unit. This scheme is called "Tender-Assisted Drilling" (or TAD). Often when TAD is adopted, the drilling facilities on the FPU are provided as a modularised "package rig" that can be removed when the drilling program is completed or when the extreme weather season begins.

Any of these approaches may be adopted for the drilling and completion of production wells for T&T.

B.3.3.1 Improved Safety Systems and Practices

Since the Macondo disaster the world and industry have adopted many improved safety practices and introduced equipment and control systems to greatly reduce the potential for blow-outs. Wild well and spill containment methods and tools have been introduced to reduce the impact of such potentially catastrophic events. These practices are relevant for T&T particularly as the exploration focus moves into deeper water.

In a direct response to the Macondo incident, the oil and gas industry in the US assembled four Joint Industry Task Forces (JITFs) to focus on critical areas of GOM offshore activity; Offshore Operating Procedures, Offshore Equipment, Subsea Well Control and Containment and Oil Spill Preparedness and Response. The JITFs were not involved in the review of the incident; rather they brought together industry experts to identify best practices in offshore drilling operations and oil spill response, with the definitive aim of enhancing safety and environmental protection. Some of this work is ongoing. The ultimate goal is to improve industry drilling standards to support comprehensive safe drilling operations, well containment and intervention capability, and oil spill response capability.

The Procedures JITF reviewed critical processes associated with drilling and completing deepwater wells to identify gaps between existing practices and regulations and industry best practices. The recommendations are intended to move industry standards to a higher level of safety and operational performance, and have resulted in either revision or new development of API guidelines, which are considered industry best practices for US oil and gas operations.

The Subsea JITF reviewed technologies and practices for controlling the release of oil from the source of a subsea well where there has been a loss of control. These include equipment designs, testing protocols, research and development (R&D), regulations and documentation to determine if enhancements were needed. The JITF identified five key areas of focus for GOM deep water operations:

- Well containment at the seafloor;
- Intervention and containment within the subsea well;
- Subsea collection and surface processing and storage;
- Continuing R&D; and
- Relief wells.

The Subsea JITF focused primarily on potential operational scenarios after a well blowout has occurred. Consideration was also given to containment of hydrocarbons that may leak from subsea production system equipment (e.g., subsea production well) and casing stubs at the seafloor.

B.3.3.2 Advanced Measurement-While-Drilling (MWD) Methods

Data from the drill bit and wellbore can be fed back in real time to drillers and subsurface teams to allow fast reinterpretations and provide better targeting.

Optimal reservoir recovery demands a carefully determined number of ideally positioned wells in hydrocarbon-bearing layers. The injection of water and gas also requires the drilling of dedicated wells. In addition, there are specialised wells for production and/or for injecting water from shallow formations, and depositing drill cuttings. The common denominator is the drilling of wells, as a rule, directly from the sea bottom.

Mature fields, where all surface drilling possibilities are exhausted, require the construction of new branches stemming from the old wells. In some cases, production is maintained from the old well path, from which a multi-branch well is created. Individual reservoirs are best exploited when wells are drilled into them in a fishbone pattern. This allows the oil to flow into a common conduit up to the platform.

In some cases, the reserves are a significant distance away from the platform, which makes long-reach wells the feasible solution. Such wells have been used for many years in the North Sea and GoM. Long-reach wells have been drilled successfully at Statfjord, Gullfaks and Sleipner in the North Sea removing the need to drill additional subsea wells. Optimal directional drilling and well placement are now possible with drilling tools that steer the drill bit in all directions, while the drill string continually rotates. More and more advanced measurements are made from directly behind the drill bit during drilling, providing necessary data that permits the best possible well placement, in addition to a secure and safe drilling operation.

Measurement-While-Drilling (MWD) is a form of well logging that incorporates the measurement tools into the drill string and provides real-time information to help with steering the drill. Once a well angle exceeds 60 degrees, conventional wireline logging tools can no longer be pushed through the well to retrieve information, making them ineffective. Originally designed in the 1980s to overcome logging challenges of wells being drilled at extreme angles, MWD is a type of Logging-While-Drilling (LWD) where tools are encompassed in a single module in the steering tool of the drill string, at the end of the drilling apparatus (or the bottom hole assembly).

Providing wellbore position, drill bit information and directional data, as well as real-time drilling information, MWD uses gyroscopes, magnetometers and accelerometers to determine borehole inclination and azimuth during the actual drilling. The data is then transmitted to the surface as pulses through the mud column (mud pulse) and by electromagnetic telemetry. Decoded at the surface, the data can also be transmitted to an offsite location immediately for further analysis.

With such precise wells being drilled, MWD aids drilling engineers with real-time information so that they can make important decisions while drilling. Geosteering is a relatively new concept of positioning wells according to the geological features in the reservoir obtained through MWD. Now, video is even available to help in the process.

B.3.3.3 Extended Reach, Horizontal and "Snaking" Wellbores

Modern drilling methods and equipment have greatly improved directional and depth navigation during well construction, increasing the effective length of completions. The ability to drain massive reservoirs from a single well cluster location is realised when these well navigation features are combined with extended reach capability that now exceeds 5 miles (8 km).

Extended-reach drilling (ERD) has been around for many years, but the speed of technical developments is quickening in response to a world where the "easy oil" has already been found. ERD excels in maximising reservoir exposure in a single wellbore. There is no clear industry definition of ERD, but many consider it as drilling a well with horizontal displacement at least twice the true vertical depth, yielding deviations from vertical exceeding 60°. Wells that approach the limits previously achieved by the industry in terms of horizontal displacement and high-angle directional wells that approach the capabilities of current rigs are also described as ERD. Typically, the ERD limit is reached when one or more of the following occurs:

- The hole becomes unstable, due either to duration over which it is left open hole during drilling, geomechanical degradation, adverse pressure differential, or drilling fluid effects (or incompatibility). The onset of these conditions usually result in the sudden increase of torque and drag in the drill string as the hole begins to collapse, not related to dogleg severity (DLS) of the hole or the length of the drilled section.
- The drill string no longer travels to the bottom of the hole due to excessive drag. This differs from hole instability in that it is related to the cumulative length drilled along with the DLS of the hole, rather than the integrity and stability of with wellbore.
- When rotation is used to overcome friction and advance the drill string, such as in rotary steerable application. The limit is reached when you reach the torque capacity of the rig or the drill string.

The most frequent applications of ERD are to reach a larger reservoir area from one drilling location, keep a well in a reservoir layer for a longer distance in order to maximise its productivity and drainage capability, or drill and produce the reservoir from a remote location, to avoid hazards. With these advantages come challenges. One of the most fundamental is mechanical loads on the drill string, an area where non-traditional materials are showing promising results. Hole cleaning and managing downhole pressure are also critical, and new techniques are being developed to address these problems as well.

For some ERD applications, careful well planning and existing drilling practices are sufficient to avoid problems such as wellbore instability, lost circulation, and stuck pipe. However, results from several studies show that when well step-out ratios increase, operational practices developed while drilling conventional wells become inadequate to cost effectively deliver the wells. ERD well profile design is an integrated process that requires an optimum well path profile which satisfies two main principles of planning an extended-reach well: minimising torque and drag, and minimising well length.

Key enabling technologies for ERD are the use of rotary steerable systems (RSS), MWD and LWD tools described above. These are key enabling technologies that make ERD possible.

Exxon is one of the leaders in ERD. The first phase of Sakhalin-1 project in Russia uses a land-based drilling rig with numerous extended-reach wells and an offshore drilling and production platform. The land-based drilling rig, Yastreb ("Hawk"), is one of the most powerful in the industry, designed to withstand earthquakes and severe Arctic temperatures. Yastreb drills down and then horizontally under the sea floor a total distance of more than seven miles (11 km), making these extended-reach wells among the longest in the world.

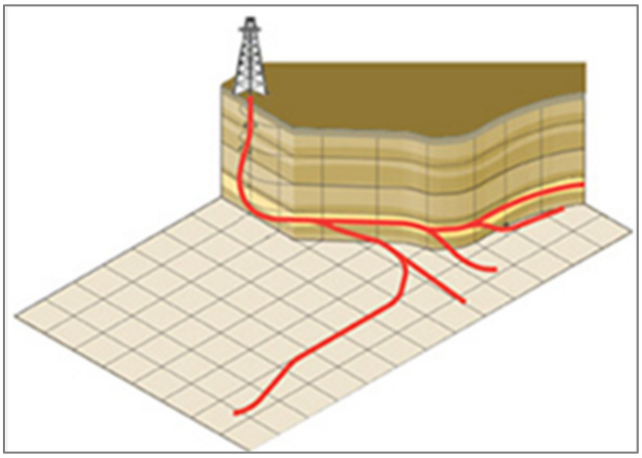
Norsk Hydro (now subsumed into Statoil) was an aggressive pioneer in using the practice of wellbore "snaking' to drill extended reach wells in the thin oil-bearing zone of the massive Troll gas field. The volumes of oil recovery per well for Troll have been exceptional. According to Statoil's website, the Troll wells are drilled down to a reservoir located around 1,320 metres below the seabed, where they are split into two to four branches. Each branch extends around 3,000-4,000 metres horizontally into the reservoir. A total of more than one million metres have been drilled in the reservoir from 180 production wells. Statoil expects to recover over 2 billion barrels of oil from a reservoir that was considered by some to be impossible to develop.

B.3.3.4 Multilateral Wellbores

A multilateral well is a single well with one or more wellbore branches radiating from the main borehole which may be an exploration well, an infill development well or a re-entry into an existing well. Multilateral configurations vary from a vertical wellbore with one sidetrack to complex horizontal, extended-reach wells with multiple lateral and sub-lateral branches. Designs can include multi-branched wells, forked wells, wells with several laterals branching from one horizontal main wellbore, wells with several laterals branching from one vertical main wellbore, wells with stacked laterals, and wells with dual-opposing laterals. However, wells can generally be divided into two basic types: vertically staggered laterals and horizontally spread laterals in fan, spine-and-rib or dual-opposing T shapes.

The recovery from a well is a function of the reservoir area to which the wellbore is exposed and in tight (low permeability) reservoirs the number of natural fractures that the wellbore encounters. A horizontal well remains in the reservoir over a longer distance increasing exposure to the reservoir and has a better chance of intersecting fractures than a vertical well, but there is a limit to how far a horizontal well can be drilled and the coverage that can be achieved in a reservoir by a single bore. By drilling horizontal laterals from a single wellbore, more extensive coverage of the reservoir by producing wellbores can be achieved at a lower cost that drilling multiple horizontal wells.

Figure B-18 Multilateral Well Profile
(Source: Wellpath Energy)



Horizontal fan wells and their related branches usually target the same reservoir interval. The goal of this type of well is to increase productions rates, improve hydrocarbon recovery and maximise production from that zone. Multiple thin formation layers can be drained by varying the inclination and vertical depth of each drainhole. This vertically staggered approach can target several different producing horizons to increase production rates and recover hydrocarbons from multiple reservoir zones by commingling production in a single main bore.

A successful multilateral well that replaces several vertical wellbores can reduce overall drilling and completions costs, increase production and provide more efficient drainage of a reservoir. Furthermore, downhole tools which allow the production from a multilateral to be varied along its length provides greater flexibility of reservoir management to increase recoverable reserves.

Production from known reserves has traditionally been expanded by drilling additional wells to increase drainage and sweep efficiency. As a consequence, both capital expenditures and operating costs have also increased with every new well. To counteract these cost increases, multilateral technology is now being employed to increase borehole contact with the reservoir, improve operating efficiency and reduce well costs. These goals are achieved primarily by drilling the main trunk and overburden from surface to the reservoir only once and by reducing surface equipment to a single installation at a significant cost-savings. Furthermore, this can be achieved in both offshore platform and subsea situations where a limited number of slots is available and in onshore locations where surface installations are expensive or where the lease has an irregular configuration.

Because of the capability to more thoroughly drain reservoirs vertically and horizontally, recoverable reserves per well and per field are increased considerably while both capital and operating costs per well and per field are minimised. Multilateral wells allow costs to be amortised over several reservoir penetrations and in some cases have eliminated the need for infill drilling. In heterogeneous reservoirs with layers, compartments or randomly oriented natural fractures, more pockets of oil and gas and can be exploited and an increased number of fractures can be intersected by drilling multilateral wells.

Once the main well architecture is in place, additional reservoir drainage can be achieved at a lower incremental cost through use of small-diameter boreholes and multiple slimhole horizontal re-entries drilled to further increase reservoir exposure. Coiled tubing is also employed to drill multiple radials from the main bore. Coiled tubing drilling is frequently used to remove near-wellbore formation damage to increase reservoir flow potential, but in the Snorre field, Norway, for example, has also been used for drilling drainholes to replace perforations.

B.3.3.5 Multilateral Re-entry

Determining the right techniques for re-entering multilateral wells to perform stimulation, acidising, perforating or any other fluid pumping operations is a key challenge confronting the oil industry today. As well configurations become more complex, the degree of difficulty increases.

B.3.3.6 Sub-salt Drilling

Industry capability to drill through salt structures has been demonstrated by the successful development of reservoirs adjacent to and beneath salt in the US GoM and offshore Brazil. Drilling through salt formations is technically challenging; it is difficult to drill quickly or directionally through salt and below the salt there is often a rubble zone and tar that is also challenging to drill. The difficulties encountered while drilling these sections are a function of salt's unique characteristics.

Salt sheets retain a relatively low density even after burial. Since other formations at the same depth and deeper increase in density over time as overburden is added, salt sheets tend to be less dense than the formations near and beneath them. If the overlying sediments offer little resistance to salt migration, as is often the case in the GoM, the salt rises. This movement generates a difficult-to-model rubble zone at the salt's base and sides. Because pore pressures, fracture gradients and the existence and extent of natural fractures are difficult to predict, well control is highly problematic when exiting the base of the salt.

Penetrating salt with a wellbore also presents a unique challenge. Under sustained constant stress, salt plastically deforms over time. This phenomenon, known as creep, allows the salt to flow into the wellbore to replace the volume removed by the drill bit. Especially at elevated temperatures, this invasion may occur quickly enough to cause the drill pipe to stick and may eventually force the operator to abandon the well or side-track around it. Shock and vibration levels inherent in the downhole drilling environment can also become acute when drilling though salt sections. This may be attributed to poor tool selection and BHA design, inappropriate drilling-fluid design, ratty or laminated salt intervals, creeping salts, and less-than-optimal input drilling parameters such as weight on bit (WOB) or rotary speed.

Among the most critical concerns when drilling into reservoirs through salt are the location and angle of the wellbore exit from the salt layer. In the GoM drilling engineers prefer to exit salt where the contact between the base of salt and underlying sediments has a low dip angle because the rubble zone tends to be more stable there than at steeply dipping flanks. When that is not possible, they strive to keep the wellbore within 30° of perpendicular to the base of salt. Attaining these drilling targets, however, is often problematic because the base of salt can be difficult to model. Since salt may be structurally complex and seismic waves travel though it at higher velocities than in surrounding layers, surface seismic surveys have historically provided only poor images below or near salt bodies. This leaves considerable margin for error in estimating pore pressure and other properties of the subsalt formation, with potentially catastrophic results, including loss of the wellbore.

In the 1990s, 3D seismic acquisition and processing greatly improved the success rate for exploratory wells on land and in shallow waters offshore but, because of complex geology, had little impact on discovery rates in deeper water. Deepwater subsalt prospects proved particularly difficult to image using data from early 3D surveys. Furthermore, even when seismic data processing provided sufficient data for successful exploration drilling though these formations, it often could not provide data of sufficient quality for efficient full field development. Improved seismic imaging techniques have improved the industry's ability to visualise subsalt formations.

Drillers are also able to more confidently exit the salt by looking ahead of the bit with borehole seismic procedures called walkaway vertical seismic profiles (VSPs) and seismic-while-drilling (SWD) techniques. Walkaway VSPs are conducted by moving the seismic source progressively farther from the wellhead at the surface. Receivers are clamped inside the wellbore just above the zone to be imaged – in this case near the base of salt – to provide SWD data that are used to look ahead of the bit and so better image the base of salt and it underlying formation. Amplitude variation with angle (AVA) inversion of the walkaway VSP is used to predict compressional (P-) and shear (S-) wave velocity ratios (vp/vs) just below the salt/formation interface. These velocities are used to predict pore pressure ahead of the bit. The walkaway VSP is then rapidly processed to provide a high-resolution image of the base of salt; it can also give details on possible sutures or inclusions in the salt. Finally, the VSP is processed to present a high-resolution image of the subsalt sediments. When the VSP is combined with surface seismic data, it is possible to attain more-comprehensive imaging of the structural and stratigraphic details in key development areas that can then be used to design well trajectories.

Familiar wireline logging technology has been adapted to LWD tools to deliver real-time time-depth and velocity information during the drilling process. This SWD system comprises an LWD tool with seismic sensors positioned near the drill bit, a seismic source at the surface and a MWD system for real-time telemetry. The time-depth data are used to position the well on the seismic map, which can be viewed the well site or remotely. Real-time waveforms allow immediate processing of the VSP, enabling a true look-ahead-while-drilling capability.

The most potent resource for dealing with drilling problems in salt continues to be expertise in quick decision making based on reliable, timely information. To that end, operators are relying on real-time drilling monitoring and on drilling support centres that use high-speed connectivity to bring together data and experts for rapid resolution of possible drilling hazards. This is partly a response to the shortage of expert personnel and the costs of the software and other tools necessary to competently drill in complex, often remote deep water and subsalt environments.

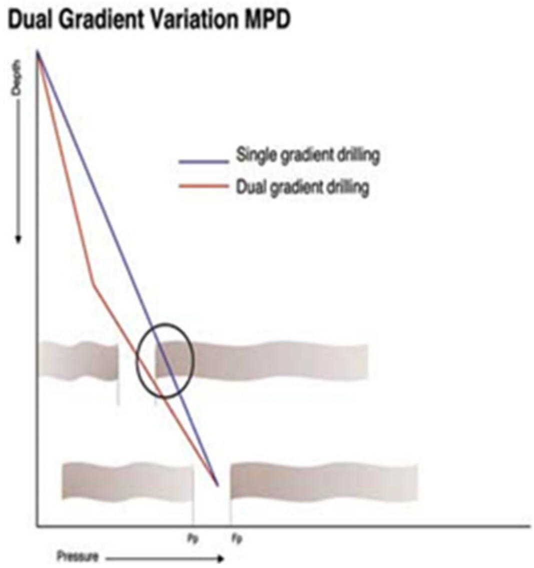
B.3.3.7 Dual Gradient Drilling

Dual gradient drilling (DGD) is particularly suitable for addressing a number of offshore drilling challenges because it enables a wellbore pressure profile to more closely match the pressures presented by nature, reducing or eliminating the impact of water depth on well design. Regarding well control, current methods of achieving dual gradient enable drilling with heavier mud weights than is possible with conventional methods. If a heavy mud is used with a single gradient system in deep water the pressure in the wellbore at the formation may exceed formation pressure. If this happens, a loss of well control could result. To reduce the likelihood of such an event, drillers tend to be conservative about when to insert and cement each casing string. Each casing string that is set takes time, costs money, and reduces the size hole that eventually reaches the reservoir. Smaller diameter completion tiebacks may undesirably limit the rate of production from a well, an effect that can also reduce the commercial value of the completed well.

DGD usually places a new piece of equipment at the seabed wellhead as compared to traditional deepwater drilling. The equipment may all be run as part of the drilling riser wellhead connection package (with the Blow-Out Preventer, BOP) as shown in Figure B-20. Alternative concepts have placed mud tanks on the seabed where drilling returns accumulate with sump pumps that lift the returns to the surface. This latter option, in theory, allows the returns to be monitored and possibly filtered for disposal at the seabed. Both options are intended to be at least as safe as conventional deepwater drilling methods and equipment but the offset returns collection tank options may provide an opportunity to isolate a potentially dangerous gas inflow “bubble” from returning directly up the drill riser.

In either case, the idea is to make it possible to have fewer casing strings and reduce well costs. Because dual gradient is created in the annulus returns path and not within the drill string, concurrent processes such as MWD and LWD are usually not affected. DGD has been promoted as a way to substantially decrease ultra-deepwater drilling time and costs for decades and now practical systems are finding application. As a result, DGD will likely be a significant factor in the commercial success of development on T&T’s ultra-deep frontier.

Figure B-19 Dual Gradient Drilling Principle and Equipment
(Source: Offshore Magazine/Courtesy Weatherford)



DGD enables navigation of narrow, shifting or relatively unknown safe mud weight windows to greater depths, simplifying well construction toward achieving total depth objective with large enough hole for well productivity.

Figure B-20 Subsea Rotating Control Device
(Source: Offshore Magazine/Courtesy Weatherford)

The figure above shows a subsea rotating control device (SRD) being shop tested in preparation of subsea mud-lift DGD application in the GoM.

B.3.3.8 Single Trip Tools

In very deep waters, it takes significant expensive rig time to run and retrieve the drill string and whatever equipment is attached to it all the way into the well. Each running/retrieving operation is a called a "trip". Unfortunately, no well can be drilled with a single trip of the drill string. Many vendors (e.g., FMC, Weatherford) have developed multi-function tools that are intended to limit the number of trips (of the drill string or casing) required during various stages of well construction and completion.

For example, FMC claims that the benefits of modular subsea wellhead design extend to its running tools. In particular, the UWD-15 systems are claimed to use fewer running and test tools than any competitive subsea drilling system. These multi-function tools provide options for running and retrieving components either individually or in combination with other components, enabling fast, accurate and reliable system installation. Another example is GE's 16" (diameter) sub-mudline equipment that allows an additional casing string to be hung at a predetermined position under the wellhead. The system is installed with a single trip running tool that installs both the casing hanger and the seal.

Every trip into and out of the wellbore adds costly hours to the already-expensive ultra-deepwater drilling programs. Therefore, operators have embraced these advances to limit costs for both exploration and production wells for their very expensive ultra-deepwater drilling campaigns.

B.3.3.9 Ultra-Deep and HPHT Wells

The industry has successfully moved the HPHT frontier well beyond 10,000 psi and 300°F (~150°C) milestone, enabling commercial well depths much greater than previously targeted in T&T waters. To date such extreme conditions have not been encountered in T&T's offshore industry, avoiding the expense and specific equipment required to deal with these conditions.

B.3.4 Well Systems and Completions

B.3.4.1 Reservoir (Recovery) Optimisation

Well completion including preparation of the reservoir formation and wellbore interface can have a huge effect on the recovery per well. Advances in drilling mud chemistry limit "skin" damage to the critical part of the reservoir at the wellbore; while completion fluids injected into the formation for fracturing ("fracking") or stimulation have greatly enhanced recovery. The equipment for fracking and ability to monitor downhole impact in "real time" are also important parts of the most recent improvements in the completion of wells.

B.3.4.2 Intelligent Completions

Completions that enable engineers to monitor and control production or injection in at least one reservoir zone are known as intelligent or smart completions. Such technology is proving to be a reliable and cost-effective tool for enhancing reservoir management. Active control of producing zones within the wellbore can protect operations from key production risks such as early water or gas breakthroughs or cross-flow between producing zones in the same well. The technology helps operators to increase production rates, extends field life, and reduces the need for well interventions.

Conventional well completions are designed to match the forecast production characteristics of the reservoir and wellbore. Once installed, there is little ability to modify production from the well other than by adjusting the wellhead back pressure at surface. If the reservoir performance forecast is inaccurate or changes over time, the completion may no longer be appropriate for the well, resulting in either reduced deliverability or shut-in of the well followed by re-entry to recomplete the well, with the associated risks and costs of that operation.

Intelligent-completion technology gives operators the ability to monitor and control individual zones within wells, reacting to changing or unexpected performance from producing zones within the reservoir. Without this control, operators may lose an entire well when a single zone unexpectedly waters out. Intelligent-completion technology is enabling operators to optimise production or injection programs, improve reservoir performance, achieve higher recovery ratios, and reduce field-development and intervention costs. The technology's reliability has been demonstrated in high-productivity wells, and fit-for-purpose intelligent completions are now being installed in wells with lower productivity to help safeguard against reservoir uncertainties and provide incremental production.

Over the last decade the use of intelligent completions has grown rapidly. The economic benefits of using this technology have been demonstrated for high-end wells globally and intelligent-completion technology is now being successfully applied to lower-productivity wells in a variety of applications. Increasingly, the technology is being used in to manage uncertainty in carbonate reservoirs, where production is primarily through natural reservoir fractures. Determining the permeability of a carbonate reservoir is challenging. In many wells, a large proportion of the fluid is produced from or injected into a relatively short high-permeability fractured section. The location of this high-permeability streak may be unidentified, even after a thorough formation evaluation and they are prone to water out rapidly and unexpectedly. The power to monitor and control production and injection in response to the uneven permeability distribution associated with carbonate reservoirs is particularly important in the Middle East where 70% of the hydrocarbon reserves are in carbonate formations. Other applications for intelligent completions include gas lift optimisation and sand management. Operators such as Statoil, Shell, and Saudi Aramco adopted intelligent-completion technology during the early stages of its development and now expect to use it in any well that is designed to produce from several zones or in which there is a risk of early gas or water breakthrough.

The benefits of intelligent completions are not restricted to carbonate reservoirs and indeed in T&T where reservoirs are generally fine-grained deltaic sandstones and siltstones, the technology has found applications. Intelligent completions were used in horizontal wells on the Mahogany field for the production of the thin oil column. The use of distributed temperature measurements eliminated the need for production logs and provided a continuous indication of the lateral length that was actually contributing to the flow. Such information allows determination of the producing well's efficiency; while also providing the justification for any stimulation job required to enhance production. In India the Oil and Natural Gas Corporation (ONGC) is drilling maximum-reservoir-contact wells and installing completions to measure reservoir conditions and provide sand control, and an intelligent completion is successfully operating in Nigeria for non-intervention sand management.

Intelligent well completions are an essential part in the Canyon Express subsea gas development of the Aconcagua, Camden Hills, and King's Peak deepwater fields in the GoM. The Canyon Express project (Aconcagua, Camden Hills, and King's Peak fields) is a multi-field development involving three distinct fields that have three different operating companies, all with different partners. The project combines all these three fields into one development. The operators initially will commingle all zones within each well. As water production starts, the ICV valves will allow zones to be shut off as necessary to eliminate water production. The intelligent completion technology provides the capability to commingle production without well intervention and to shut off zones if water encroaches. Data from the downhole pressure and temperature gauges will help maximise field potential. The data, processed on surface, will be integrated into reservoir models to obtain a better understanding of field depletion, water encroachment, and reservoir extent. This technology allows operators to obtain real-time or near-real-time reservoir data, and then reconfigure the wellbore production-injection architecture to adapt to the information obtained. During the life of the field, the technology can improve field efficiency by increasing production and minimising work-over needs.

B.3.5 Tieback Systems

Tieback systems connect the wellbore at the subsea wellhead to the inlet to the processing facilities onshore or at the surface. As noted previously, the core technologies for subsea tiebacks are now considered well proven in many forms and variations for tiebacks in deep waters and a wide range of step out distances. This section talks about specific advances in component technologies that will likely play a role on TT's ultra-deepwater frontier.

B.3.5.1 Subsea Trees

A wide range of vendors now have proven solutions for highly complex reservoir conditions and downhole completions. Reliability and maintainability have been greatly improved through standardisation practices regarding interfaces with ROV systems. Some of the important capability enhancements in recent years include the degree of monitoring and communications that can be accommodated by trees that are producing from complex, multi-bore completions and the HPHT pressure ratings noted previously. Unfortunately, tree sizes have become quite large when all the features are includes, putting some strains on the installers. However, to date ultra-deepwater installers have met the challenge safely.

The advanced metallurgy and manufacturing practices of the world's leading vendors result in products with very high initial quality and extremely long service lives. Both of these attributes are vitally important for expensive equipment that is extremely expensive to replace. Systems are also being configured so that a number of key individual components can be replaced by ROVs without retrieval or replacement of the tree assembly.

B.3.5.2 Controls

Software programs offer improved safety and stability in spite of ever greater demands for operating flexibility over great distances. Modern systems even enable essentially autonomous operation of remote in-field components or wells. However, one of the great concerns for control systems engineers is security. Since most of the information and code that enable safe, reliable operation of remote wells is now being pushed into and through the internet, essentially all systems may become exposed to a risk of unintended intervention ("hacking"). Therefore, means for isolation and security of these high value assets is continually being upgraded. Failsafe systems have always and will continue to be essential for isolating and containing reservoir pressures and fluids, and thus protecting the environment.

B.3.5.3 Umbilicals

Multi-functional umbilicals now support highly complex operations and monitoring of remote subsea facilities over very great distances. Fibre optics enable long-range communications/measurements due to the very limited energy loss of the signals being carried. The remoteness of the ultra-deep frontier licenses off T&T makes dependency on such technologies likely.

One of the important breakthroughs for umbilicals is the inclusion of high strength steel wires which allow the umbilicals to span the great ocean depths from seafloor to facilities at the surface. These reinforced umbilicals can survive the loading imposed by currents, waves, and the movements of the floaters.

Figure B-21 Complex Subsea Umbilical Cross-Section
(Source: Offshore-technology.com)

B.3.5.4 Subsea Separation, Boosting and Power Supply

As noted in preceding discussion, promising results with remote subsea tiebacks has greatly extended their applications worldwide. A big part of the future of subsea production is now expected to depend on engineered solutions for subsea gas compression or separation and boosting for oil fields. Pressure boosting has been a feature of oil and gas production since the beginnings of the industry, going all the way back to sucker-rod beam pumps and compression stations for onshore wells.

To date, there have been few commercial projects deepwater projects that depend heavily on boosting the flow stream pressure of remote subsea wells, but more are being added among operators long-range plans as challenges are being resolved and reports of success come in (see Table B-2).

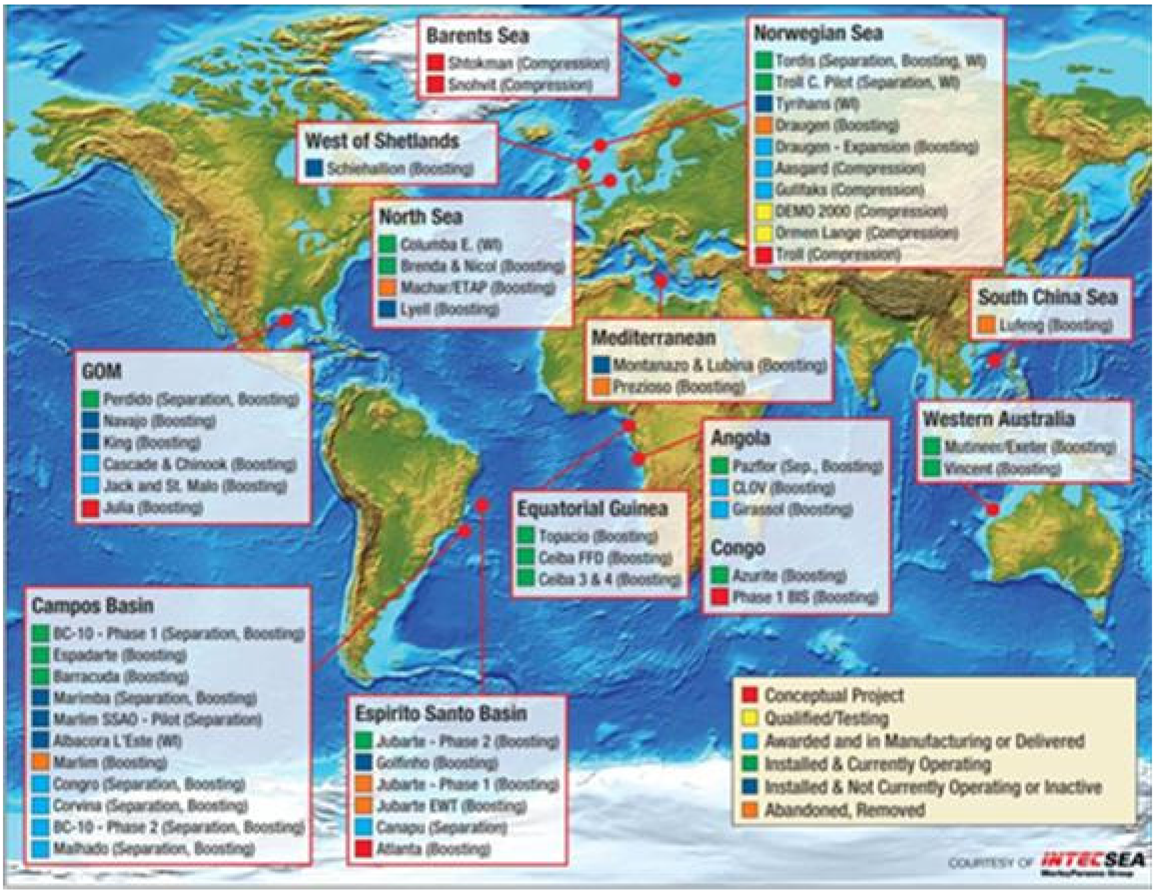
Table B-2 Subsea Processing and Compression Experience

Field Name / Operator / Location (& key Production Characteristics)	Peak Rate	Step Out (km)	WD (m)	Subsea System Features
Midgard & Mikkel (to Aasgard) / Statoil (non-associated gas)	40 000 m^3/hr (at field P&T)	40	300	2x 11.5MW compressors to reduce back pressure on reservoir from 2015
Celba / Hess / Eq. Guinea (oil with associated gas)	50 Mboe/d	14.5	750	Multi-phase pumps (MPP)
Barracuda / Petrobras / Brazil (oil with associated gas)	150 Mboe/d	10.5	1,040	MPP High Boost
Pazflor / Total / Angola (oil with associated gas)	200 Mboe/d + 150 MMcf/d	4	800	Three (3x) subsea 3-phase separation & boost units by FMC (see Figure B-22 below)

Figure B-22 Subsea Separation and Pumping System
(Source: FMC)

In general, the separation between the subsea station and the surface unit receiving the fluids is limited. For the highest production rate case, Pazflor, the boost units are quite near the base of the riser towers. Figure B-23 below shows the global distribution of subsea pressure boosting projects.

Figure B-23 Global Utilisation of Subsea Separation and Pressure Boosting
(source: INTECSEA, February 2013)



In northern waters, Shell initiated an ambitious subsea compression pilot program. However, the huge innovative project was dropped in 2014 due to rising costs and complexity, dealing a blow to a technology that some hope could revolutionise offshore production. Shell said it would postpone a project to provide subsea compression at the North Sea's Ormen Lange, the second-biggest Norwegian gas field, despite the objections of its state-owned licence partner. According to Shell, the decision will not be re-evaluated for several years, until new technology and reservoir information become available.

The success of remote compression or boosting depends on the delivery power to the equipment. Fortunately, relatively large capacity power supply can now be achieved (see Figure B-24 below). With the setback delivered by Shell in 2014, the deployment of massive power delivery projects will be delayed. However, the major vendors do continue to invest heavily in the technologies associated with providing the ability to boost flow stream pressure at points close to the reservoir.

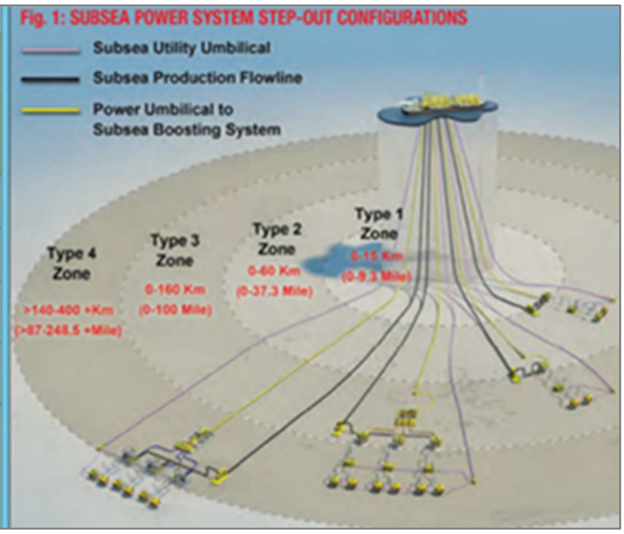
Figure B-24 Subsea Power Delivery Options

(Source: INTECSEA)

TABLE 5: POWER SYSTEM STEP-OUT CONFIGURATIONS

CATEGORY	VOLTAGE & POWER RATING	INDICATIVE STEP-OUT (4)	ADJUSTABLE SPEED DRIVE		POWER TRANS-FORMERS		NOMINAL TRANS-MISSION FREQ.	
		Radius (1)	Topside	Subsea	Topside (Step Up)	Subsea (Step Down)	50 or 60 Hz AC	16.7-25 Hz AC
Type 1	Capacity: 1-4 MW Transmission: ~6kV Distribution: ~6kV	0-15 Km (0-9.3 Mile)	●				●	
Type 2	Capacity: 1-4 MW Transmission: Up to 36kV Distr./Motor Input: ~6kV	0-60 Km (0-37.3 Mile)	●		● (2)	● (2)	●	
Type 3	Capacity: Up to 70 MW Transmission: 36kV-145kV Distr. Switchgear: Up to 36kV Distr./Motor Input: ~6kV	0-160 Km (0-100 Mile)		●	● (3)	● (3)	●	
Type 4	Capacity: Up to ~100 MW LF Transmission: Up to 145kV LF Dist. Switchgear: Up to 36kV Distr./Motor Input: ~6kV	>140-400 +Km (>87-248.5 +Mile)		●	● (3)	● (3)		●

Notes:
1. Indicative radius subject to system power rating. See Figure 1, Step-Out Configurations.
2. Transformer location likely after ASD to meet umbilical transmission voltage.
3. Transformer location likely before ASD to meet umbilical transmission voltage.
4. Stepout is the distance from the host facility.
5. Barracuda project with a step out of 14 km (8.7 Mi) is a deployed example of Type 1 Configuration.
6. Tyrihans project with a step out of 31 km (19.3 Mi) is a deployed example of Type 2 Configuration.
7. There is no deployed example of Type 3. Type 4 is currently conceptual.



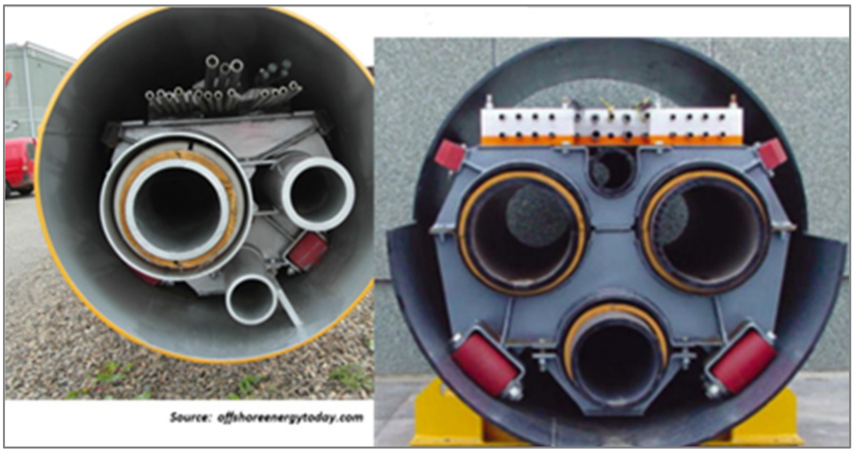
B.3.5.5 Subsea Flowlines

Subsea flowlines vary in form from simple steel or steel alloy pipe to those with special coatings or pipe-in-pipe bundles that provide thermal insulation. In deep waters, the cold seabed temperatures can quickly cool the fluids contained in or flowing through the production flowlines causing flowline blockages from wax or hydrate deposition.

Many forms of heated and/or insulated flowlines are now in service. Pipe-in-pipe technologies have achieved very high insulating and heating results and multi-functional duties; however, these solutions (like direct electric heating) will be extremely costly for very long distance subsea tiebacks and, likely, impractical for T&T's remote ultra-deepwater tiebacks. Even though there are a number of vertical flowline bundles installed in deep water (e.g., offshore Angola), the extreme hydrostatic pressures create considerable challenges for using even short flowline bundles and pipe-in-pipe sections in ultra-deep waters.

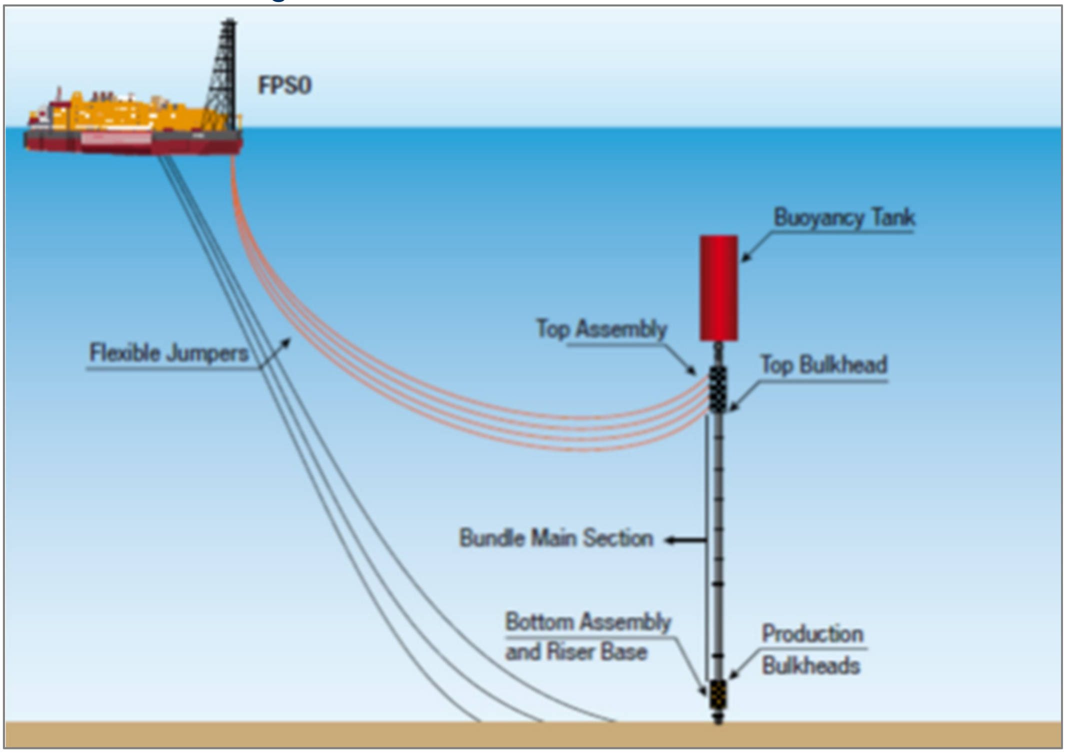
The sizes of flowlines and the "jumper" sections connecting the subsea trees to the flowline end terminations are usually well under 10 inches (250 mm) in diameter when handling flow from individual wells.

Figure B-25 Subsea Flowline Bundle Cross-Sections
(source: offshoreenergytoday.com)



There are many vessels and ways to install the small diameter lines – even in very deep waters. However, when the flow from many wells is commingled, the line sizes can be quite large, demanding very high capacity pipelay vessels (like AllSeas DP layship, Lorelay). The Jansz-Io field flowline to shore is an extreme example with a diameter of 30 inches (762 mm) that has been laid out to ~1,350 m water depth.

Figure B-26 Subsea Flowlines in Section



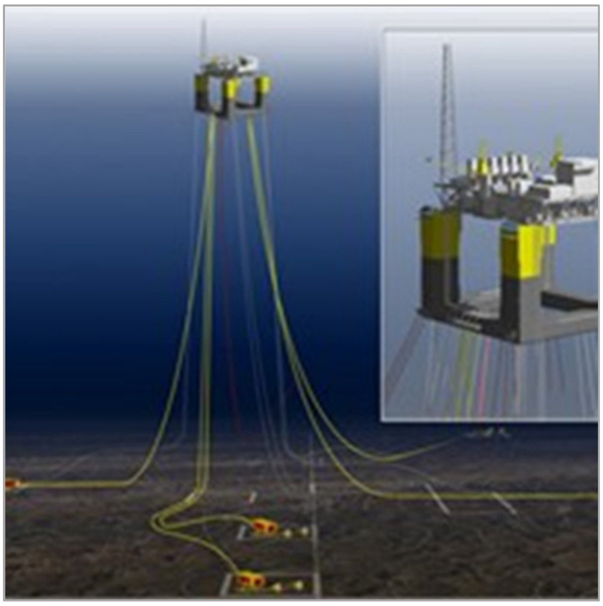
B.3.5.6 Risers

Risers are the connection between the subsea field developments on the seafloor and production and drilling facilities at the surface. They consist of a pipe or assembly of pipes used to transfer produced fluids from the seabed to the surface facilities or to transfer injection fluids, control fluids or lift gas from the surface facilities and the seabed.

Rigid Risers

Traditionally, "rigid" steel pipe risers were considered only applicable for direct, vertical tieback risers on Tension-Leg Platforms. However, over the past two decades, the industry (led by Petrobras) has successfully introduced "highly compliant rigid pipe risers" (HCRs) with the most popular form being Steel Catenary Risers (SCRs). Steel catenary risers have some limitations on the range of surface platform motion that can be accommodated so typically they are attached to platform types that exhibit limited vertical motion. However, in mild environments, they can be connected to barge or tanker hulls.

Figure B-27 Semi-Submersible Platform using Steel Catenary Risers
(Source: Rigzone)



A critical design issues for SCRs (actually any form of HCR), is the potential for flow induced vibration, commonly called "VIV" for vortex-induced vibrations. When the vortex-shedding frequency of a riser exposed to orthogonal flow (typically, the sea current) matches its natural frequency, the riser can be excited to vibrate in a way that can rapidly fatigue even these carefully manufactured steel pipe products. The harmonic excitation-response phenomenon is called "lock in". To "defeat" the tendency of smooth round riser cross-sections to become locked in, risers are often equipped with external vortex suppression devices. These devices have taken many patented forms (see Figure B-28 for an example). They are often clamped or glued onto the risers over sections where cross-flowing currents (or wave particle dynamics) are likely to generate VIV.

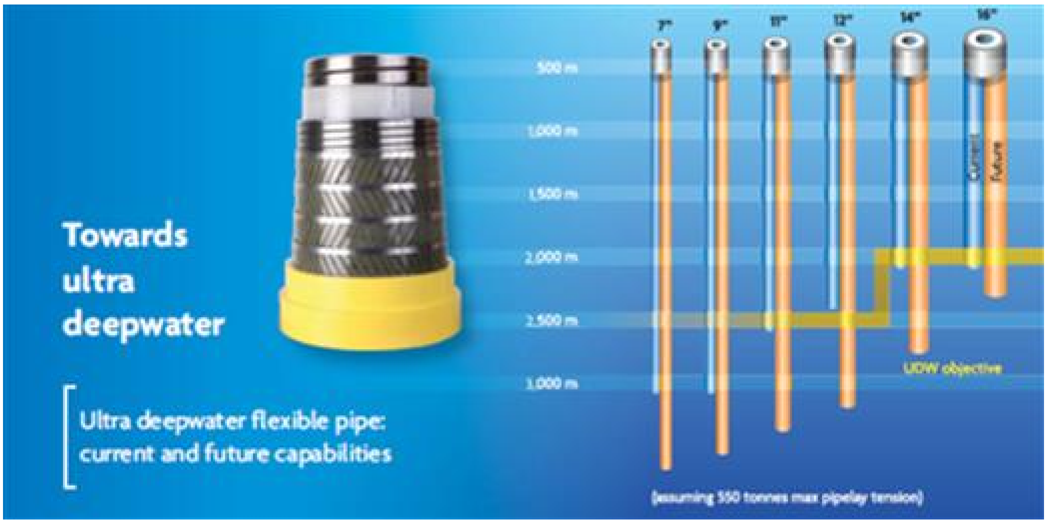
Unfortunately, while many forms of vortex defeating appendages can be successful, they also increase the mean drag load on the risers. Some manufactures provide directionally streamlined solutions that rotate on the riser pipe section to simultaneously defeat VIV and reduce the mean drag load.

Figure B-28 Vortex Suppression Devices
(Source: Marktool and LM-Offshore)

Flexible Pipe Risers

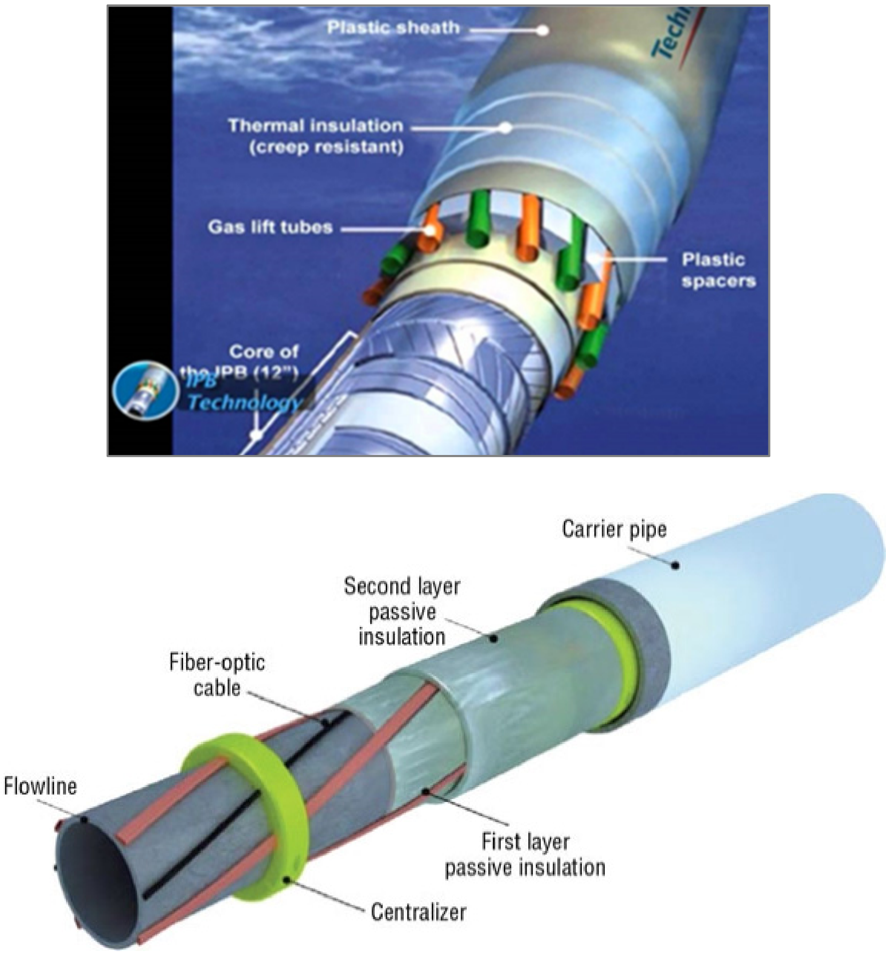
Very strong, durable materials and extremely high quality fabrication technologies have a range of applications in the manufacture of flexible riser pipe. The allowable water depth, driven by the external pressure rating of flexible pipe risers has been extended beyond 2000 m while the internal pressure rating now exceeds 10,000 psi, allowing highly productive wells to be tied back to floating facilities in ultra-deep waters. However, SCRs are often preferred due to the high cost of flexible pipe.

Figure B-29 Ultra-Deepwater Flexible Pipes
(source: Technip)



The high cost of flexible pipe is to some degree offset by the capability of the complex cross-section to include highly specialised features, such as heat tracing and monitoring technologies. Technip has developed and successfully deployed flexible pipe flowlines and risers in deep waters that include gas lift tubes while others include fibre optic temperature monitoring capabilities along with electrical heat tracing wires overlaying the primary pressure containment barrier layers (see Figure B-30).

Figure B-30 Complex, Multi-Function Flexible Riser Cross-Section
(source: Technip; offshore-mag.com)

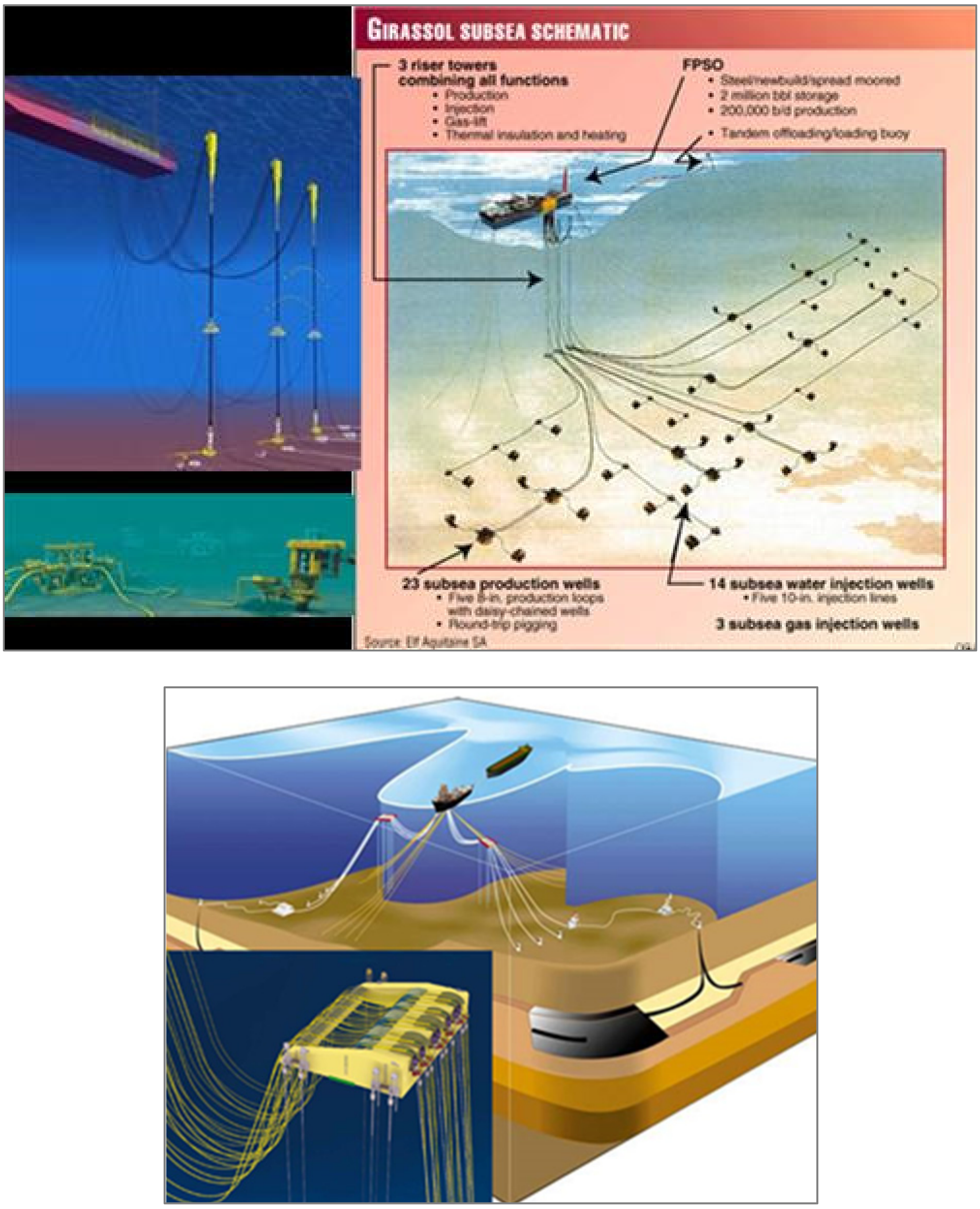


Hybrid Risers

Generally, the hybrid riser concept is adopted to allow flexible pipe to be connected between a submerged, buoyancy-supported "rigid" pipe section and a floating platform. The idea is to isolate the motions of the floating platform away from the rigid pipe section of the risers to minimise the fatigue in the steel pipes and direct it to the flexible pipe which can withstand the dynamics imposed by the floating platform. Many forms of hybrid risers have been installed which combine "rigid" steel pipe, flexible pipe, and buoyancy elements to bring production from very deep waters to surface facilities (e.g., hybrid riser towers for Girasol or offset Bouyancy-Supported Riser, "BSR", by Petrobras in Figure B-31). Petrobras adopted the BSR concept to limit the amount of flexible pipe required for tieback from seafloor to ship-shaped platforms fix-moored in the ultra-deep waters of their pre-salt plays because the flexible pipe risers are so expensive.

Figure B-31 Differing Schemes Implemented for Hybrid Risers in Ultra-Deep Waters

(sources: Saipem; Petrobras)

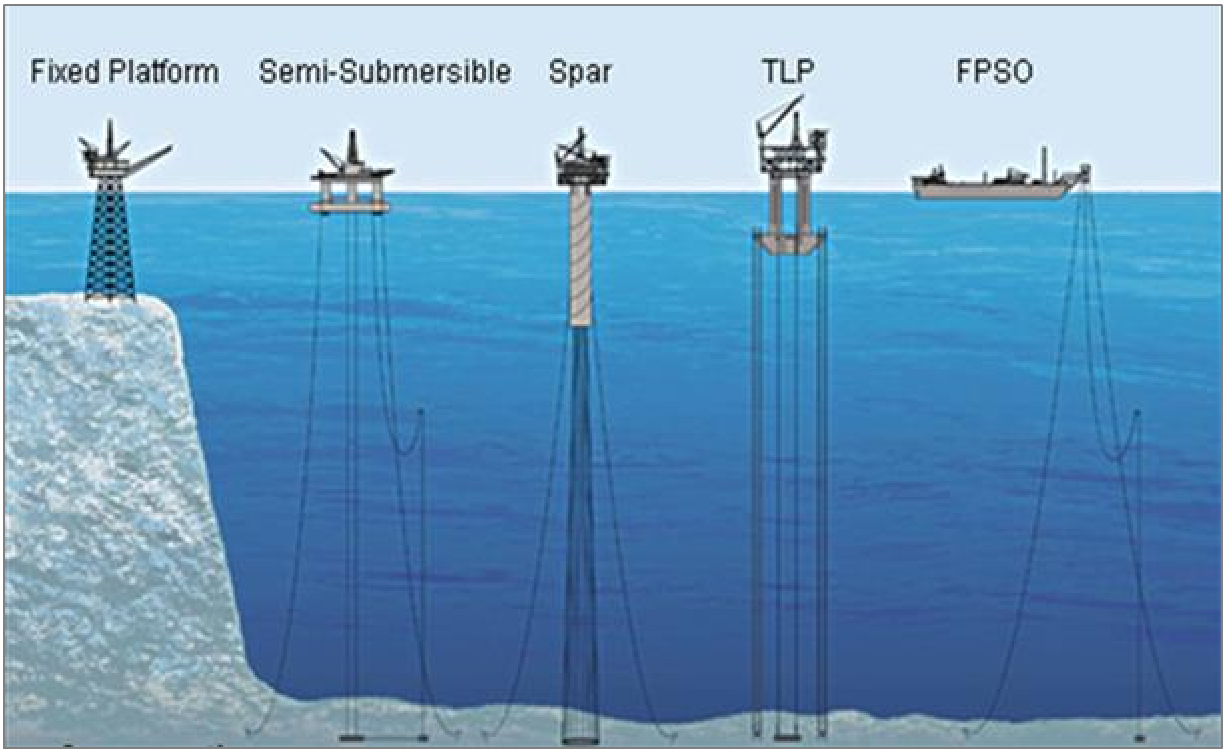


B.3.6 Deep Water Platform Options (Hull Forms and Platform Types)

The platform options can be divided into those capable of supporting "dry trees", where the wellhead is installed on the platform and those which must rely on "wet tree" wellheads installed on the sea bed. The "tree" or wellhead referred to here is the critical piece of equipment at the interface between the well and the flowline. It includes flow control and/or isolation valves that manage the flow of fluids from the high pressure rating wellbore to the medium pressure flowlines and processing facilities. The tree or wellhead also includes instrumentation and communication conduits which allow operators to manage its operations and monitor critical production parameters and smaller bore flow paths for downhole injection of production chemicals. The graphic presents a simplified view of the proven deepwater floating platform concepts (see Figure B-32 below).

Figure B-32 Proven Deepwater Platform Options

(source: offshore.com)



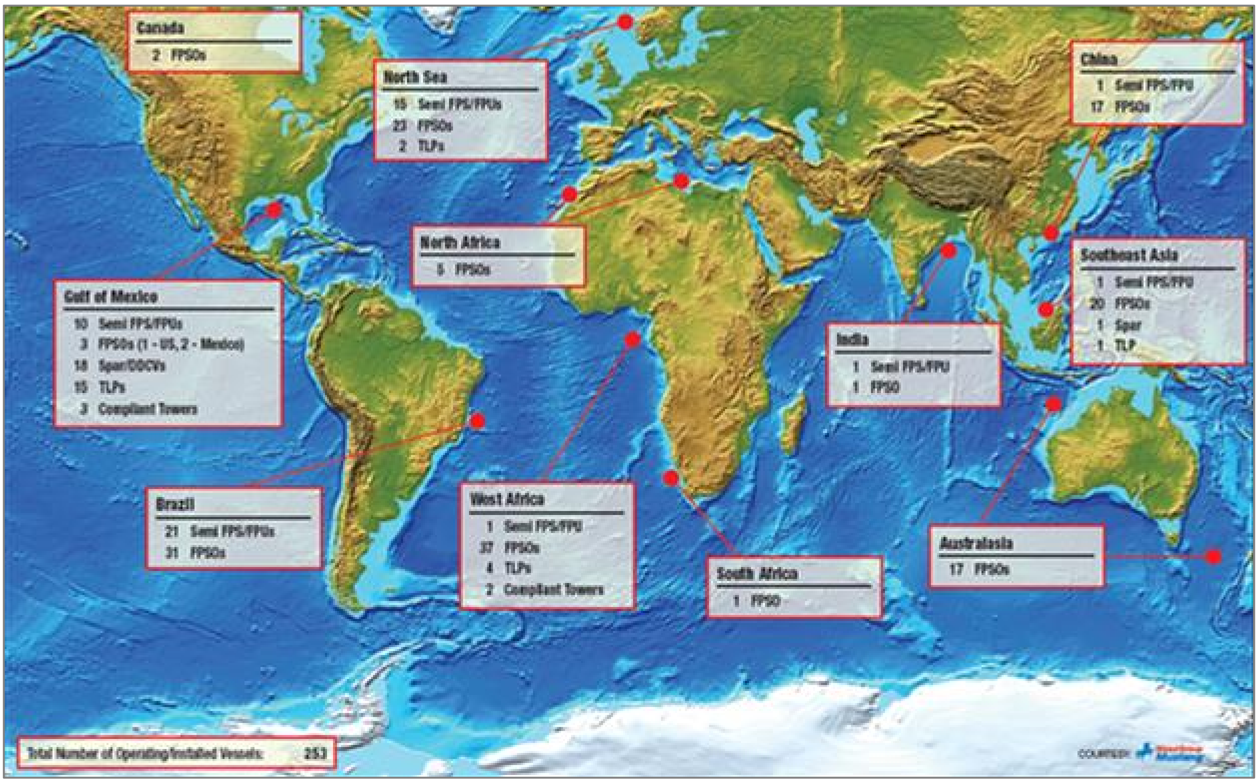
A tree is considered dry when it located in a normally dry ambient space (usually above the surface of the sea) sitting on top of a riser. The dry tree platform options are an important class of deepwater field development facility. Dry tree wells are often drilled and/or completed from the deck of the platform supporting the trees. Dry trees have the advantage of being more easily accessible, allowing fast and inexpensive re-entry to the well for wireline or recompletion activities with relatively light platform based equipment. Wet trees are located on the seabed, which gives far greater flexibility on the location of the wellhead in relation to the production platform, but re-entry to the well requires the time and expense of mobilising an offshore drill rig. The selection of a dry or wet tree development concept will therefore be influenced by the forecast frequency of well interventions.

Table B-3 Platform Type versus Water Depth

Deep water Platform Type (> 500ft WD)	Water Depth Range (typ.) (m)	Supports Dry Trees (or Wet only)	Provides Storage for Produced Liquids
Steel Tower	150-450	Dry	No
Tension-Leg Platform (incl. mini-TLP)	150-1500	Dry	No
Spar	450-3000	Dry	Possible, not proven
Semisubmersible	150-3000	No	No
FPSO	150-3000	No	Yes
Note – a few concrete towers serve in Norwegian waters (e.g., Troll at ~300m WD), but such tall concrete structures are not practical solutions for T&T waters.			

The world map in Figure B-33 shows the distribution of these platform types in 2012. A few of each type have been added in each basin over the past two years. Note that over the past two decades a number of operators have employed hybrid solutions, e.g. ExxonMobil's TLP+FPSO for the Kizomba field.

Figure B-33 Global Distribution of Deepwater Platforms
(source: Mustang Engineering, 2012)



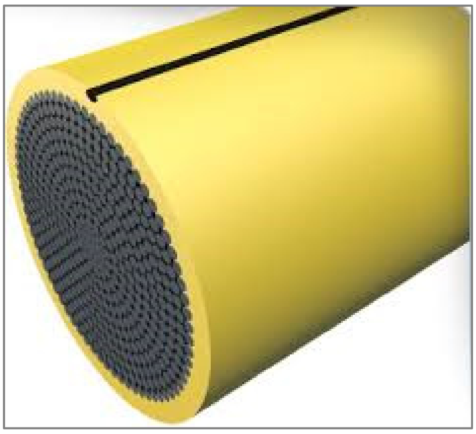
B.3.6.1 Platform Mooring and Positioning Systems

A common characteristic of deepwater platforms is the need for a mooring system to keep the floating platform in place once water depths exceed the economic limit for a fixed supporting sub-structure. Advanced anchor and mooring line technologies have allowed the installation of permanent floating facilities in ranges of water depth, metocean and soil conditions that cover the full extent of conditions anticipated for T&T's deepwater acreage. Vertical tension leg (tendon) moorings are now proven out beyond 5000 ft (>1,500 m) WD. The possibility of using carbon fibre materials to allow the TLP concept to used effectively out to 2,000 m WD has been explored but does not appear to be commercially feasible. Since the Triceratops concept does not experience the same harmonic excitation response problems as traditional TLPs, it is possible to use high strength vertical tension leg steel tendons to create a stable, vertically restrained platform facility in waters exceeding 2,000 m.

Figure B-34 Large Modern Mooring Ropes
(sources: Lankhorst)

Deepwater mooring lines can be made from high strength parallel spiral steel wires or braided polyester fibre ropes. Either can be manufactured to carry loads exceeding several million pounds. The spiral strand steel wire ropes can have breaking load capacities 2,500 te (>5,000,000 lbf). The steel wire ropes are much heavier and much less elastic than “poly ropes”. However, due to catenary effect of heavy lines in water, the neutrally buoyant “poly ropes” can actually hold deepwater floaters in a tighter “watch circle” (i.e., limit total offset). The service life of these modern rope products has also been greatly increased to avoid costly change-out operations. Properly coated steel wire rope can offer service life up to 15 years.

Figure B-35 Spiral Strand Steel Wire Rope Cross-Section
(source: Bridon)



Bluewater’s Munin dynamically-positioned FPSO has been put into service with an external turret that offers the potential for eliminating the costs and complexity of a deepwater mooring system completely. A DP FPSO may be the best solution in areas where soil conditions present serious challenges to anchoring spread moorings (like the Browse basin off NW Australia). Australia’s Woodside Energy Ltd has even filed patent for a DP FLNG concept; however, due to the potential for cyclone interruptions of service and emergency disconnects caused by DP failure (e.g., drive- or drift-off events), the connection to the subsea systems and wells must be very simple and robust. This will tend to limit this deployment of this concept to smaller fields with relatively few wells.

B.3.6.2 FPSO

FPSOs are the most popular of the standalone deepwater oil field development production facilities with over 150 units installed globally. The world map in Figure B-33 above shows the wide distribution and popularity of FPSOs as deepwater production units. The production capacity of FPSOs has varied greatly (from less than 50 Mboe/d for the lowest cost conversion projects to well over 200 Mboe/d for the largest, most complex units). The technology is well-proven in water depths and metocean conditions relevant to T&T's exploration frontier and must be considered a leading candidate for development of oil reservoirs. The FPSO solution tends to provide a lower cost option than platforms that provide drilling capability and/or direct well access. However, if a large number of expensive wells are required and/or the operator expects that the wells will need frequent intervention work, then the savings on well construction and operating costs can push for selection of the more costly platforms. It is possible that as much as $50M/well could be saved by drilling from a platform compared to a subsea well, but this must be offset against the cost of platform installation.

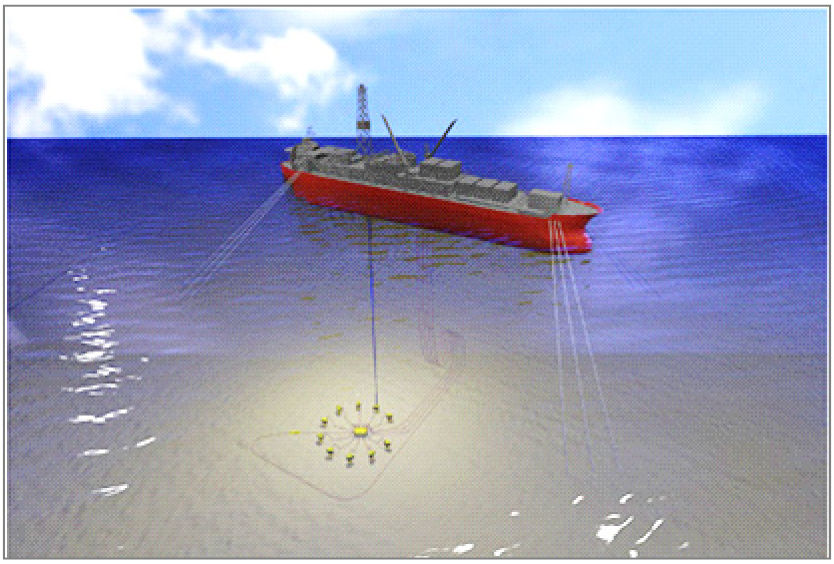
If the discovery is a gas reservoir that appears to require an infield processing, then a gas processing FPSO may be considered. The largest and most complex example is the Prelude FLNG vessel, expected to cost over $10B. Prelude will process a fairly rich well stream into LNG, LPG and condensate projects requiring extensive processing, storage and offloading facilities on the largest man made floating structure ever built. Due to the existence of liquefaction facilities onshore Trinidad, it is unlikely that FLNG technology will be adopted in T&T waters. However, a gas processing FPSO could extract NGLs and condensates to allow a dry gas stream to be sent over a relatively great distance to shore. The Ichthys development off Western Australia, employs both a semisub FPS and a gas processing/liquids handling FPSO. It is possible that a gas-FPSO off T&T could serve field development needs without the inclusion of another floater. The high cost of including an FPS at Ichthys appears to have been justified by the great number of large high pressure risers that needed brought to the surface.

Most FPSOs are basic monohulls (barges or ship-shape). However, the past decade has also seen the introduction of a "big buoy" option (e.g., the Sevan buoy in Figure B-36). These buoys have been deployed in some severe weather locations, e.g., the North Sea. However, their motions in swell conditions are not favourable. The motions of a big buoy in Atlantic swell conditions are definitely not as favourable as those for a semisubmersible but the storage option may make them a commercially attractive option for smaller oil fields.

Figure B-36 Sevan FPSO in Service
(source: Sevan Marine ASA)

Murphy adopted the world's first FPSO with drilling facilities (FDPSO) for the Azurite field offshore West Africa (see Figure B-37). The unit has been released from service but it did prove the concept to be feasible in an area where weathervaning (and, thus, turret mooring) is not required. However, this concept is not appropriate for the waters off T&T where extreme weather (e.g., hurricane winds and waves) can come from any direction. Such conditions require that the unit have a shape that is omni-directional (like Sevan's FPSO and drilling rig buoys) or be provided with a weathervaning capability.

Figure B-37 FDPSO as Conceived for Murphy's Azurite Field
(source: Doris Inc)



B.3.6.3 Semisubmersible (Semisub)

The first floating production facility was based on conversion of a drilling semisub for service as an FPF (or FPS) at the Argyle field the North Sea. Now, there are a great number in use around the world with more than a dozen installed in waters over 1,000m deep. Semisubs can be designed and built to carry massive payloads supporting production rates over 200 Mboe/d. Few, like BP's Thunderhorse, have drilling facilities onboard. Typically, wells are drilled as remote subsea tiebacks by chartered drilling rigs.

In 2007, the Independence Hub was installed in 8,000 feet of water approximately 123 miles offshore as the deepest production platform ever installed and the world's largest offshore natural gas processing facility with a capacity of 1 Bcf/d by late 2007. The Independence Hub is a 105-foot, deep-draft, semi-submersible platform with a two-level production deck. The platform is operated by Anadarko and owned 80 percent by Enterprise and 20 percent by Helix. The Independence Trail pipeline, 100-percent owned and operated by Enterprise, connects the Hub platform to onshore markets via an interconnect at Enterprise's West Delta Block 68 shallow-water manifold platform. The pipeline is approximately 134 miles long, 24 inches in diameter and has the capacity to transport up to 1 Bcf/d. The Independence project set numerous world records during its construction and installation, which include:

- The world's deepest platform in approximately 8,000 feet of water.
- The world's deepest subsea production tree in 9,000 feet of water at the Cheyenne field.
- The world's deepest steel catenary riser (SCR) installation.
- The world's deepest export pipeline and SCR, originating in approximately 8,000 feet of water.

US independent ATP attempted to introduce the world's first dry-tree semisub. The huge deep-draft steel hull (see Figure B-38) was built in China for deployment to the Cheviot field in the UK but was never delivered to the now bankrupt operator and the deck was never attached. This case was a failure of the company, not the concept. Although there are many concepts for dry tree semisubs, to date, no semisubs have been deployed with dry tree well tiebacks.

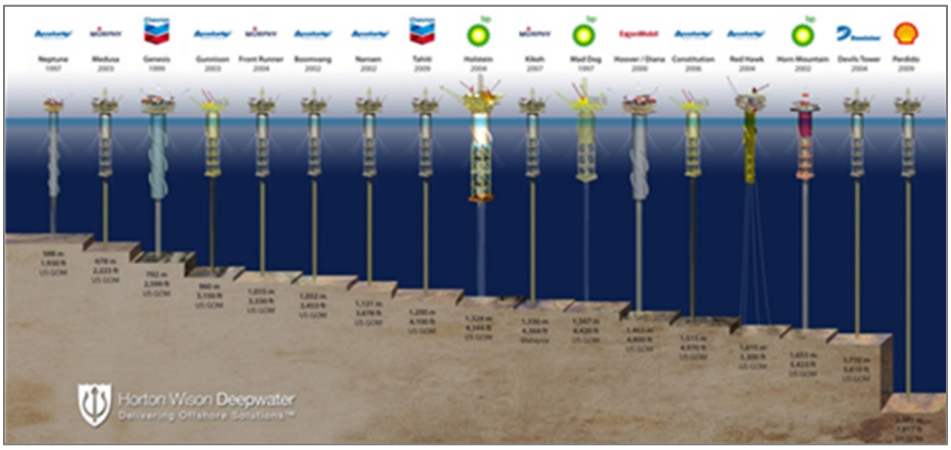
Figure B-38 Hull of Dry Tree Semisub Built for ATP

(source: offshore.no)

B.3.6.4 Spar

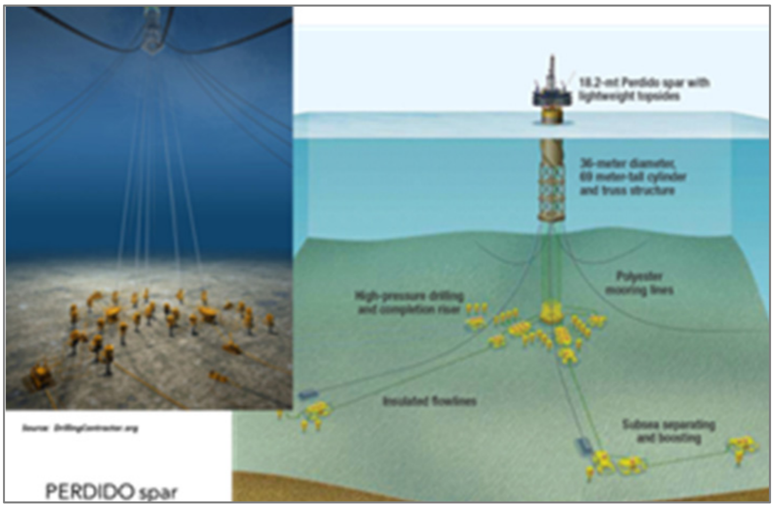
Since the first “dry tree” well and production system spar, Oryx’s Neptune, was installed almost 20 years ago in the US GoM, the technology has been widely adopted in regions not subject to onerous swell conditions. Technip leads the world with provision of 19 of the spars installed worldwide. The following graphic gives a good idea of the evolution and adaptability of this useful platform concept (see Figure B-39). Though it is feasible, as yet, no operators have employed the option as originally conceived as a combined production and storage facility. Shell’s Brent spar was installed in the North Sea to store produced fluids within the hull but with no topside production capability.

Figure B-39 World-Wide Line-Up of Spar Platforms
(source: Horton Wison)



Shell’s record setting Perdido development was built around a spar that can complete wells and produce from dry trees, as well as being the hub for production from subsea wells at surrounding fields (see Figure B-40). The Perdido spar hull is of the spar type know as a “truss spar” which offers a great reduction in steel weight and construction cost as compared to the original “classic spar” concept. The truss spar is the most common form installed in recent years. The Red Hawk spar introduced the “cell spar” concept which is intended to further reduce construction costs.

Figure B-40 Shell’s Perdido Spar and Neighbours
(source: DrillingContractor.org)



B.3.6.5 Tension-Leg Platform (TLP)

The TLP concept was first patented in the 19th century. Almost 100 years later, the Hutton TLP was installed by Conoco in approximately 150 m WD in the North Sea. Now, a vast array of TLP solutions has been implemented in much deeper waters and in a wide range of metocean conditions. TLP hulls have from 1 to 4 columns with mooring tendons ("tension legs") connected at the extremities to constraint vertical responses, providing a stable platform for drilling wells and attaching vertical tieback risers. The following graphic indicates the range of TLP solutions that have been deployed globally (see Figure B-41). It is a highly flexible concept which provides dry trees and direct well access from the surface. ExxonMobil used a TLP to drill the central wells and an FPSO for production, storage, and export of oil from the Kizomba field in deep waters off Angola (see Figure B-42). TLP's have been deployed to almost every offshore theatre; Petrobras has recently installed a TLP in 1,180m WD at the Papa Terra field and, until recently, Premier was proposing a TLP for the Sea Lion field in the south Atlantic basin.

Figure B-41 TLP Configurations
(source: various)

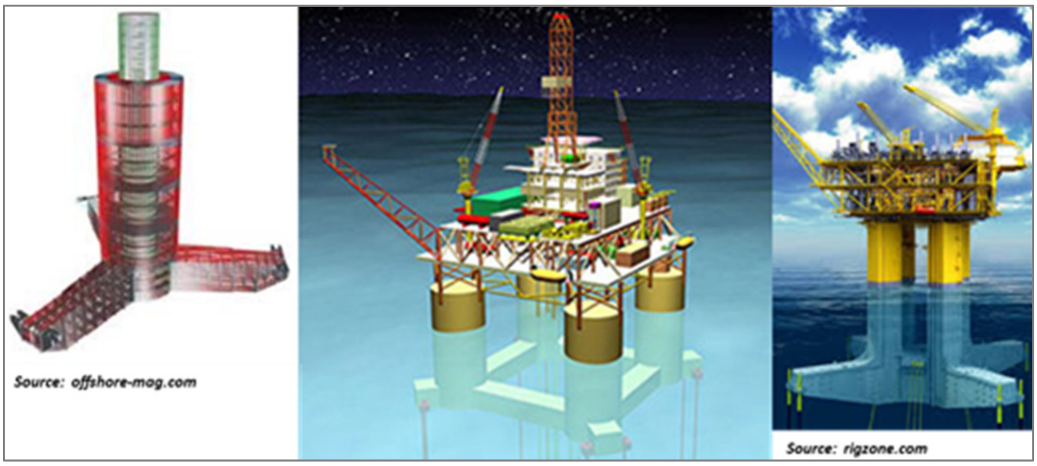
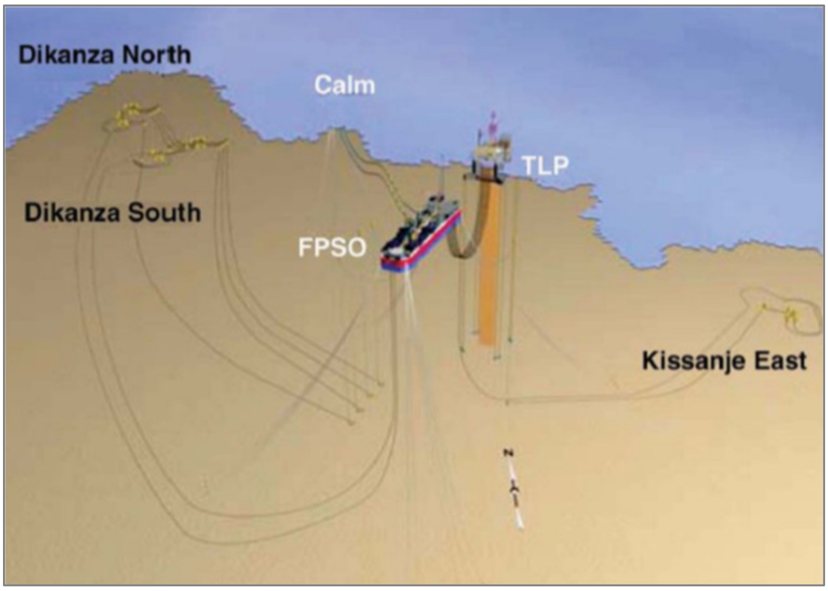


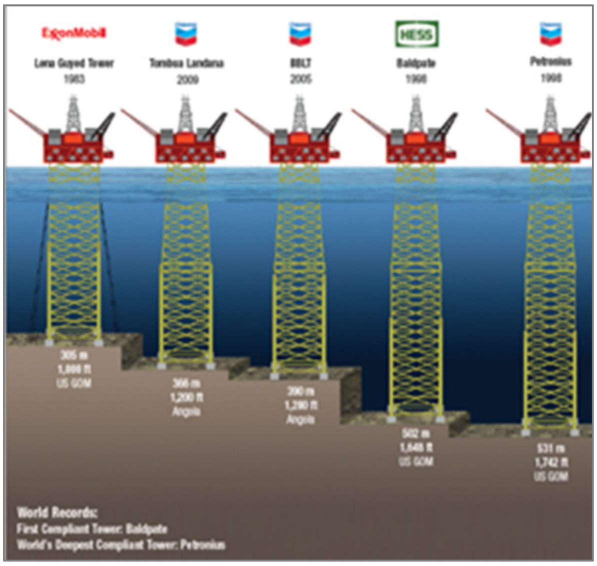
Figure B-42 Kizomba B Field – Development Concept
(source: Esso Angola SA)



B.3.6.6 Tower

Jacket type tower structures have been deployed into water depths exceeding 500 m but are not appropriate much beyond that depth. The seismic activity and design criteria for the region also factor into an assessment that the option will have limited the applicability as a deepwater solution for T&T.

Figure B-43 Compliant Towers Stretching to Deeper Water
(source: Mustang Engineering)



Buoyant towers have been installed in harsh environments to provide a bottom-founded alternative to traditional jacket structures but, as yet, none have been used as major production facilities in deep waters. The simple concepts, like the Triceratops, offer great ranges of payload and water depth capabilities.

Figure B-44 A Buoyant Tower Concept
(source: Capanoglu, IDEAS)

B.3.7 Processing Facilities

Platform-based processing systems have proven capable of handling a wide range of reservoir and produced fluid characteristics. There is not likely to be any limitations on the ability of industry to provide a highly reliable solution for discoveries offshore T&T. The more interesting aspect is the role of seabed (or even downhole) separation and the role that it might play in reducing the costs of or increasing the hydrocarbon recovery for future developments offshore T&T.

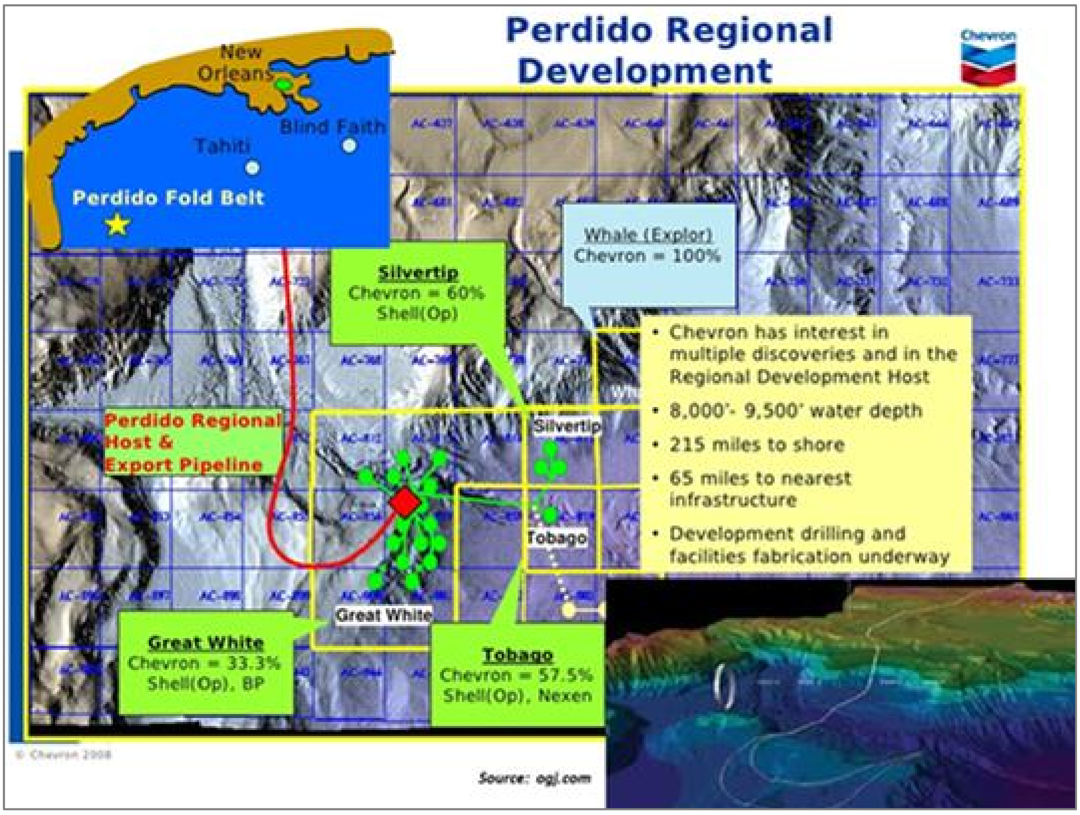
B.3.8 Export Systems

B.3.8.1 Pipelines

Pipelines and the relevant installation equipment today have been proven for applications quite relevant to ventures off T&T. ExxonMobil's Diana-Hoover and Shell's Perdido projects have proven that large diameter, long export pipelines (as well as infield flowlines) are well within industry capabilities. Both projects addressed the challenges of climbing up the complex GoM slope terrain to the continental shelf.

Prior to Perdido, the Independence Trail pipeline from the Independence Hub production facility had the world's deepest export pipeline and SCR, originating in approximately 8,000 feet of water. The pipeline is approximately 134 miles (216k m) long, 24 inches in diameter, and has the capacity to transport up to 1 Bcf/d of gas.

Figure B-45 Developments in the GoM Have Required Very Long Pipelines
(source: Chevron)



B.3.8.2 Tanker/Shuttle Export Vessels (Ships & Barges)

Export of liquids from existing shallow water developments offshore T&T to the onshore midstream and downstream industries is achieved through a network of liquid pipelines running in parallel to the gas pipeline network.

As the industry moves into deeper water and much farther from shore, it is possible that shuttle vessels or export tankers may prove to provide a more practical means for getting liquids to the onshore industry. Shuttles have proven to operate effectively in many remote and severe weather locations.

B.3.9 Support Equipment/Systems for Installation and Operations

B.3.9.1 Heavy-Lift Dry Transport Vessels

The lifting capacities and transport speeds of the current world fleet allow efficient delivery of massive structures. Offloading can occur in well protected waters relatively near to T&T's deepwater acreage.

Figure B-46 Semisubmersible Heavy Lift Carriers Provide Efficient Transport
(source: Dockwise)

B.3.9.2 Heavy-Lift Units for In-field Support

The already impressive capability of the heavy lift fleet has recently been augmented by the introduction of Allseas Pieter Schelte. In addition, the US GoM and West Africa keep many of the world-class heavy-lift semisubs working and within reasonable mobilisation distances to T&T's waters.

Figure B-47 The Pieter Schelte Provides Record Lift Capacity
(source: AllSeas)

Engineers for the major service providers are experienced in dealing with the challenges of accurate water depth measurement and the impact of currents and motions on the operations involved in remotely placing, securing, and connecting the components of highly complex subsea systems.

B.3.9.3 ROVs and Robotics

The ability of the industry's fleet of deepwater robots (ROVs) to accomplish a wide array of tasks is already well proven. In very deep waters, the installers depend highly on operations by and feedback from ROVs. Today's ROVs are highly powered and provide enhanced payload capabilities. The immediate and near future will see more success with autonomous ROVs. Currently there is no reason to have concern about the industry being able to support all operations that might be required on T&T's deepwater frontier.

B.4 POTENTIAL IMPACT ON T&T GAS DEVELOPMENTS

The potential for new and emerging deep water development technology to impact upon the commercialisation of gas fields offshore T&T has been assessed and is documented in the table below.

Table B-4 Potential Impacts of Deepwater Development Technology on Commercialisation of Gas Fields Offshore Trinidad and Tobago

TECHNOLOGY	High / Medium / Low impact on:		
	HC Recovery	Well Count	Production Flexibility
General:			
Decision making	M Improved DQ helps clarify the optimal development path forward for all participants; also, DQ can either drive earlier or later abandonment depending on many factors, including value of production (price) or government ability to inspire extended recovery efforts.	M Improved DQ will help operators successfully adopt new technologies.	H Advanced DQ methods can be used to determine when pilot or staged production approaches make sense. In a world of rapidly evolving technologies, D&RA methods can put a value on future technologies to indicate whether facilities for long-lived fields should allow for future innovations.
IT and data management	H Improved understanding and management of reservoirs as well as development projects and facilities.	M Likely to improve the targeting of wells so that fewer will be misplaced (requiring additional wells to meet production targets).	L Better understanding of the assets can mean that elements may be used more flexibly.
Project Management	L-M Better PM should mean that assets will perform as intended.	L	L
Materials, coatings, manufacturing, and welding	M Enabling some of the specific technologies noted herein.	M Enabling some of the specific technologies noted herein.	M Enabling some of the specific technologies noted herein.
Integrity monitoring and management	M Assets should be able to meet their intended service lives reliably.	N.A.	N.A.
Safety and risk management / analysis	M Assets and humans should be able to serve safely and reliably.	N.A.	N.A.

Subsurface:			
Improved seismic data acquisition and interpretation	H Professionals adept with advanced technologies will maximise the value of HC reservoirs.	M Only truly valuable wells will be drilled.	L G&G professionals will tend to push for optimisation – not flexibility.
Geomagnetic enhancement of seismic data (2D or 3D)	? TBD – Rocksource, the Norwegian company most committed to capability, has not had significant success with the methods or its business model to date.	? TBD	? TBD
Modeling and data mining advances enabled by computing power and programming breakthroughs	H Professionals adept with advanced technologies will maximise the value of HC reservoirs.	M Only truly valuable wells will be drilled.	L G&G professionals will tend to push for optimisation – not flexibility.
Drilling:			
Improved safety systems and practices	L	M It is possible that some of the more aggressive, advanced drilling practices will be avoided or even prohibited.	L
Advanced Measurement-While-Drilling (MWD) methods	M Wells should effectively reach their intended targets.	M Only truly valuable wells will be drilled.	L More of an optimisation tool.
Extended reach, horizontal and "snaking"well bores	H A single wellbore can have a greatly increased interface with targeted formation, increasing the potential deliverability and recovery per well, particularly in low permeability formations.	H A single wellbore can have a greatly increased interface with targeted formation, increasing the potential deliverability and recovery per well, particularly in low permeability formations. Greater recovery and deliverability per well should mean that fewer wells will be required.	M This technology may allow unevenly distributed (tight or fractured) target formations to be produced from a single location.

Multilateral wellbores	M Decreasing the cost per completion by aggregating multiple wellbores within one wellhead can mean that the development budget can cover an increased number of completions. In general, this should mean an opportunity for increasing recovery.	H A single wellhead can serve as the conduit for multiple diverted bore paths, greatly expanding the drainage area and/or reaching additional targeted formations, increasing the potential deliverability and recovery per well… meaning fewer wellheads (wells) will be required.	M If a wellbore can allow multiple deviations, it is possible that the reservoir engineers can more easily adjust reservoir exploitation plans in accordance with insights gained during production.
Sub-salt (through salt) drilling	M-H If salt is a substantial feature in T&T's deepwater plays, the fact that drillers can competently manage the related drilling challenges will be very important.	L Not a significant factor in reducing well count.	M If salt is a substantial feature in T&T's deepwater plays, the fact that drillers can competently manage the related drilling challenges should increase flexibility.
Ultra-deep and HPHT wells	M-H If these challenges feature substantially in T&T's deepwater plays, the fact that drillers can competently manage them will be very important in determining what can be recovered.	L Not a significant factor in reducing well count.	M If these challenges feature substantially in T&T's deepwater plays, the fact that drillers can competently manage them could be important in creating development options.
Well Systems and Completions:			
Reservoir (recovery) optimisation	H Optimisation of reservoir drainage will improve hydrocarbon recovery.	M Well informed reservoir engineers may actually push for more wells than would have been expected in the past; however, these wells will be highly justified.	L Pushing for optimisation may actually limit flexibility.
Intelligent completions	H Improved information about and control of the producing asset should enable enhanced recovery.	M-H Improved information about the producing asset may actually support arguments for more wells.	H The ability for reservoir engineers to gather more and better information about the producing asset in "real time" should push for the adoption of more nimble development schemes.

Multi-zone and multilateral completions	M Decreasing the cost per completion by aggregating multiple wellbores and completing multiple zones within one wellhead can mean that the development budget can cover an increased number of completions. In general, this should mean an opportunity for increasing recovery.	H A single wellhead serving as the conduit for multiple completions should increase the potential recovery per well… meaning fewer wellheads (wells) will be required.	M If a wellbore can allow multiple deviations, it is possible that the reservoir engineers can more easily adjust reservoir exploitation plans in accordance with insights gained during production.
Tieback Systems:			
Subsea Trees	M In the sense that modern trees are highly reliable and can accommodate highly complex completion tiebacks as well as advanced data acquisition systems, the technology can influence the successful exploitation of deep and ultra-deep water reservoirs.	H In the sense that modern trees are highly reliable and can accommodate highly complex completion tiebacks, they support the ability to greatly reduce the number of wellheads required to develop a field.	H In the sense that modern trees are highly reliable and can accommodate highly complex completion tiebacks, they greatly increase development and production flexibility.
Controls	M As with Subsea Trees (see above)	H As with Subsea Trees (see above)	H As with Subsea Trees (see above)
Umbilicals	M As with Subsea Trees (see above)	H As with Subsea Trees (see above)	H As with Subsea Trees (see above)
Power Supply	H In the sense that delivery of power to remote subsea or downhole pressure boosting facilities should increase the recovery per well, the impact on total recovery can be high.	H In the sense that delivery of power to remote subsea or downhole pressure boosting facilities should increase the recovery per well, the impact on total number of well can be high.	H The ability to deliver power to remote pressure boosting facilities should have a significant impact on the choice of development options and the ability to accommodate new insights.
Subsea Flowlines	L The durability of modern flowlines may mean that fields can be kept onstream longer.	N.A.	M The options introduced by the wide range of modern flowline products does enhance the flexibility.
Risers Rigid Flexible Hybrid	L The durability of modern risers may mean that fields can be kept onstream longer.	N.A.	M The options introduced by the wide range of riser products does enhance the flexibility.

Floating Platform Options (Hull Forms and Platform Types):			
FPSO	L No significant impact on recovery.	L No significant impact on well count.	H Can be deployed to great water depths and can carry massive payloads. Due to ability to disconnect or operate on DP, there can be great savings on ultra-deep water moorings which generally makes the FPSO option the most flexible.
Semisubmersible (Semisub)	M .	M The ability to drill and maintain wells from the facility may allow the ability to reach more targets through one wellhead (reducing "well count"); while, alternatively the reduction in cost per well can mean more wells can and will be drilled.	H Can be deployed to great water depths and can carry massive payloads. Also, can support drilling and/or well intervention equipment so wells can be drilled or repaired when needed.
Spar	M The ability to support dry trees and providing direct well access is generally considered to improve the ultimate recovery from reservoirs.	M The ability to drill and maintain wells from the facility may allow the ability to reach more targets through one wellhead (reducing "well count"); while, alternatively the reduction in cost per well can mean more wells can and will be drilled.	M Can be deployed to great water depths. Also, can support drilling and/or well intervention equipment so wells can be drilled or repaired when needed.
Tension-Leg Platform (TLP)	M The ability to support dry trees and providing direct well access is generally considered to improve the ultimate recovery from reservoirs.	M The ability to drill and maintain wells from the facility may allow the ability to reach more targets through one wellhead (reducing "well count"); while, alternatively the reduction in cost per well can mean more wells can and will be drilled.	M Can carry great payloads and , can support drilling and/or well intervention equipment, but water depth is limited as compared to other floaters.
Tower	M The ability to support dry trees and providing direct well access is generally considered to improve the ultimate recovery from reservoirs.	M The ability to drill and maintain wells from the facility may allow the ability to reach more targets through one wellhead (reducing "well count"); while, alternatively the reduction in cost per well can mean more wells can and will be drilled.	L Very limited water depth.

Mooring systems	N.A.	N.A.	M From vertical tension legs to taut-leg spread moorings to full DP, field developers have a flexible tool kit for keeping floaters on station in deep waters.
DP production facilities	N.A.	N.A.	H See above and FPSO.
Processing Facilities:			
At the surface	M Water or gas reinjection can maintain or enhance recovery and in many fields is planned from the start. Gas lift provides a proven option for limiting back pressure on the reservoir.	M Requirements for reinjection tend to increase well count; however, this delta is not "caused" by the facilities.	M Compact or higher efficiency designs for equipment tend to increase topsides design flexibility but has little impact on production flexibility. "Plug and play" features are likely to have more impact.
Seabed (or even downhole) separation and boosting	H The possibility of limiting back pressure on the producing formations can mean a substantial increase in recovery.	L Likely to have only indirect impact on well count.	H Pressure boosting at the field enables very remote tiebacks.
Gas handling and disposal management (re-injection challenges)	M Can be factor if gas reinjection is required for pressure maintenance… especially if gas supply is inadequate or if excess gas disposal is a real constraint.	M May cause a need for additional wells.	M Gas reinjection or disposal requirements or constraints can limit the range of production options available to planners.

In-field Storage Options:			
FPSO or FSO barge/ship hulls	N.A.	N.A.	M Having the ability to store/export independently of existing infrastructure introduces some production flexibility.
Spars	N.A.	N.A.	M As for FPSOs, but not truly proven.
Export Systems:			
Pipelines	M If there is a requirement to use existing export lines, development and recovery may be constrained.	N.A.	M If there is a requirement to use existing export lines, development options may be constrained.
Tanker Vessels (ships & barges)	N.A.	N.A.	M Having the ability to store/export independently of existing infrastructure introduces some production flexibility.
Support Equipment/Systems for Installation and Operations:			
Heavy-lift dry transport vessels	N.A. .	N.A.	M The capabilities of the modern fleet mean that field developers have almost no constraints on what they can bring to the field.
Heavy lift units for in-field support	N.A. .	N.A.	M The capabilities of the modern fleet mean that field developers have almost no constraints on what they can install at the field.
ROVs and robotics	M Improved systems and equipment for very remote production operations are making it possible to employ advanced production systems in very deep waters.	N.A. Unless nano-bots can drill & complete wells!	M The capabilities of the modern fleet mean that field developers have almost no constraints on what they can do in the field or downhole.

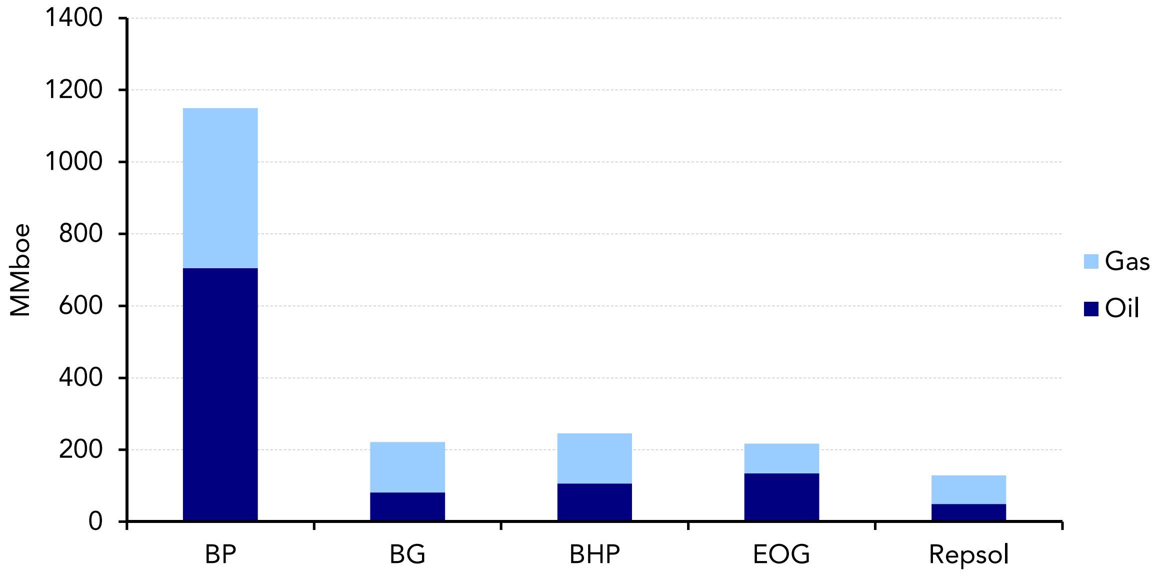
C.1 BACKGROUND

The five main incumbent companies active in the upstream sector in T&T are: BP, BG, BHP, EOG and Repsol. This appendix seeks to provide some background analysis on their global activities in order to provide some context for their positions in T&T.

Among the five incumbent companies, BP was by far the largest oil and gas producer in 2014 (BP's production was around 5 times bigger than BHP's production). BP and EOG are more focused on oil (around 60% of total oil and gas production) while BG, BHP & Repsol are stronger in gas production (again ~60% of total oil and gas production). Oil and gas production figures for each company are shown in the figure below.

Figure K-1 Global Production of T&T Upstream Incumbents (2014)

(source: company Annual Reports)



BP and BG have highly diverse portfolios. BP's principal areas of production in 2014 were Angola, Argentina, Australia, Azerbaijan, Egypt, T&T, the UAE, the UK and the US.

, while BG produces similar volumes in Egypt, UK, Kazakhstan and T&T. However, EOG and BHP's production is highly concentrated in the US, which accounts for around 90% and 60% of company production respectively. Australia is also an important region for BHP. Repsol's production is largely focused on the US and Brazil.

Currently, BP and BHP want to expand deep water exploration, and the both have strong position in Gulf of Mexico area. BP also successfully keep its deep water exploration in Brazil, Angola and North Africa.

The information provided below is almost exclusively extracted from each company investor information package (annual reports, investors presentation etc.).

C.1.1 BP

C.1.1.1 Strategy

Post-Macondo BP has implemented a strategy to divest various assets and attempt to retain a more focused footprint of quality assets, covering deepwater, gas value chains, and giant fields, with a growing proportion of its operating cash flow coming from gas value chains, projected to rise from 35% currently to around 45% by 2024. BP has already completed a $38 billion divestment program by the end of 2014 and plans for a further $10 billion of divestments before the end of 2015, with half already settled.

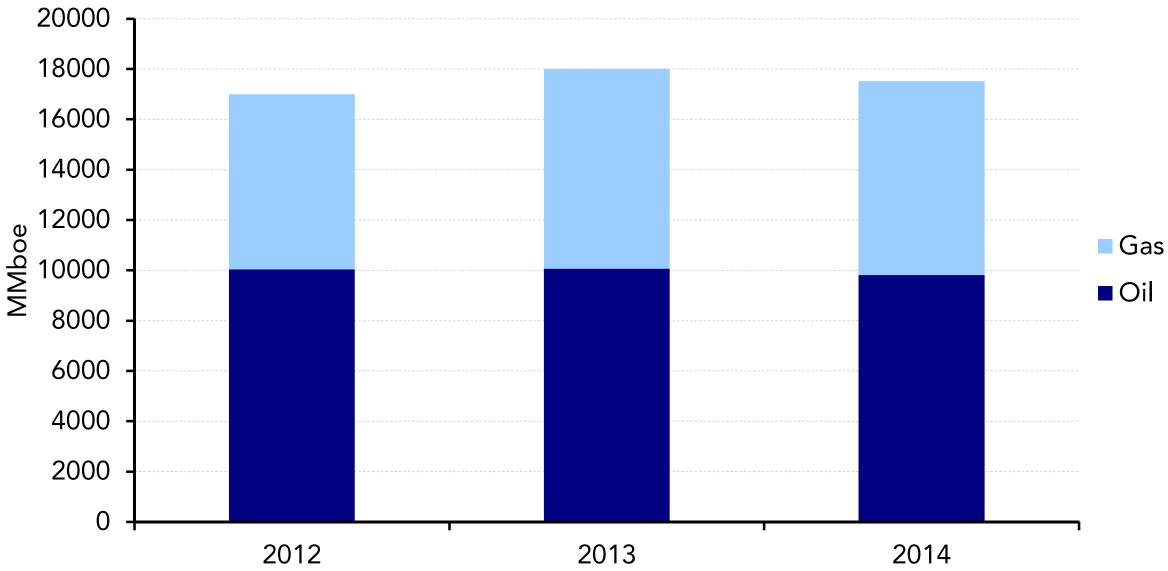
BP expects to generate more than 75% of its production and operating cash flow by 2020 from existing fields or projects currently under construction. Half of the estimated amount is expected from BP's key regions which are Angola, Gulf of Mexico, Azerbaijan and the North Sea.

C.1.1.2 Activity

Reserves & Production

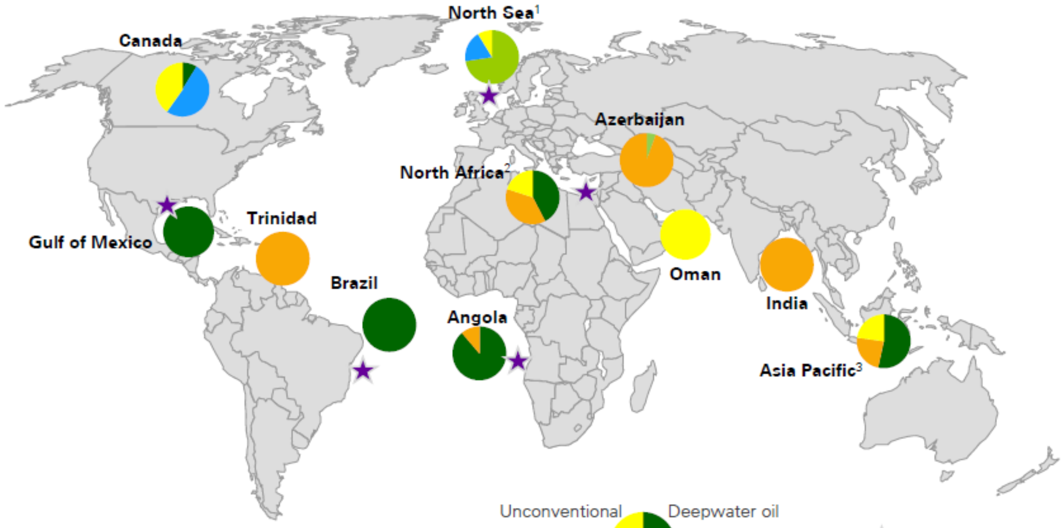
As of the end of 2014 BP's estimated total proved reserves of oil and gas stood at 17,523 MMboe (56% oil and 44% gas). This figure has held relatively steady over the past 3 years, as shown in the figure overleaf, despite the divestment process.

Figure K-3 BP Total Proved Oil & Gas Reserves
(source: BP Annual Report 2014)



In terms of exploration BP currently has a balanced portfolio with diverse drill-out options. BP drilled 15 to 20 wildcat wells per year in the past several years, and the company plans to test 15 to 20 new plays in 2014-2018. BP has deepwater drilling interests in several countries, and it is pursuing further deepwater growth opportunities in Angola (core exploration), Australia (frontier exploration), Brazil (core exploration, frontier exploration), Canada (frontier exploration), the US (near-field exploration, core exploration) and Morocco (frontier exploration) in 2014-2018.

Figure K-5 BP Exploration & Resource Appraisal

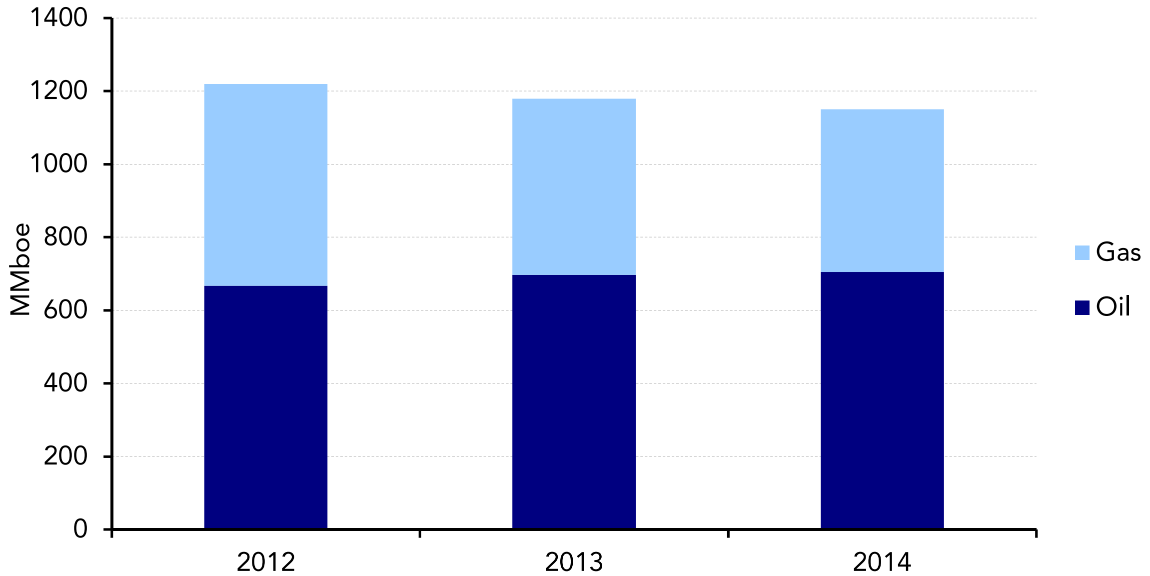


(1) Includes North Sea, Norwegian Barents and Greenland
(2) Includes Algeria, Egypt, Libya and Morocco
(3) Includes Australia, China and Indonesia

Source: BP estimates, excluding Rosneft

BP's total oil and gas production was 1,150 MMboe in 2014, down around 6% from the 2012 figure, as shown in the figure below. This reduction was mainly due to expiry of a concession in Abu Dhabi, as well as the divestment programme, although declines were partially offset by increased production elsewhere (including BP's stake in Rosneft).

Figure K-4 BP Oil & Gas Production[1]
(source: BP Annual Report 2014)

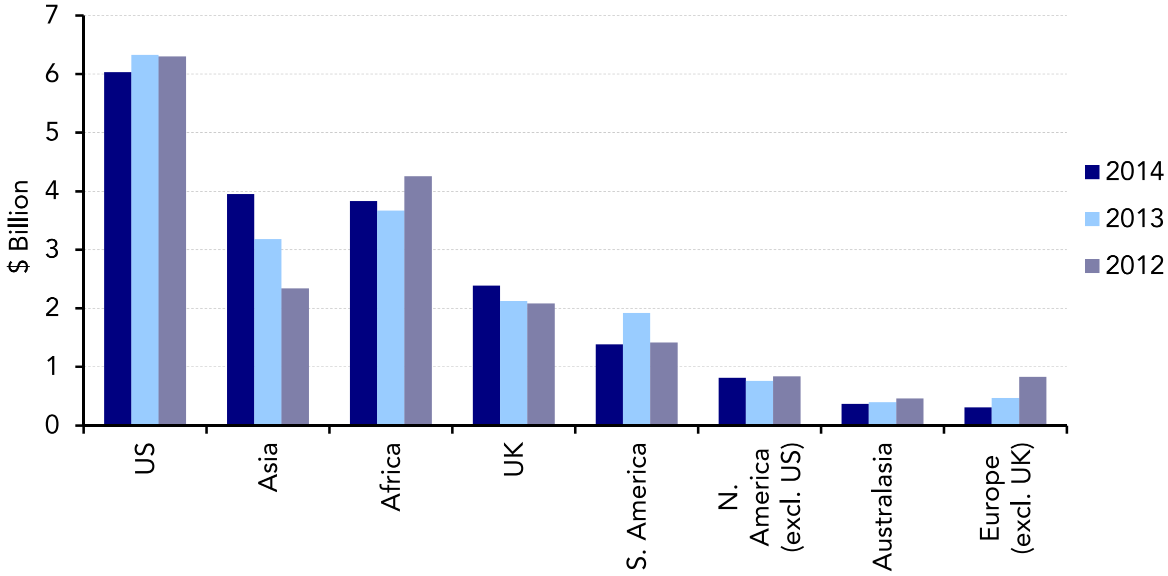


[1] Oil includes Crude Oil, NGL, and condensates

Investment

BP's costs incurred for exploration and production were around $19 billion in 2014, a breakdown of which is shown in the figure below. Capital investment in 2015 is expected to decrease, largely reflecting the lower oil price environment and BP's commitment to continued capital discipline. The reduction is expected to come primarily from prioritising activity in operations, paring back exploration, and shelving a number of marginal projects.

Figure K-2 BP Upstream Capital Expenditure by Country
(source: BP Annual Report 2014)



C.1.2 BG

C.1.2.1 Strategy

BG's aim is to become a world-leading E&P and LNG company, and it plans to focus on a portfolio of 10-15 quality assets and areas where it has competitive advantages. The company wants to leverage its current position in existing hubs such as T&T, Thailand, the UK North Sea, Australia, the USA, Bolivia, and Egypt, with existing infrastructure, knowledge of local geology and relationships with governments and key stakeholders. On the other hand, BG's strategy in new basins such as Brazil (Barreirinhas), Uruguay, Kenya and Honduras is targeting low cost, early entry and new giant discoveries. This strategy has led to consistent positive results, with 15 giant discoveries in 15 years. In 2014, BG had successful appraisal activity in Brazil and entered four new basins.

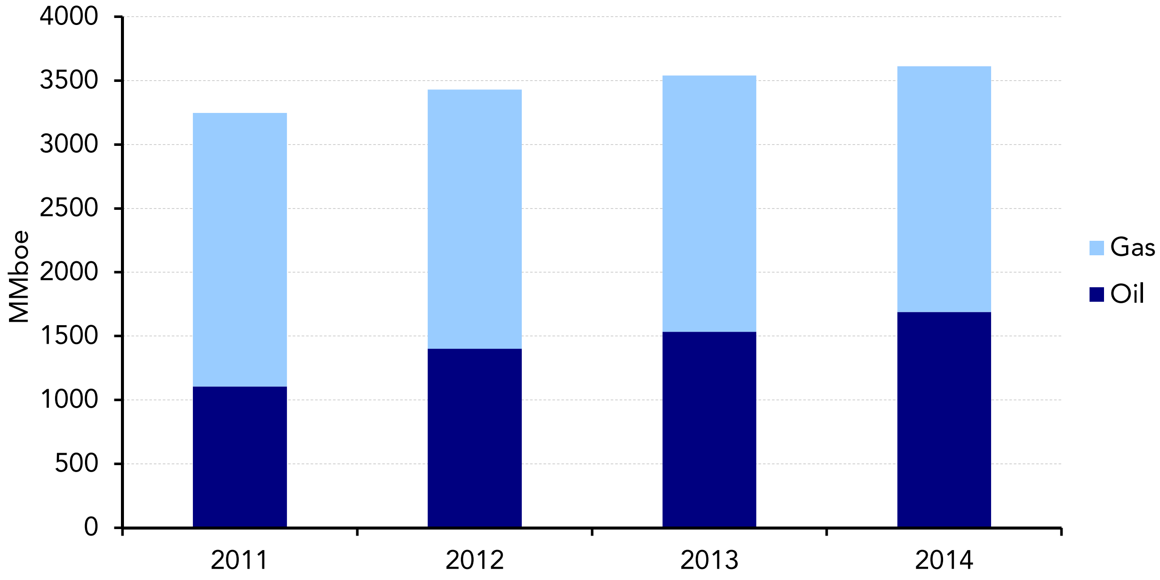
Australia and Brazil are key growth areas for BG. In Australia, BG is developing the 8.5 MMt/y Queensland Curtis LNG (QCLNG) project which is being supplied by coal seam gas and involved $20.4 billion of investment from 2011 to 2014. Brazil is a strategically important country in the company's portfolio, providing significant reserves of oil and gas. BG participates in five large pre-salt discoveries in the Santos Basin and participates as an operator in 10 blocks in the Barreirinhas Basin. BG has invested more than $8 billion in Brazil's oil and gas sector since 1994.

C.1.2.2 Activity

Reserves & Production

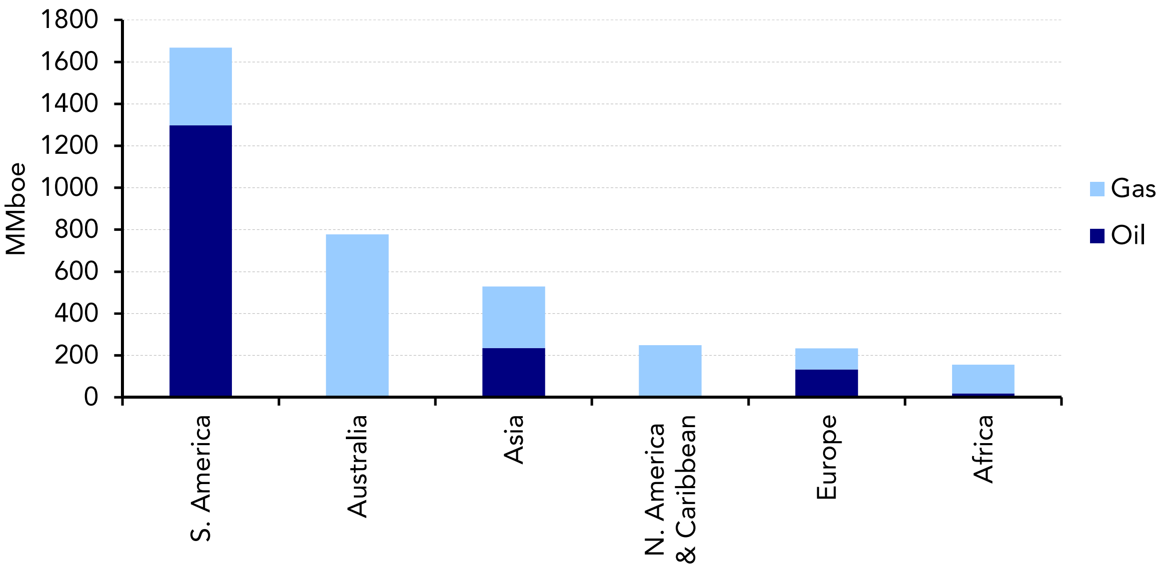
As of the end of 2014, BG's total proved reserves of oil and gas stood at 3,613 MMboe, of which around 53% was gas and 47% oil, as shown in the figure overleaf.

Figure K-7 BG Total Proved Oil & Gas Reserves
(source: BG Annual Report 2014)



The importance of Brazil and Australia to BG's portfolio are shown in the figure below which breaks down reserves by region. As of the end of 2014 South American reserves stood at 1,668 MMboe, of which oil accounted for 78%, while Australia reserves, which are 100% gas, stood at 778 MMboe.

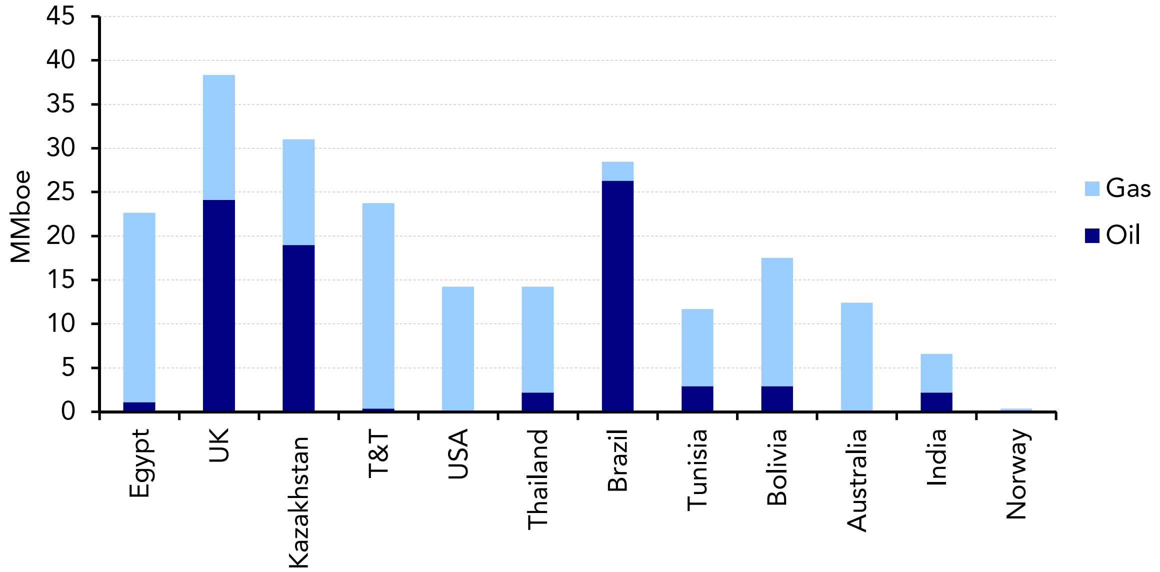
Figure K-16 BG Proved Oil & Gas Reserves by Country (2014)
(source: BG Annual Report 2014)



BG produced 221 MMboe of oil and gas in 2014. Around 63% of its production was gas, and gas accounts for the majority of production in most of regions except the UK, Kazakhstan and Brazil, as shown in the figure below.

Figure K-8 BG Oil & Gas Production by Country (2014)[2]

(source: BG Annual Report 2014)

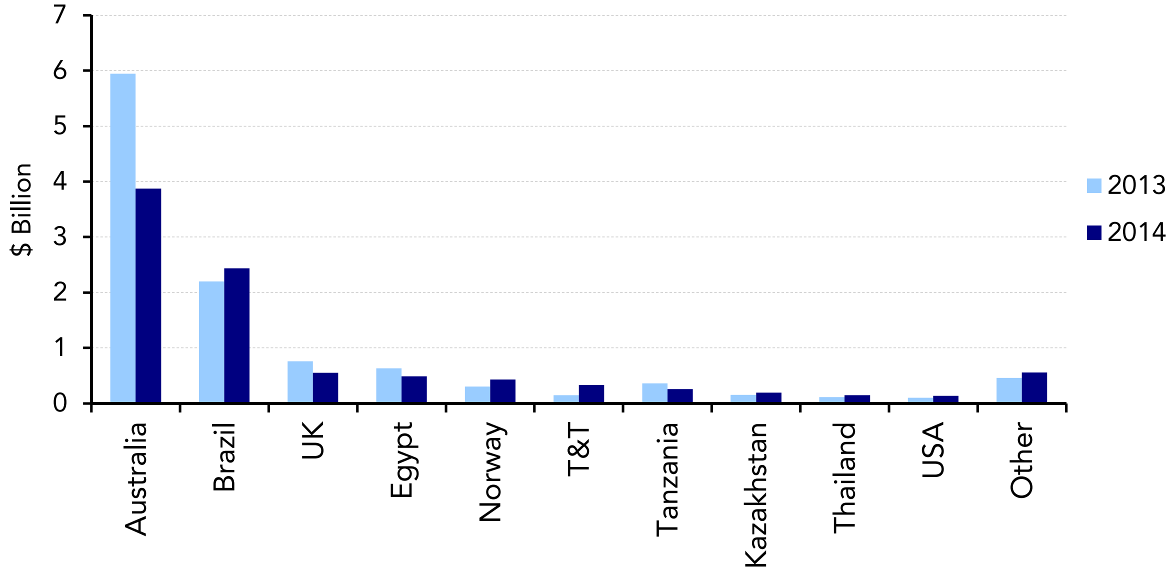


Investment

Capital investment on exploration and development in 2014 was $9.4 billion, representing a decrease of around $1.8 billion from 2013 largely due to a decline in LNG-related upstream expenditure in Australia, as shown in the figure overleaf.

[2] Oil includes Crude Oil, NGL, and condensates

Figure K-6 BG Upstream Capital Expenditure by Country
(source: BG Annual Report 2014)



New developments have consistently increased BG's unit costs of E&P, which increased from $45.4/boe in 2011 to $52.7/boe in 2014.

C.1.3 BHP

C.1.3.1 Strategy

BHP Billiton has exploration, development, production and marketing activities in more than ten countries, with a significant position in the deepwater in the US and Australia. The company is prioritising its significant and longer-term unconventional gas plays and targeting exploration program pursuing conventional oil opportunities.

Australia and the Gulf of Mexico are BHP's core regions with valuable infrastructure in place. The company plans capital expenditures of $1.5 billion per year to maintain stable production volumes for the next 3 to 5 years.

C.1.3.2 Activity

Reserves & Production

As of 2014 BHP's proved reserves of oil and gas were 2,443 MMboe, of which gas accounted for 65%, as shown in the figure overleaf. BHP's reserves position is dominated by the USA (63% of the total) and to a lesser extent Australia (33% of the total). The remainder, including T&T, makes up only 4% of BHP's total reserves position. BHP has a strong focus on deepwater exploration in the USA and Australia.

Figure K-10 BHP Total Proved Oil & Gas Reserves
(source: BHP Annual Report 2014)

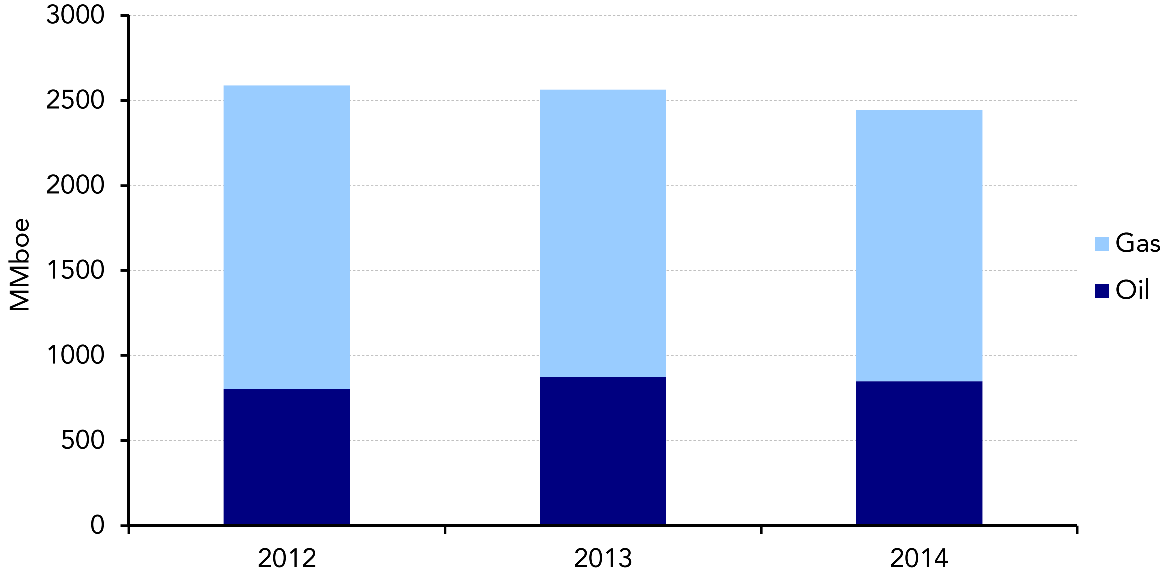
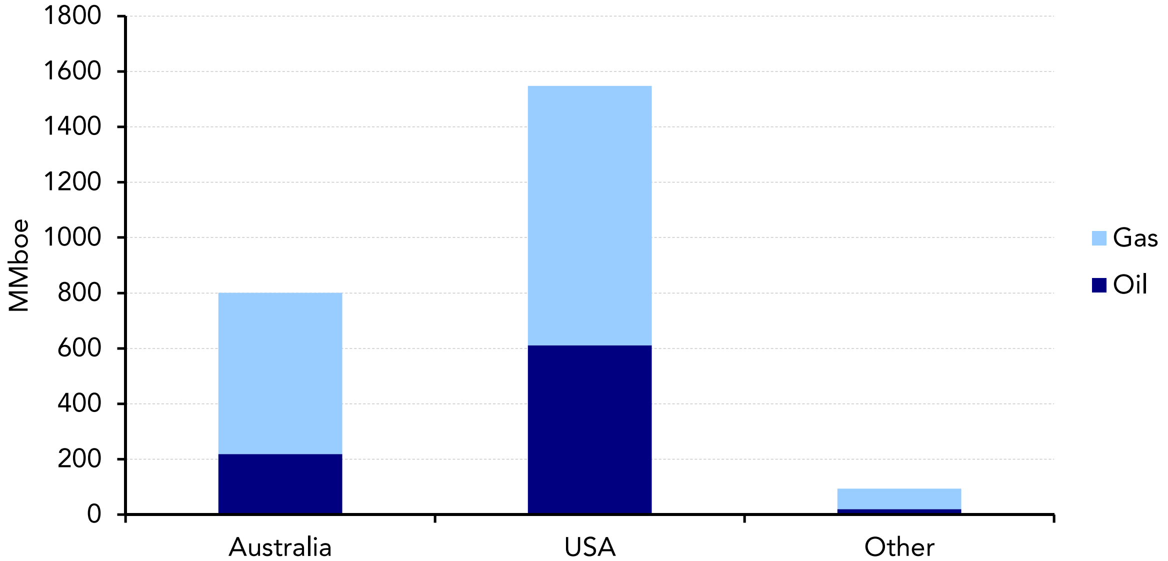


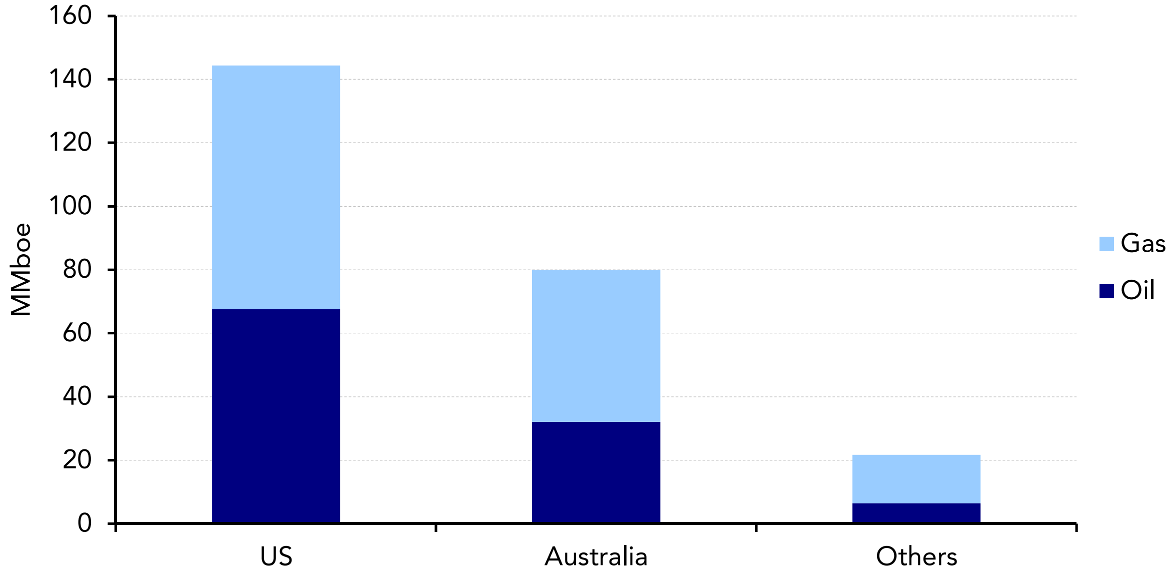
Figure K-16 BHP Proved Oil & Gas Reserves by Country (2014)[3]
(source: BHP Annual Report 2014)



BHP's production in 2014 was 246 MMboe, out of which gas accounted for 57%. As per the reserves position, production was dominated by the USA and Australia, as shown in the figure overleaf.

[3] Other: Algeria, Pakistan, Trinidad and Tobago, and the United Kingdom

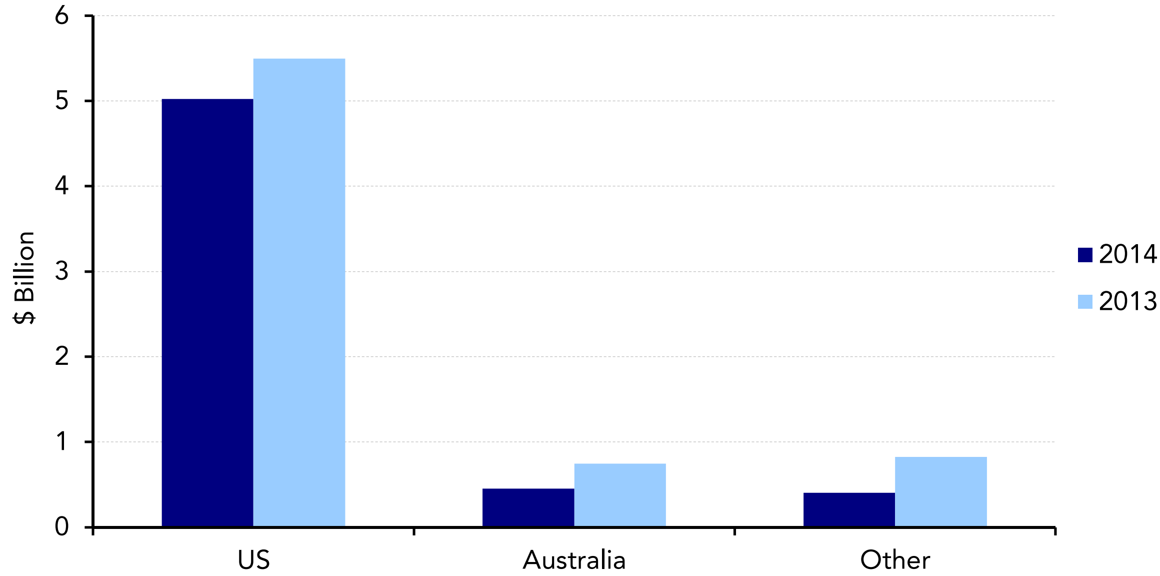
Figure K-11 BHP Oil & Gas Production by Country (2014)[4]
(source: BHP Annual Report 2014)



Investment

BHP's upstream investment in 2014 totalled $5.9 billion, the bulk of which ($5 billion) was in the US. This represented a slight decline from a total of $7.1 billion in 2013, as shown in the figure below.

Figure K-9 BHP Upstream Capital Expenditure by Country
(source: BHP Annual Report 2014)



[4] Other: Algeria, Pakistan, T&T, and the UK

C.1.4 EOG

C.1.4.1 Strategy

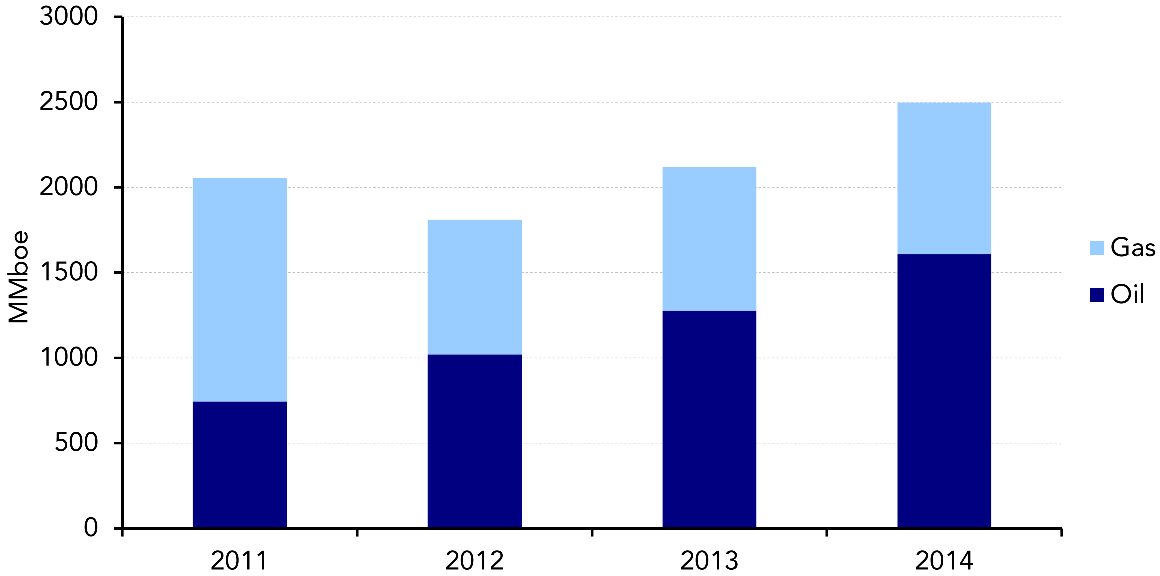
EOG focuses its business in North America, especially the US. Its 2015 strategy is to drill its best plays in the Eagle Ford, Delaware and Bakken plays, as it plans to spend about 80% of its capital expenditure in these areas. One of EOG's goals in 2015 is to reduce its costs and improve well productivity.

C.1.4.2 Activity

Reserves & Production

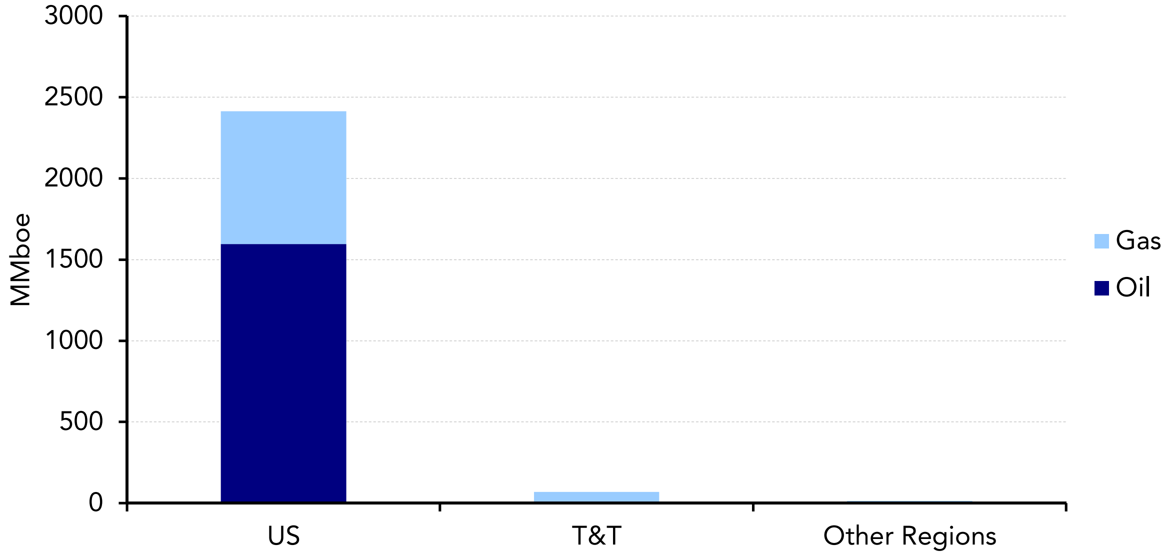
As shown in the figure below, EOG's proved reserves were 2,497 MMBoe as of the end of 2014, of which oil accounted for around 64%.

Figure K-13 EOG Total Proved Oil & Gas Reserves
(source: EOG Annual Report 2014)



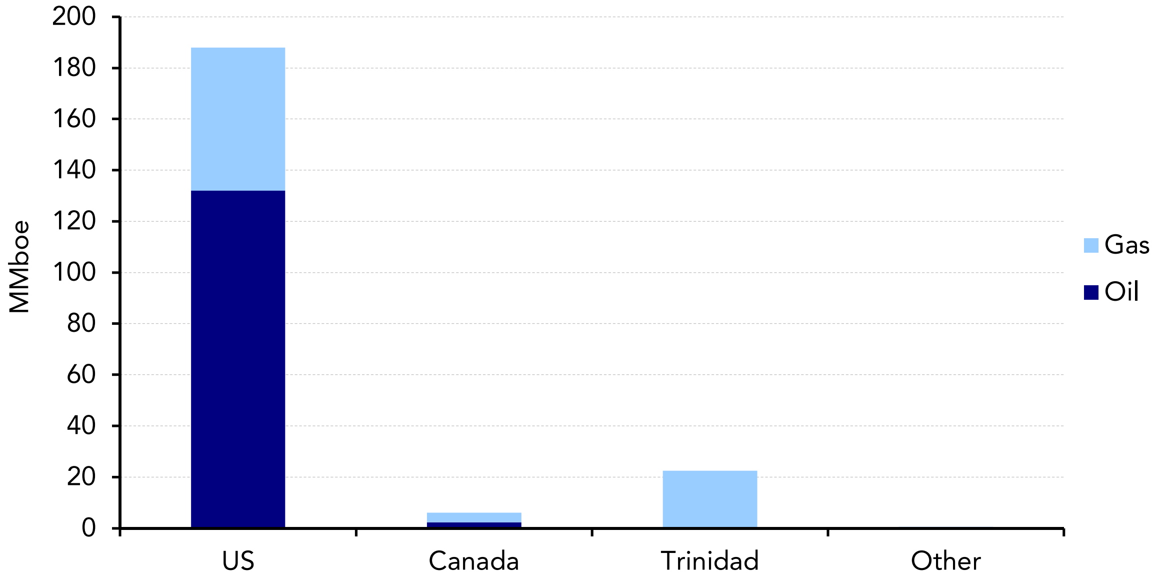
96.7% of total oil and gas reserves were located in the US, 2.8% in T&T and 0.6% in other locations, as shown in the figure overleaf.

Figure K-16 EOG Proved Oil & Gas Reserves by Country (2014)
(source: EOG Annual Report 2014)



EOG's production in 2014 was 217 MMBoe, and gas accounted for around 38%. Approximately 87% of EOG's 2014 production was in the US, as shown in the figure below. T&T contributed around 10% to EOG's total oil and gas production and around 27% to total gas production.

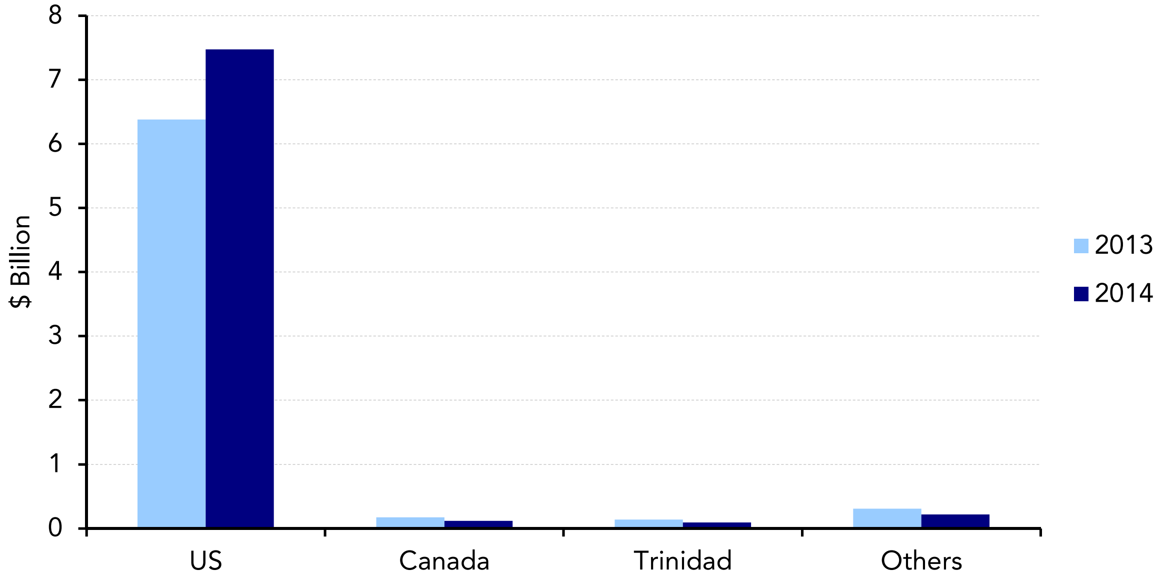
Figure K-14 EOG Oil & Gas Production by Country (2014)
(source: EOG Annual Report 2014)



Investment

EOG's upstream capital investment came to $ 7.9 billion for in 2014, although it is expected that this figure will reduce by around 42% to $4.6 billion in 2015. As shown in the figure below, around 95% of EOG's investment in 2014 came in the US.

Figure K-12 EOG Upstream Capital Expenditure by Country
(source: EOG Annual Report 2014)



C.1.5 Repsol

C.1.5.1 Strategy

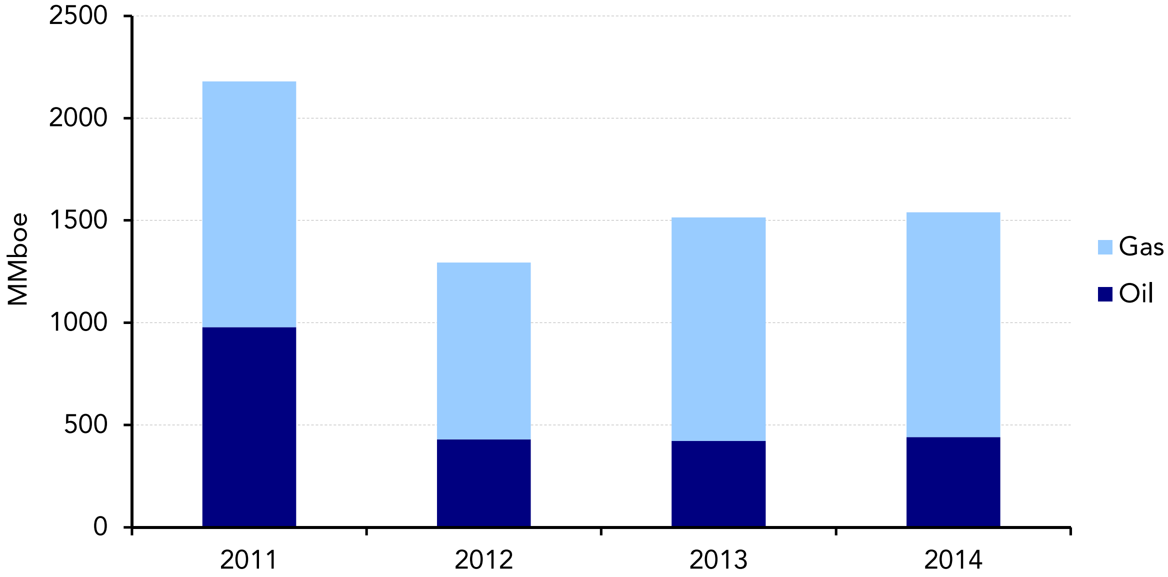
Repsol considers upstream as a growth engine for the company and plans to increase investments in the sector. Repsol's 2012-2016 Strategy Plan shows that the company expects to spend more than $1billion per year in exploration activities with the objective of adding 200-250 MMboe to its proven reserves annually. Repsol plans to invest 50% of total exploration investment in core areas the Gulf of Mexico, Brazil, Northern Latin America and North Africa, and it wants more/higher exposure to OECD countries. The company is actively divesting to fund its activity, including the sale of its LNG assets to Shell for $4.4 billion in 2013.

C.1.5.2 Activity

Reserves & Production

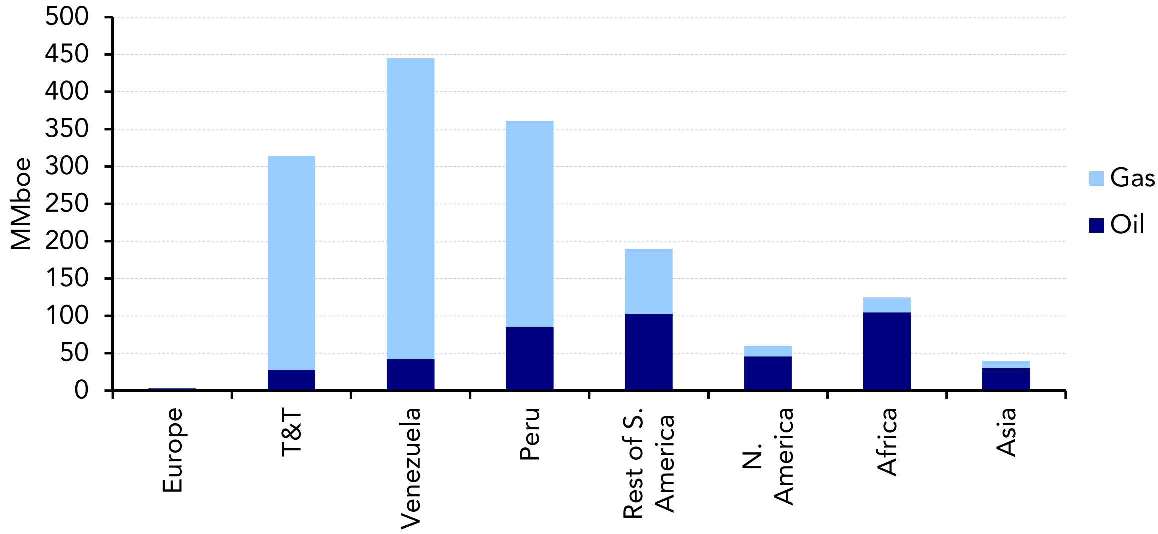
As of December 2014, Repsol's proved reserves of oil and gas were 1,539 MMboe, of which gas accounted for 71%. Its reserves have decreased from 2,180 MMboe in 2011, as shown in the figure overleaf, following the nationalisation of YPF in Argentina.

Figure K-16 Repsol Total Proved Oil & Gas Reserves
(source: Repsol Annual Report 2014)



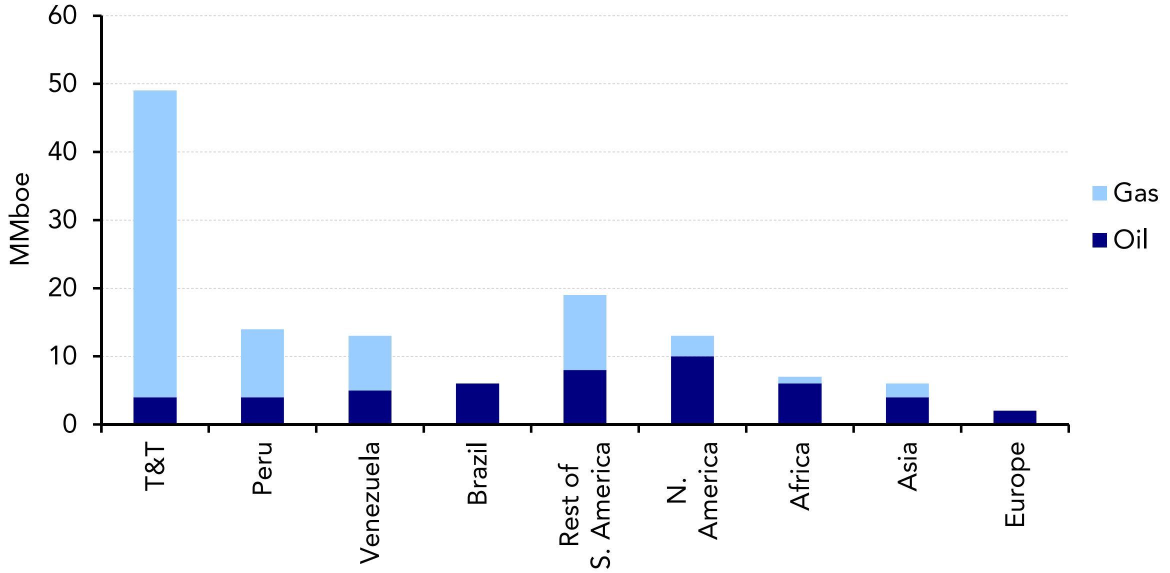
Latin America accounts for around 65% of Repsol's oil and gas reserves, followed by T&T on 20%. Venezuela, T&T and Peru dominate Repsol's gas reserves position, as shown in the figure below.

Figure K-16 Repsol Proved Oil & Gas Reserves by Country/Region (2014)
(source: Repsol Annual Report 2014)



Repsol's production in 2014 was 129 MMboe of which 80 MMboe was natural gas. T&T was by far the largest source, accounting for around 38% of total oil and gas production and around 56% of total gas production, as shown in the figure overleaf.

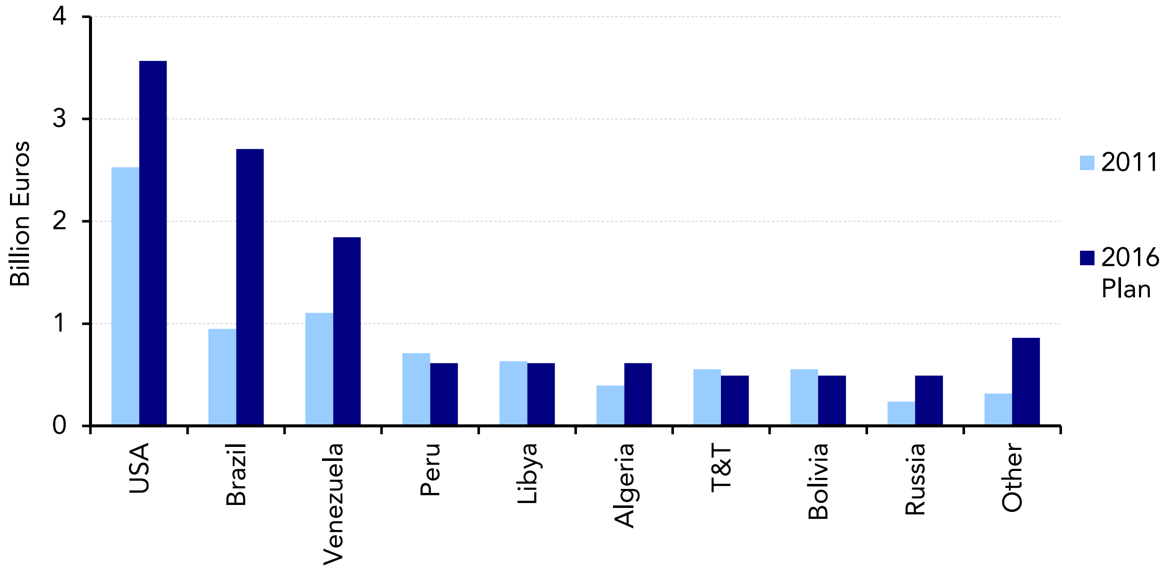
Figure K-17 Repsol Oil & Gas Production by Country/Region (2014)
(source: Repsol Annual Report 2014)



Investment

As shown below, Repsol's 201 Strategic Plan calls for upstream expenditure to reach around $12 billion in 2016, up from around $8 billion in 2011. The US is expected to attract the largest share of Repsol's investment in 2016 (29%), followed by Brazil (22%) and Venezuela (15%). Investment in T&T is projected to account for 4% of the global total.

Figure K-15 Repsol Upstream Capital Expenditure by Country
(source: Repsol 2016 Strategic Plan)

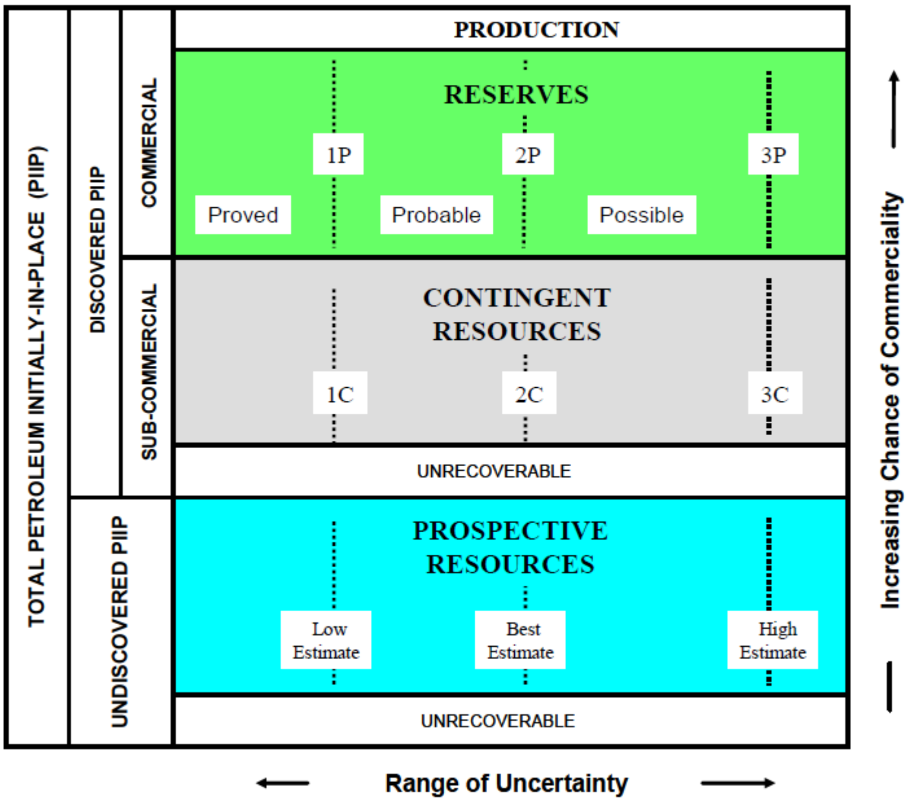


D.1 SPE PRMS RESERVES AND RESOURCES

Petroleum reserves and resources are classified by the Petroleum Resources Management System (PRMS) developed by the Society of Petroleum Engineers (SPE), American Association of Petroleum Geologists, The World Petroleum Council and the Society of Petroleum Evaluation Engineers. The classification for discovered petroleum reflects the level of confidence in a volumetric estimate through a number between 1 and 3 and the chance of commercialisation through a letter P or C.

Figure D-1 SPE PRMS Reserves and Resources Classification

(source: SPE)



Before discovery all resources are classified as "Prospective". Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be sub-classified based on project maturity.

Discovered resources are initially classified as "Contingent" before their development has been assessed. Contingent Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations, but the applied project(s) are not yet considered mature enough for commercial development due to one or more contingencies. Contingent Resources may include, for example, projects for which there are currently no viable markets, or where commercial recovery is dependent on technology under development, or where evaluation of the accumulation is insufficient to clearly assess commerciality. Contingent Resources are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by their economic status.

The term "Reserves" refers to petroleum which is anticipated to be commercially recoverable. Reserves are those quantities of petroleum anticipated to be commercially recoverable by application of development projects to known accumulations from a given date forward under defined conditions. For a new development typical conditions would be plans to sanction the project within a reasonable timeframe (typically five years) based on an expectation that the market, facilities and development approvals can be put in place. Reserves must further satisfy four criteria: they must be discovered, recoverable, commercial, and remaining (as of the evaluation date) based on the development project(s) applied. Reserves are further categorized in accordance with the level of certainty associated with the estimates and may be sub-classified based on project maturity and/or characterized by development and production status.

Uncertainty in volumes is represented by a number between 1 and 3 for discovered petroleum and Low/Best/High for prospective resources:

- 1P/1C/Low Estimate has a 90% probability of being exceeded by the actual recovered volume.
- 2P/2C/Best Estimate has a 50% probability of being exceeded by the actual recovered volume.
- 3P/3C/High Estimate has a 10% probability of being exceeded by the actual recovered volume .

The terms Proved, Probable and Possible Reserves are used to describe the incremental volumes added by an assessment that sequentially considered the 1P, 2P and 3P reserves of a development.

- Proved Reserves are those quantities of petroleum, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under defined economic conditions, operating methods, and government regulations. If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.
- Probable Reserves are those additional Reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than Proved Reserves but more certain to be recovered than Possible Reserves. It is equally likely that actual remaining quantities recovered will be greater than or less than the sum of the estimated Proved plus Probable Reserves (2P). In this context, when probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the 2P estimate.
- Possible Reserves are those additional reserves which analysis of geoscience and engineering data suggest are less likely to be recoverable than Probable Reserves. The total quantities ultimately recovered from the project have a low probability to exceed the sum of Proved plus Probable plus Possible (3P) Reserves, which is equivalent to the high estimate scenario. In this context, when probabilistic methods are used, there should be at least a 10% probability that the actual quantities recovered will equal or exceed the 3P estimate.

D.2 EXPECTED VALUES

The category of reserves describes the probability of a gas volume being produced from two perspectives. The classification of a gas volume as Reserves, Contingent Resources and Prospective Resources indicates the degree of certainty that the field will be developed while the numerical classification of 1, 2, 3 indicates the range in gas volumes that may be produced when that development occurs, being P90 (90% chance of at least this volume being produced), P50 (50% chance of at least this volume being produced) and P10 (10% chance of at least this volume being produced).

Care must be taken in interpreting the addition of reserves estimates from individual fields to understand the range of outcomes for a portfolio of fields. For instance, if the volumetric outcome of one field provides no guidance on the outcome of a second field (i.e. if the outcomes are independent) then the chance of both fields delivering a P10 result would be 10% x 10% = 1%. Thus adding together the P10 reserves estimates does not deliver a P10 for the portfolio of fields where their volumetric outcomes are independent. However if an outcome in one field provides strong evidence for a similar outcome in another field due to similarities in geology, seismic response etc. then summing P10 estimates will provide a reasonable estimate of the portfolio P10 outcome.

The mean or expected volumetric outcome of fields can always be summed to provide an estimate of the mean volume from a portfolio. The mean is often quoted in reserves assessments, but where it is not it can be calculated from the P10, P50, P90 volumes. For a symmetrical distribution the mean is equal to the P50 volume. For a mildly skewed distribution the mean can be estimated using Swanson's rule which states an estimate of the mean can be calculated as

$$1P \times 30\% + 2P \times 40\% + 3P \times 30\%$$

D.3 RISKING

Contingent and Prospective resources may be "risked" by multiplying the mean development volume by the chance of the development occurring. In the case of Prospective Resources this is dominated by the Probability of Success (PoS) of the exploration well targeting the prospect. A risked resource estimate does not represent an outcome for a specific field or prospect, but can be used as a measure of the expected overall outcome for a portfolio of prospects and fields, in which some fields are discovered and developed while others are not successful.

These principles are applied to the reserves information available for T&T in Section 7.

Appendix E Benchmark Country Competitiveness Initiatives

Many countries in the benchmark group have recently improved their oil & gas regulation, prices and overall attractiveness to investors. The most relevant examples of recent changes and their scope are summarised below to provide examples of the tools available to attract exploration and development investment.

E.1 INDONESIA: MARGINAL GAS FIELDS

E.1.1 Context

At a high level, the gas economy in Indonesia, although larger, has some similarity to the gas economy in T&T. However, production decline from plateau levels in the mature Indonesian basins is more pronounced than in T&T. About 10 years ago, after many years of being one of the world's largest LNG producers and a large scale producer of petrochemicals (ammonia, urea and methanol), production from Indonesia's mature gas basins began to decline. The government was slow to respond. Gradually, the government and local industry came to the realization that the cheap gas in Indonesia's mature basins had largely been developed and that government support was needed to continue meaningful development of the remaining, less economic, gas resources in these basins. This section describes Indonesia's support for development of marginal gas fields as part of the government's overall response to this declining production.

E.1.2 Forms of Government Support for Development of Marginal Fields

Marginal fields are defined in different ways by various host governments. However, the broad definition is a field that is not economic to develop without fiscal and other incentives beyond the standard terms offered by host governments.

In the case of Indonesia, varied support mechanisms, including fiscal incentives, are utilised to promote development of as many viable fields as possible. Government support is provided in a myriad of forms, from accelerated cost recovery for a single well to broader incentives for the costly and relatively small discoveries in deepwater East Kalimantan. The seemingly incomprehensible processes in Indonesia funnel gas development projects through a series of approvals that are intended to result in a government unofficial target of 15 to 20% IRR for the upstream investor. Rent is extracted throughout the processes if the government perceives that excess rent is available. Additional incentives are provided if the Government is satisfied that they are required to make the project economic. Although these processes work very slowly, and sometimes result in project delays, they do promote development of marginal gas fields if the development is economic on a gross basis.

E.1.2.1 Indonesian Law

The Indonesian Oil and Gas Law is general in scope and is intended to encourage oil and gas development. In many instances, implementation of the law has proven to be onerous. However, implementation of the law has been generally positive in regards to encouraging development of smaller oil and gas fields.

For example, all infrastructure assets that are part of an oil and gas development (as are the hydrocarbons) are owned by the government. The law manifests itself in PSC language that obligates a PSC operator to make available unutilised capacity in pipelines, plants and other facilities for use by other PSCs on the basis of shared operating costs, providing essentially open access to unutilised plant and facility capacity.

A significant portion of existing gas related infrastructure falls within this category, including some major pipelines, compression facilities and one of the LNG liquefaction plants. Rent taking by the PSC operator which originally built and cost recovered the infrastructure is not permitted. Although this policy seems unfair to the original investors in the infrastructure, the government's intent is to maximise revenue for the state by encouraging development of marginal fields that might otherwise not be able to bear the cost of expensive infrastructure.

E.1.2.2 PSC Fiscal Terms

Indonesia currently has two forms of PSCs, conventional oil and gas and coal-bed methane (CBM) and has considered adding new PSC forms to promote oil & gas development. The government adjusts PSC fiscal terms from time to time based on the perceived quality of the acreage being offered for bid. Fiscal terms include First Tranche Petroleum (FTP) which is allocated to the government off the top and is typically 10%, a cost recovery cap which varies and an after tax profit split that varies. Ring fencing of discoveries in producing PSC's for purposes of cost recovery is included in the current form PSC.

The "open access" provision discussed above is included in all PSCs. The standard oil and gas PSC also contains provisions for accelerated cost recovery for fields with a short depletion life. Other terms are fairly standard.

Work program and bonus are typically the only terms open for bid.

E.1.2.3 Gas Allocation

All gas and LNG sales in Indonesia must be approved by the government in the form of two approvals: 1) gas allocation and 2) price. Gas allocation approval pegs a specific tranche of production from a PSC to a specific sales contract and acts as a tool for the government to preferentially allocate artificially low priced markets, such as petrochemicals and power, to producers that it perceives can bear the lower prices and higher priced markets like LNG to projects that it perceives require premium prices to be economically viable. The deepwater developments in Indonesia would be a good example of projects that the government has perceived as requiring access to the premium markets.

E.1.2.4 Plan of Development Approval

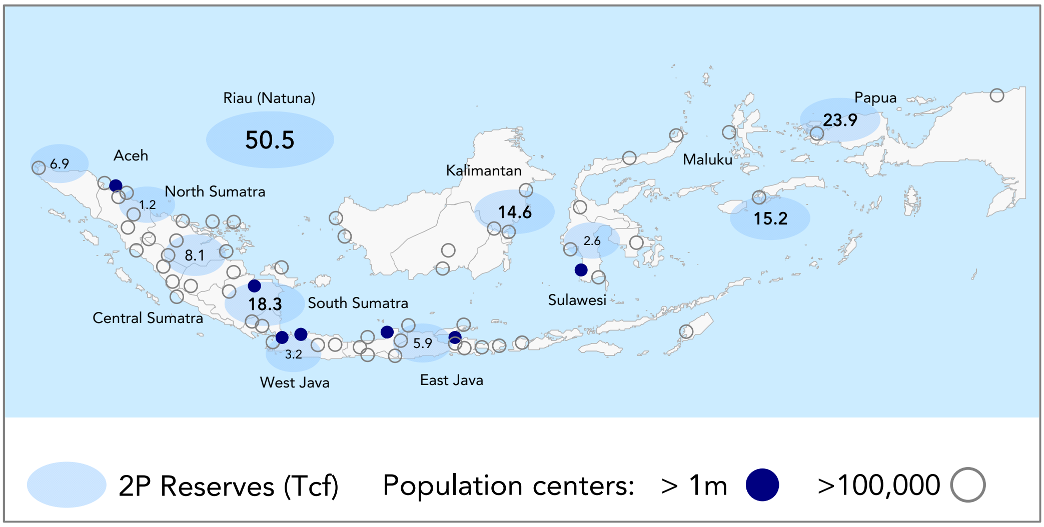
If the various forms of government incentives discussed above are insufficient to support development of a marginal gas field, the Plan of Development (POD) approval process can be a source of additional incentives.

The regulations define a straightforward POD approval process, whereby the POD is reviewed and approved on the technical, cost and economic merits of the project. However, by custom, a process has developed for gas development projects whereby the government, represented by SKKMIGAS (the gas sector regulator), negotiates terms for approval of the POD for gas projects. By mutual consent, even some PSC fiscal terms can be adjusted or waived during the negotiation of the POD. This approval has evolved to become the key decision for many gas development projects.

E.1.3 Key Success Factors and Lessons Learnt from Indonesia's Marginal Fields

The Indonesian gas industry is mature in East Kalimantan, North Sumatra and Java, with gas production in decline in each area. Gas production is Papua is growing following the start-up and planned expansion of the Tangguh LNG plant.

Figure E-1 Indonesia's 2P Gas Reserves in 2013
(source: MoEMR)



Gas development in East Kalimantan most closely resembles T&T, although East Kalimantan gas development is in a more mature stage. Many of the issues now facing T&T were experienced in East Kalimantan and the success factors and learnings captured in this section and are based primarily on Indonesia's experience in that region.

The East Kalimantan gas industry is comprised of the following:

- Very mature gas production from offshore shallow water and onshore fields.
- Relatively small deepwater gas discoveries in development, with continued exploration.
- Bontang LNG Plant consisting of 8 trains, with 2+ trains currently idle.
- Syngas based petrochemical estate with a combined gas feed of about 500 MMcf/d to ammonia, urea and methanol.
- Power generation.
- Centralised gas compression offshore and onshore.
- Gas transmission pipelines (East Kalimantan Gas System).

Although all gas infrastructure in East Kalimantan is owned by the government, which in theory provides open access to new entrants, the heritage players remain actively involved in the East Kalimantan gas system and Bontang LNG plant through a set of commercial arrangements that had grown over decades of development. Bontang LNG is owned by the government and is assigned to Pertamina to manage. The operator of Bontang LNG, PT Badak, is owned by Pertamina, VICO (a BP/ENI joint venture), Total and a consortium of Japanese LNG buyers. The East Kalimantan gas system is owned by the government, but operated and managed by VICO onshore and Total offshore. The petrochemical plants are 100% state-owned enterprises, except methanol.

Figure E-2 Bontang LNG Plant in East Kalimantan

The majority of the onshore gas production in East Kalimantan now comes from marginal fields. A small but growing percentage of shallow water gas production in East Kalimantan comes from marginal fields. All of the currently deepwater offshore discovered resources are marginal gas fields, but exploration continues.

E.1.3.1 Key Success Factors

Strengths

- Indonesian law is well designed to promote development of the nation's hydrocarbon resources.
- Government's willingness to adjust fiscal terms in the form PSC over time works to promote exploration.
- Government willingness to be flexible on fiscal and commercial terms for marginal gas fields works to assure that discovered gas, if economically viable, is developed.
- The relatively open access to unutilised gas and LNG infrastructure in East Kalimantan has been, and continues to be, a key draw for continued exploration and development in East Kalimantan.

Weaknesses

- The Indonesian Government bureaucracy is massive and slow to act.
- The complexity of dealing with multiple government entities responsible for oil and gas (Ministry of Energy and Mineral Resources, MIGAS, SKKMIGAS and Pertamina) creates confusion and significantly slows approval processes.
- Complexity in government approval processes results in delays to many projects and is a barrier to getting projects sanctioned.
- The government's practice to extract additional rent from gas projects, when available, may also dampen appetite for continued exploration and development.

- Pertamina, a state-owned company, has been seeking to gain a larger place in the industry. For example, Pertamina is hoping to extract rent at Bontang LNG and may dampen appetite for continued development in East Kalimantan.
- Non-aligned commercial interests in East Kalimantan has slowed the pace of access of new entrants into the system, as the incumbents have little or no incentive to dedicated time and manpower to facilitating new entrants.
- A growing nationalist sentiment in Indonesia may act to deter foreign investments in the future.

E.1.3.2 Lessons Learned

- Despite the weaknesses below, most of the larger multinational E&P companies remain active in Indonesia.
- Fiscal incentives alone were not sufficient to assure development of the marginal gas fields in East Kalimantan. Access to infrastructure and premium LNG markets was needed.
- A measured approach to rent taking is needed from government to allow development of marginal fields.
- Active government support in a visible way is needed to create the needed confidence for foreign companies to continue to invest in exploration and development of marginal resources in mature basins.
- Continued exploration in East Kalimantan is largely driven by proximity to the East Kalimantan gas system and Bontang LNG.
- Artificially low gas prices to state-owned power and petrochemicals are too low to justify continued development in East Kalimantan, either traditional or deep water.
- Development of marginal fields in East Kalimantan has been successful, accounting for a growing percentage of gas production.

E.2 ARGENTINA: GAS PRICE AND HYDROCARBON LAW REFORM

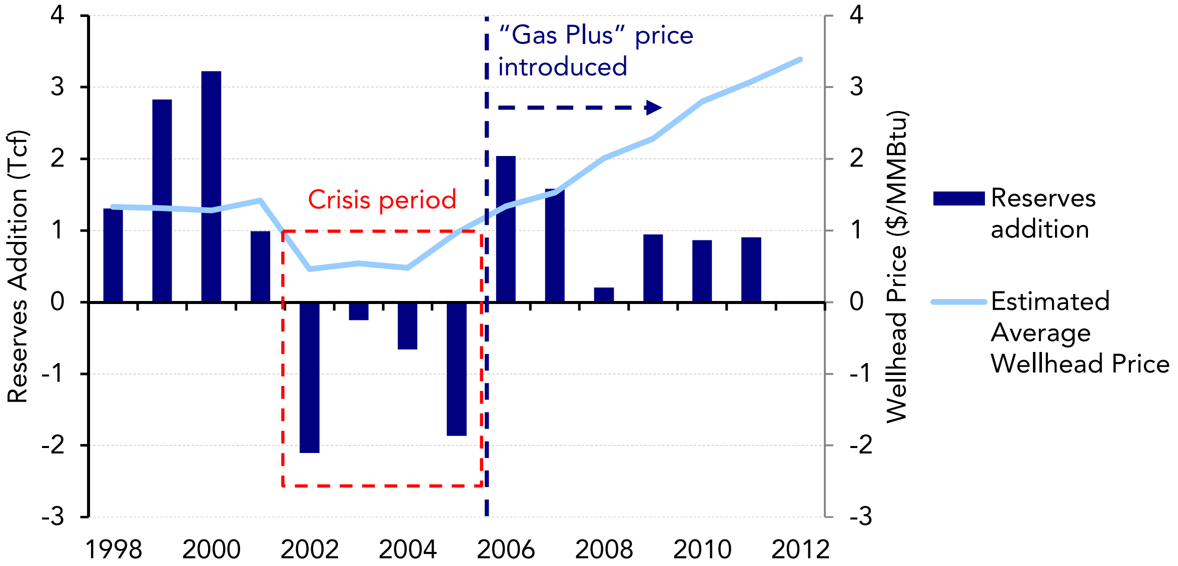
In the early 2000s, Argentina's upstream sector struggled with an extremely low wellhead prices ($0.5/MMBtu). The situation reached its worst during Argentina's economic crisis in 2001-2 when gas exports to Chile were stopped (Chile subsequently developed alternative imports, including LNG receiving terminals). In order to remedy the situation, the government introduced the "Gas Plus" regulation in 2006. It required regular increases to the average wellhead price which eventually reached circa $3.3/MMBtu in 2012 up from $0.5/MMBtu in 2004. The price reached in 2012 was still lower than prices required for conventional gas production, which were estimated at $4.5/MMBtu. Nonetheless, the price increases had already had a positive impact on gas exploration, as highlighted in the figure below, which depicts the gas reserve additions and the average gas price over the period 2000-2012 in Argentina.

The "Gas Plus" program continued and the gas price in Argentina was subsequently increased to $5.00/MMBtu in 2013 and to a regional high of $7.50/MMBtu in October 2014.

The end user gas price is still heavily subsidised in Argentina (residential: ~$2/MMBtu; industrial: ~$3.5/MMBtu) and therefore the government, which guarantees the $7.5/MMBtu to the producers, carries a significant burden on its state budget to finance the price differential. Without end-user price reform the sustainability of the "Gas Plus" program is therefore questionable.

Argentina also passed a new hydrocarbon bill designed to boost investment in Argentina's vast shale deposits with the end goal of reducing the country's reliance on energy imports. The cash-strapped country has become more responsive to the need to attract hard currency, driven especially by the need to raise an estimated $200 billion to develop the Vaca Muerta shales over the next 10 years according to YPF.

Figure E-3 Gas Reserve Increments and Gas Prices in Argentina
(sources: BP, IEA)



There are now nationwide rules for royalties and concessions, providing greater certainty for investors. The new legislation modifies the almost five decade old law (1967) that was ill-suited to encourage unconventional production of hydrocarbons. The measures aim to address investors' fears about an administration that gained notoriety for renationalising YPF, formerly controlled by Spain's Repsol. The main modifications introduced are the following:

- Extended concession lengths to 25 years for conventional resources, 30 years for offshore and 35 years for unconventional.
- Exploration periods are set at six years for conventional blocks and eight years for unconventional.
- Capping of the national royalties at 12% through an initial concession, with a maximum of a 3% increase on unlimited 10-year renewals.
- Offshore, heavy oil and tertiary recovery projects are incentivised with up to a 50% cut in royalties.
- Any company that invests $250 million can sell a portion of its oil abroad free of export taxes after the third year, that amount is capped at 20% for unconventional and 60% for offshore production.

Nonetheless, the new legislation does not address yet one of the country's most important energy problems which is the heavily subsidised end-user prices.

E.3 UK: REDUCING TAX BURDENS, OPENING INFRASTRUCTURE ACCESS

E.3.1 Taxation

On 20th March 2015, the UK Chancellor of the Exchequer responded to a long-running campaign by the oil and gas industry and introduced tax cuts worth $1.9 billion to support the mature UK North Sea oil and gas sector as it struggled to cope with higher costs and low oil prices. The scope of the changes introduced covered the following:

- Reduction in the supplementary charge on oil and gas production from 30% to 20%, taking the headline rate of tax to 50%, when 30% corporation tax rate is taken into account. Backdated to January 2015, the move builds on a 2% cut announced in December 2014, and reverses in full the 12% point increase in the supplementary charge announced in 2011.
- Reduction of the Petroleum Revenue Tax (PRT), the levy paid on the North Sea's oldest fields, from 50% to 35% from 2016, resulting in a headline rate for PRT-paying fields of 67.5%. The PRT rate reduction is an additional boost for the most mature North Sea fields, which have been taxed at a marginal rate of 81% previously.
- Investment allowance to reduce the effective tax rate for new investment.
- UK government to fund $30 million of new seismic surveys.

E.3.2 Infrastructure Access

Access for developers of offshore oil and gas fields to upstream infrastructure for the purpose of transporting and processing hydrocarbons is a key element in maximising the exploitation of the UK's oil and gas resources. The third party access regime has a voluntary, industry-led component, but this is underpinned by a statutory regime. The Code of Practice on Access to Upstream Oil and Gas Infrastructure on the UKCS (ICoP) was launched in 2004, and revised and updated in 2012. Its goal is to open up access to infrastructure on the UKCS for new and smaller users so that small adjacent fields can be made economically viable. It provides a framework for oil and gas infrastructure owners and users of the process that must be followed in seeking, offering and negotiating access to oil and gas infrastructure on the UKCS.

The ICoP applies to:

- Onshore oil and gas terminals and pipelines that handle oil up to the point at which it has been stabilised.
- Gas prior to the point at which it enters into the National Transmission System.

The ICoP is intended to clarify, streamline and facilitate the timely resolution of access requests on a negotiated, non-discriminatory basis. The ICoP is voluntary and is not legally binding. However, DECC encourages parties to follow the ICoP and if DECC becomes involved in a dispute about third party access (*see below*), then one of the many factors it considers is whether the parties have followed the ICoP.

Owners of upstream infrastructure must publish their main commercial conditions for access annually. Third parties wishing to obtain access to such facilities negotiate in good faith directly with the owners in the first instance on the basis of these published commercial terms. Where a party that seeks access to upstream oil and gas infrastructure cannot agree rights of access with the owner, it has the right to apply to the Secretary of State for a notice granting the relevant rights. The Secretary of State will consider such an application only if he believes the:

- Parties have had reasonable time in which to reach an agreement.
- Granting of the rights will not prejudice the:
  - transportation or processing of quantities of petroleum that the infrastructure owner could reasonably be expected to require; or
  - rights of other third parties with respect to the infrastructure.

If the Secretary of State decides to accept the application and issues a third party access notice, this notice may be subject to various conditions, including any conditions the Secretary of State considers appropriate to ensure that no person suffers a loss due to the mixing together of substances being transported or processed using the relevant facility. Importantly, the Secretary of State can issue an access notice under his own initiative, where parties have had reasonable time in which to reach an agreement and there is no realistic prospect of an agreement being reached.

A similar regime under the Gas Act 1995 applies to downstream gas processing facilities (for example, facilities that process gas for the purpose of the gas being put into storage, an LNG import or export facility, a gas interconnector or a distribution system pipeline).

E.4 EGYPT: PAYING DOWN DEBTS AND REFORMING GAS PRICING

Egypt's willingness to push fuel market reforms and stick to debt repayment plans has led to an unexpected resurgence in oil and gas exploration and supply deals previously delayed by political upheaval. The country has emerged as major new oil and gas development area as the government looks to ease the worst energy crunch in decades.

In early 2015, Egypt confirmed its plans to repay all of its $4.9 billion debt to foreign oil and gas companies within six months. The country previously delayed payments to oil and gas firms as its economy had suffered four years of instability since 2011. In addition to clearing its debt to the oil companies, Egypt has also stimulated upstream activity by giving explorers advantageous deals from waiving signature bonuses on new leases to tying payments to production increases. In January 2015 alone, Egypt signed 15 new exploration deals with energy companies such as Eni, BP, Shell and Total.

Egypt plans to import LNG, which will open up its domestic market to global energy pricing. The government has confirmed scrapping energy subsidies by 2019. The gas price received by offshore gas producers has more than doubled to $6.00/MMBtu for new developments, compared to the previously capped price of $2.65/MMBtu.

A direct result of these changes was a decision by BP to go ahead with a $12 billion investment in Egypt's offshore gas fields which represents a major vote of confidence for Egypt. The West Nile Delta project is expected to produce 1.2 Bcf/d (with gas reserves supporting the project of ~5 Tcf), equivalent to about 25% of Egypt's current gas production. BP and BG are also discussing joint use of gas pipeline infrastructure which is currently underutilised.

Eni has also recently announced a $5 billion investment for the next 4 years in Egypt, which will fund projects to develop 1.3 Tcf of gas and 200 Mbbl of oil. Eni confirmed that the revised gas price, as well as extensions of some permits, was necessary to ensure adequate levels of profitability.

E.5 MEXICO: OPENINGS TO PRIVATE SECTOR ATTRACTING GLOBAL ATTENTION

Mexico has opened its energy industry up to private investment for the first time in 76 years. Reform plans were unveiled in August 2013 and approved during the summer 2014 amending articles 25, 27 and 28 of the Mexican constitution:

- Article 25 – Petróleos Mexicanos (Pemex) to become a state productive enterprise.
- Article 27 – The State may contract with private parties for exploration and production of hydrocarbons allowing entrance of new technologies for the development of resources.
- Article 28 – Removes midstream and downstream industries from state control.

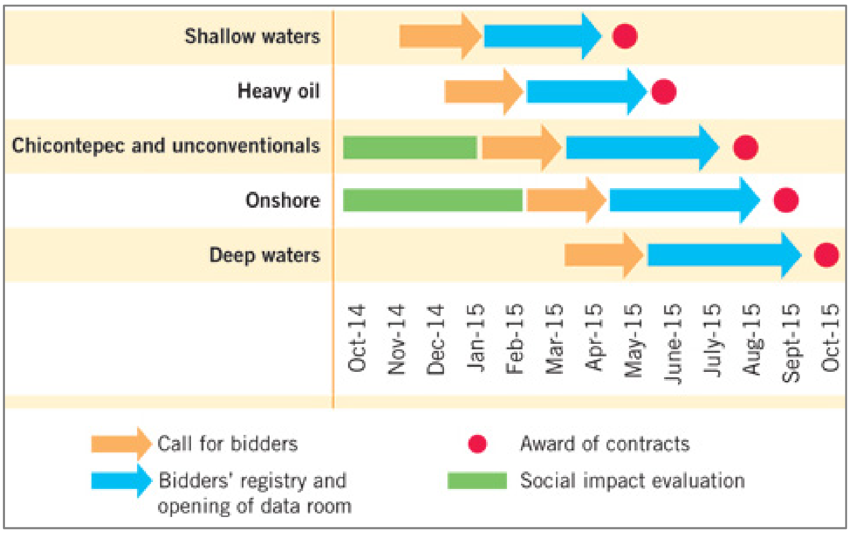
The Pemex monopoly on natural gas exploration is now broken. The opening of Mexico's energy industry is forecast to bring in $50 billion in investment by 2018.

A bidding process for new acreage has also started. The figure below describes the schedule of rounds contemplated by Mexico in late 2014. The first step was for Pemex to retain its preferred acreage. Mexico has assigned the majority of known reserves to Pemex in a non-competitive bid round held in August 2014. In this "Round Zero", Pemex was awarded 83% of the country's proven and probable reserves and 21% of prospective resources.

The Mexican government hosted road shows in Houston, New York, and London for investment bankers, fund managers, and executives at international companies to promote the first bidding round and garner feedback on model contracts. The entire bidding process is due to offer 109 exploration blocks and 60 producing blocks. The blocks include areas in shallow and deep water, mature fields, and heavy oil fields in the Perdido and Chicontepec areas, the Tampico Misantla basin, and unconventional plays in the Sabinas basin. "Round One" focusing on shallow water acreage (14 Gulf of Mexico blocks) is currently in progress.

Figure E-4 Schedule for Mexican Exploration Rounds as of October 2014

(Source: CNH)



Since the invitation for bids was announced in December 2014, 38 companies (including ExxonMobil, Chevron, Shell, Ecopetrol, and BG) have expressed interest, and 26 of these companies have requested access to the data room, which houses seismic and geological data that has been the exclusive preserve of Pemex for nearly eight decades, for a $350,000 fee. The data room opened in January 2015. It is expected that up to 60 companies participate in all of the different rounds.

So far, no indication has been given of the expected profit oil levels in the shallow-water PSC (round one). Furthermore, full details of the other contract models are yet to be released. When discovered fields are offered, the government take is likely to be higher due to the lower risk. For deepwater areas later in the round, the government is expected to offer royalty and tax licenses, reflecting the high costs and risks associated with this type of exploration and development.

Local content requirements for E&P companies doing business in Mexico will gradually rise from 25% in 2015 to 35% by 2025. This mandate excludes deepwater and ultra-deepwater developments.

Some restrictions are included in the bidding process, as no company may take part in more than one joint bidding group for the same contract area; a joint venture of two companies having production of more than 1.6 MMbbl/d of oil, excluding deepwater, is prohibited; and companies or consortia may only bid on up to five contractual areas during the bidding process.

The bidding process has been impacted by the recent fall in oil price; Mexican authorities are currently reassessing the blocks to put on offer and selecting the appropriate fields. Following a first feedback from the industry, Mexico's energy regulator confirmed it would give oil companies a bigger share of profits and more flexibility in contracts compared to terms initially offered. Nonetheless, once bids are awarded by mid-2015 it should provide T&T with a benchmark of the contractual terms that the industry is ready to accept.

BHP Billiton has also signed a memorandum of understanding for sharing deepwater expertise with Pemex, and Petronas has also agreed to share expertise in deepwater, mature, and heavy oil fields with Pemex.

E.6 COLOMBIA: 2003 TAX REGIME IMPLEMENTATION

In 1974, Colombia implemented the so called "Association Contract" (similar to a PSC) whereby Ecopetrol (the Colombian NOC) was the oil & gas sector regulator as well as the partner of private companies for exploration and production activities.

At the beginning of the 2000s, as the result of the oil & gas regime implemented in the mid-1970s, the Colombian oil sector was in steady decline. Production was falling rapidly, from a 1999 peak of 800 kbbl/d down to 541 kbbl/d in 2003. The oil and gas industry was stagnating, with few new discoveries made, and Colombia's future energy self-sufficiency was in doubt. Furthermore, oil & gas infrastructure was threatened by guerrilla attacks.

A decisive shift was performed in 2003 under President Uribe, when the oil & gas regime moved to a concession-based regime from Association Contracts. Since then, oil production reached 1 MMbbl/d in 2013 and gas production doubled in 10 years to 200 kboe/d; reserves jumped to 2.4 billion barrels and 7 Tcf from 1.4 billion barrels and 3.7 Tcf respectively in 2007. It has to be noted that independent oil companies led the exploration efforts. In 2012 ExxonMobil returned to Colombia, two decades after having left.

Independent regulator, the Agencia Nacional de Hidrocarburos or ANH set up in 2003, manages exploration and production activities, and overall improvements in regulatory stability and internal security; while Ecopetrol is treated as any other investor in the sector in which private companies can hold a 100% working interest in the license. In 2007, the government sold 11.5% of Ecopetrol shares.

The new contract structure implemented in 2003 is a hybrid concession-type license offered via open competitive bidding. ANH acquired geological data to be included in the offering package when conducting the tender for oil and gas blocks. The tender selection criteria vary for each process but past rounds have been awarded on the basis of:

- Additional royalties or production shares offered to ANH (in addition to the royalties established under the law).
- Additional exploration investments (in excess of a minimum exploration commitment), or both.
- The new regime has also provided legal certainty for the investors, as investments are guaranteed by the state; the investors are given the possibility to enter legally stabilised contracts. Royalty levels were decreased by 5% to 25% among other incentive to attract foreign investment.

Figure E-5 Inward Foreign Direct Investment in Colombia
(source: Banco de la Republica)

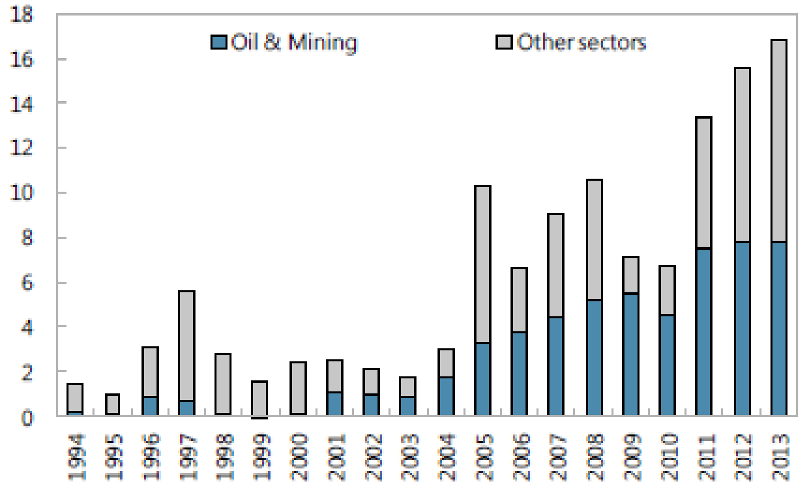


Figure E-6 Colombia Increased Exploratory Activity 2003 – 2013
(Source: ANH)

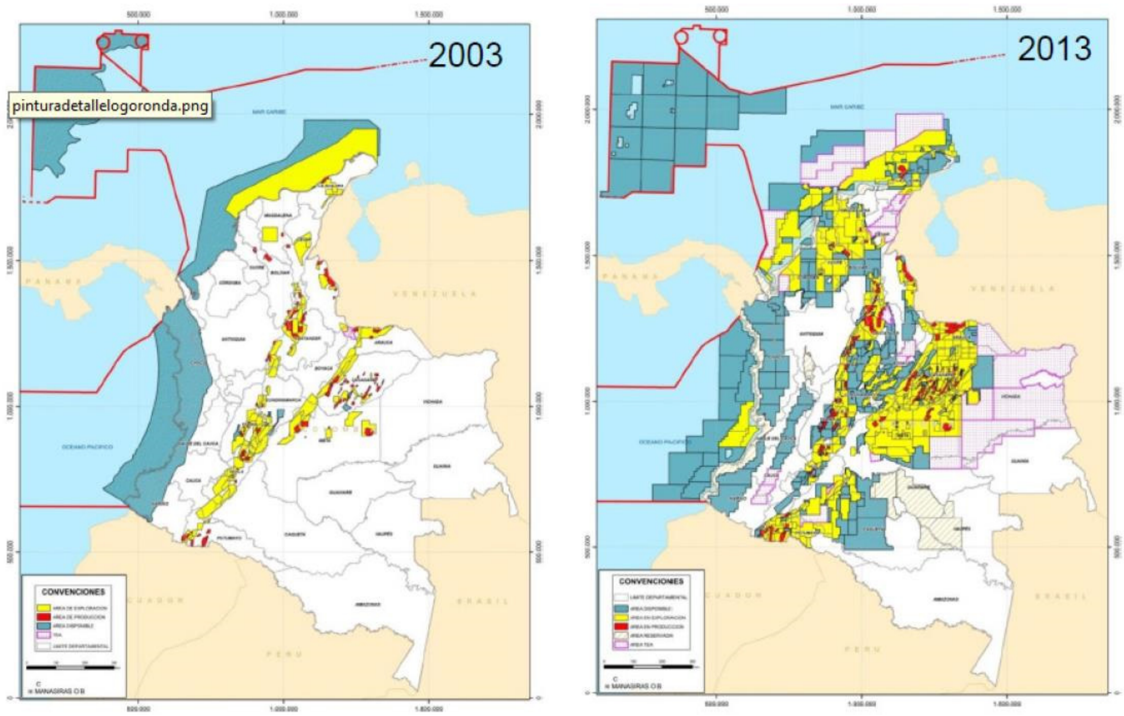


Figure E-5 to Figure E-8 illustrate that Colombia was very successful in developing its oil and gas industry indicated by foreign investments levels, the number of blocks explored, and the number of wells drilled in the country after the implementation of the new regulations in 2003 and improvement of exploration rounds' attractiveness.

Figure E-7 Wells Drilled in Colombia
(Source: ANH))

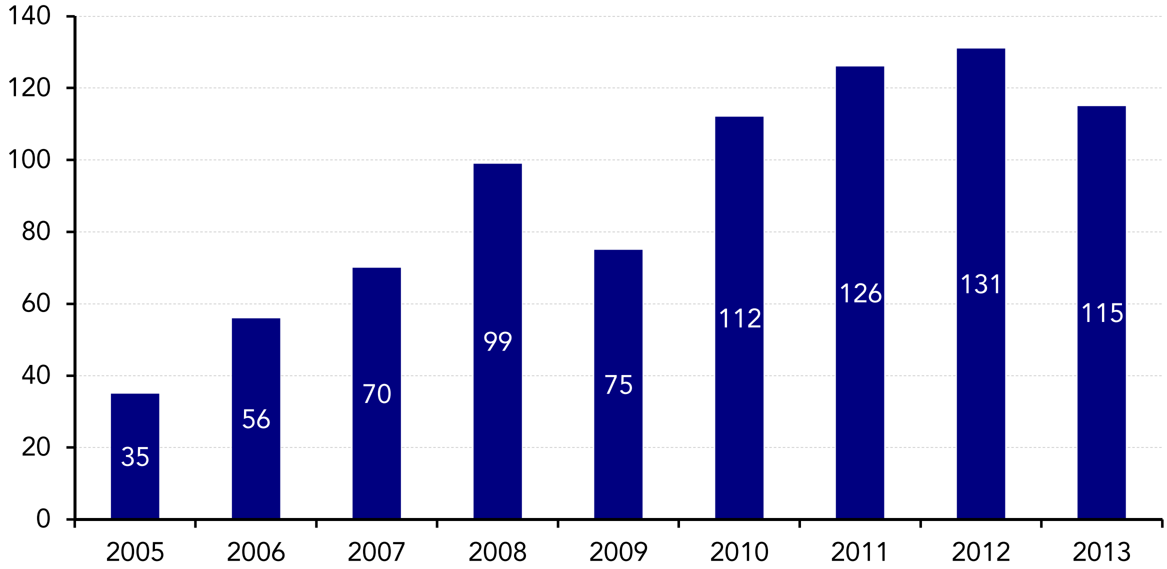
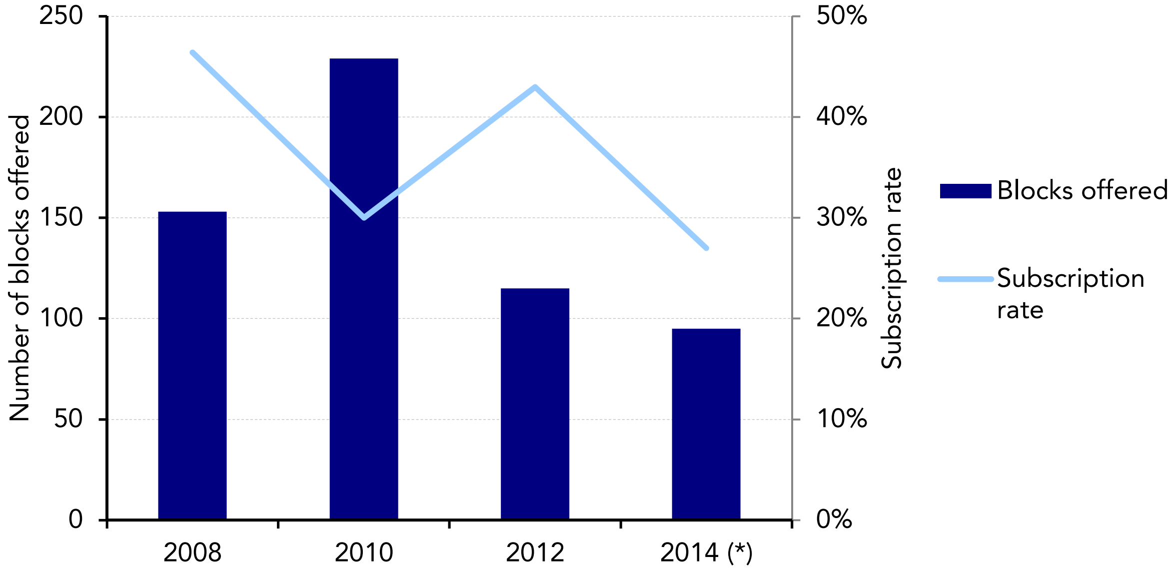


Figure E-8 Colombia Exploration Round Take-up
(Source: MME)



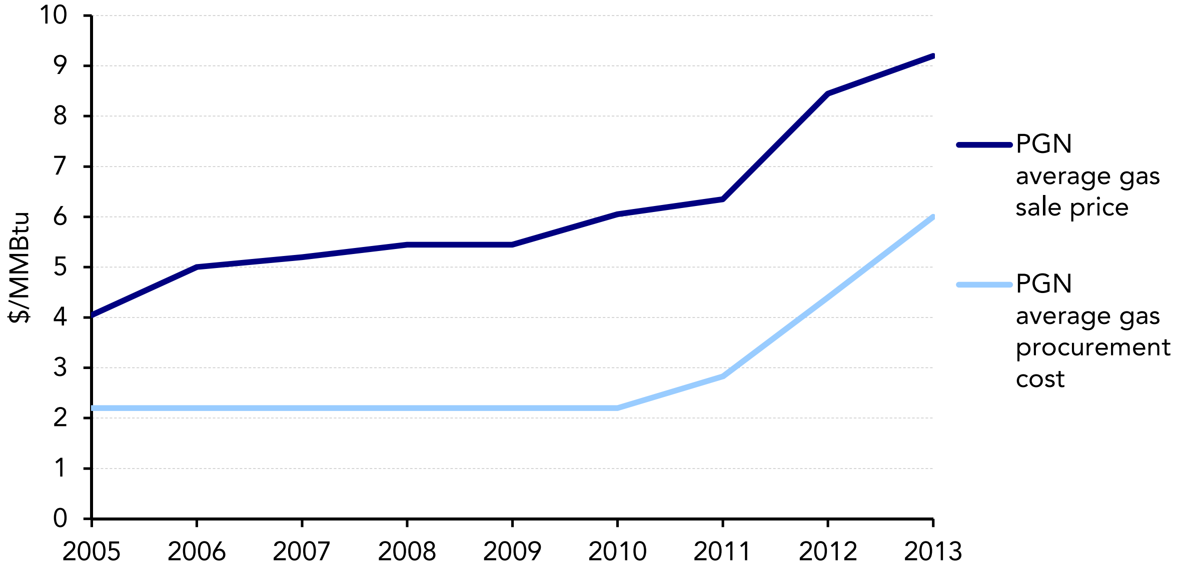
Another exploration round is currently in progress in Colombia ("Ronda 2014") and the results should be analysed for comparison in the benchmark group when available. The Colombian oil and gas sector current focus is on unconventional and offshore with the main companies leading the offshore exploration being: Ecopetrol, Petrobras, Shell, Repsol, Anadarko, Equion and Statoil.

E.7 OTHER REGULATORY CHANGES IN BENCHMARK COUNTRIES

In Malaysia, Petronas created in mid-2013 a dedicated subsidiary for marginal field developments. One of the strategic objectives of such a subsidiary is to build niche technical and executional capabilities in the development and production of small and marginal fields which can later be replicated for their overseas ventures.

South East Asian countries (Indonesia and Malaysia) as well as Egypt have implemented price reform over the last few years to soften their energy price subsidy burdens and make their growing energy markets attractive to upstream developers.

Figure E-9 Indonesian Gas Prices



As an example, fuel and electricity subsidies which represented $30 billion of the Indonesia state budget in 2013 are now being reduced. This trend in reforming energy sector and increasing end user prices has recently been accelerated to take advantage of low oil prices, reducing the impact on consumers.

F.1 INTRODUCTION

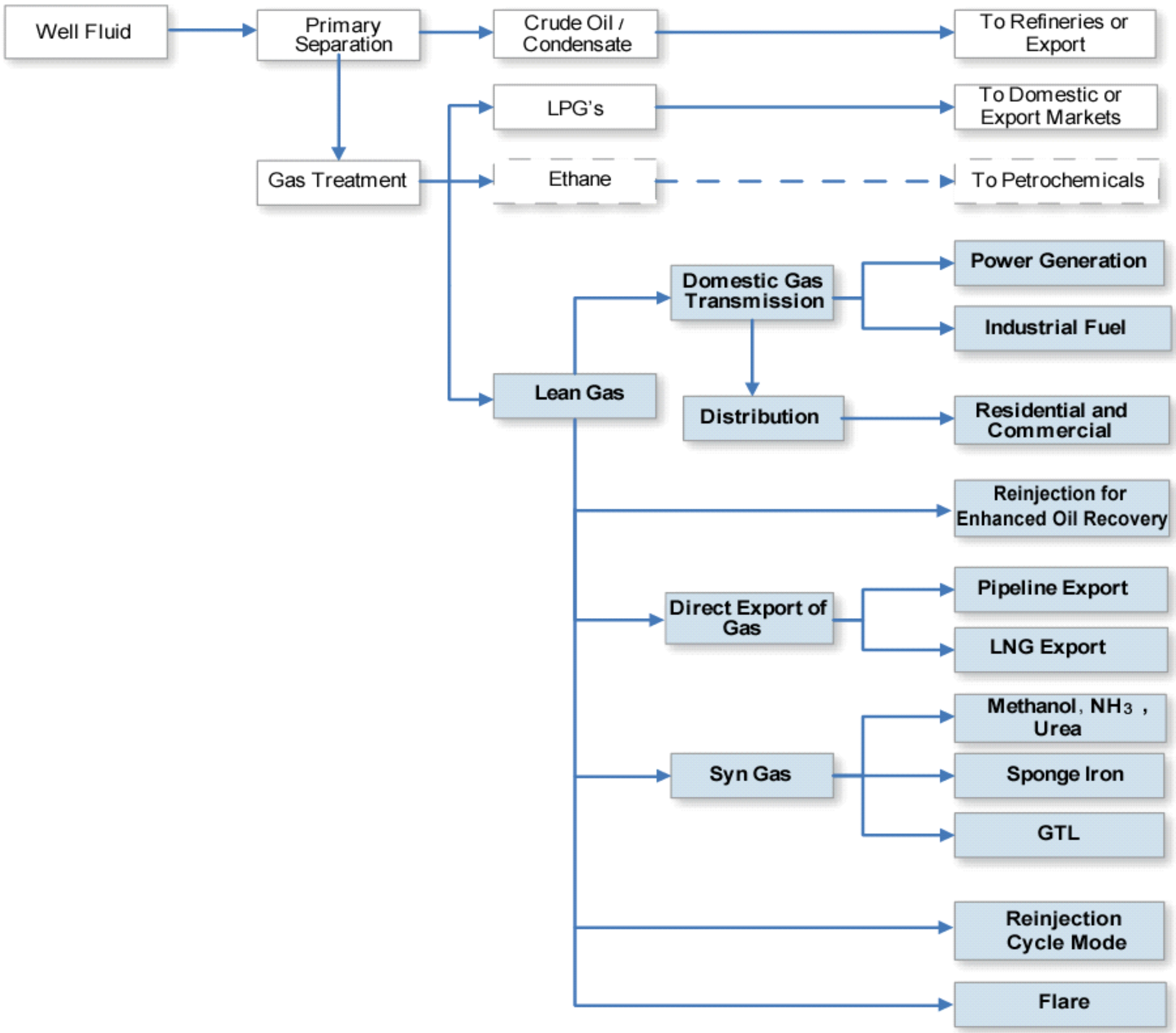
Although gas is a highly-prized source of energy and industrial feedstock, utilising indigenous gas reserves to the best advantage is often very challenging. There are multiple, often conflicting, financial, political and economic forces at work and the interests of resource holders, the host government and other stakeholders are not necessarily aligned in resolving key issues, which include the following:

- How much gas is needed for the local market?
- Are domestic gas or power options economic?
- Where exports are permitted, which options are likely to generate the greatest value?
- Value maximisation of the natural gas resource may not necessarily be consistent with government policy objectives, e.g. employment.

Many countries and resource developers have struggled with these problems and there are numerous examples of countries that have been left with sub-optimal gas utilisation assets or gas resources that have been left undeveloped. Understanding the gas utilisation options available and the relative value that each will generate for all parties is at the heart of solving this problem.

There are a range of options available for utilisation of natural gas as shown in Figure F-1. The uses range from domestic consumption for power generation and industrial production to, in the worst case, flaring of the gas. In general the value of gas is higher the higher up the chart it features. In most developed markets the utilisation of gas domestically as fuel for power and heat provides a higher value for the gas than exporting gas or gas-based products. Exporting involves the cost of transporting the gas, changing its state or transforming its chemical structure, and shipping it to a market where it has to compete with other sources of supply.

Figure F-1 Gas Utilisation Options



F.2 DOMESTIC CONSUMPTION

The most immediate use of gas is as a fuel in the domestic market, whether for power generation or other industrial uses, and in more temperate zones for domestic space heating. Utilising natural gas in the local power sector is typically the first consideration when looking at the various options.

Power can be generated very efficiently from gas in CCGTs where the thermal efficiency can exceed 60% in the latest machines. CCGT technology uses heat recovered from the hot exhaust gases within a gas turbine to raise steam for a conventional steam turbine. By comparison, conventional gas-fired boiler and steam turbine plants have efficiencies of up to 38%.

CCGT plants are normally a better choice than conventional boiler + steam turbine plant for gas fuel – they are more efficient and have lower capital and operating costs. Gas-fired boilers, however, have greater fuel flexibility than CCGTs in that they can be designed to also burn liquid fuels such as heavy fuel oil (if part of the original design specification).

A CCGT plant with a generation capacity of 1,000 MW would be expected to cost in the region of $1 billion and consume around 160 MMcf/d of gas (equivalent to ~1.0 Tcf over 20 years).

The emissions produced from gas burning are substantially lower than from other carbon sources and these units come in a range of sizes and can be installed relatively rapidly. In most countries these plants will run at baseload and mid-merit in terms of dispatch into the electricity market.

F.3 GAS EXPORT

The direct export of gas may be through pipeline or in the form of LNG. The choice here will depend upon the proximity of gas markets and the demand and pricing within those markets.

F.3.1 Pipelines

Generally the transportation of gas by pipeline is cheaper than the production and transportation of LNG up to distances of around 1,000 - 3,000 km although this is highly dependent on whether the pipeline is onshore or offshore, the terrain and/or seabed conditions, etc. Once built, pipelines can be expected to operate at low cost for many decades although clearly they cannot be moved anywhere else if market conditions change, so there needs to be long-term confidence in the market for the gas.

There have been significant advances in offshore pipeline laying technology in recent years and pipelines have been successfully laid in water depths of up to 2,900 m in the Gulf of Mexico. The Blue Stream pipeline across the Black Sea from Russia to Turkey reaches depths of 2,200m and delivers up to ~1.6 Bcf/d of natural gas at 250 bar in the 24 inch diameter submarine section.

There are two islands within pipeline distance from T&T: Barbados which is 380 km to the north east and Martinique which is 410 km to the north west. Although subsea pipelines would appear an obvious choice for gas supply connections from T&T to these islands there are a number of obstacles to this trade:

- Seabed conditions are difficult and the water depths challenging, and while within the scope of modern day pipeline laying techniques, such pipelines would be expensive.
- Economies of scale – the size of the local island gas markets are small, but pipelines require a significant baseload supply to support their development. The cost of the pipelines would be high relative to the volume to be delivered which would result in high pipeline tariffs.

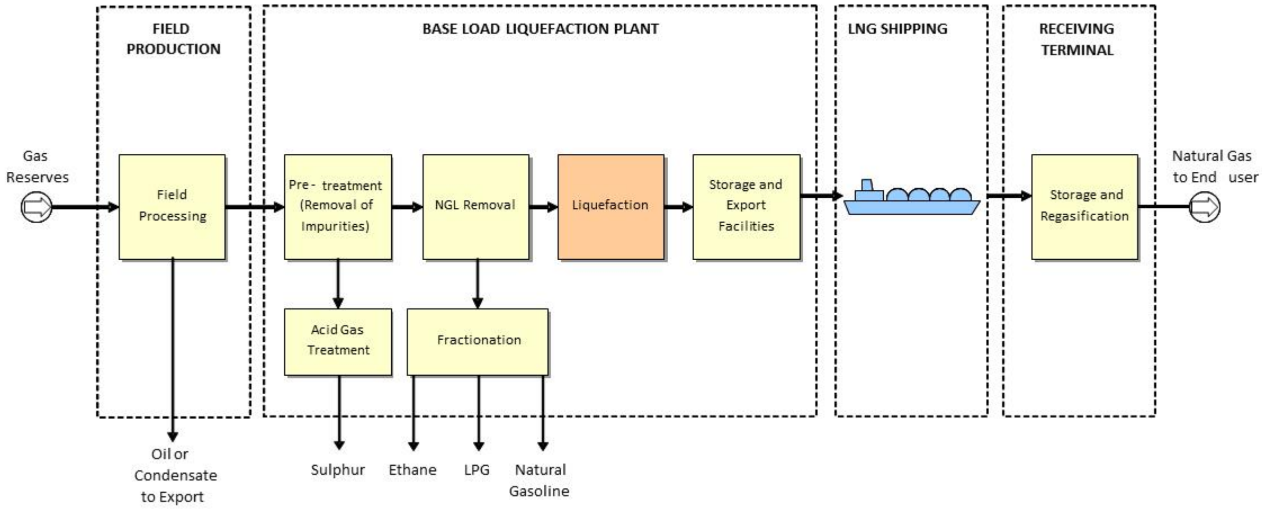
For example, it is estimated that a pipeline supplying 50 MMcf/d of gas to Barbados would require a tariff of ~US$9/MMBtu. This volume of gas would be more than that required to supply the entire power generation capacity of Barbados, totalling ~ 240 MW, if it were converted to gas.

F.3.2 LNG

LNG is a form of gas transportation where the gas is chilled to -160°C in a liquefaction plant to facilitate its shipping by specialised tanker. On delivery, LNG is regasified at a purpose-built receiving terminal in the importing market where it competes with other forms of gas for market share. The costs involved in the LNG chain are very high. A single train liquefaction train of 5 MMt/y will likely cost around US$5 billion, a single LNG tanker will cost in the region of US$250 million and a receiving terminal will likely cost around US$1 billion. Gas consumption for such a plant would be around 770 MMcf/d.

Both LNG and pipelines have significant economies of scale. There is a minimum practical size for each of these options and the larger the project the greater the economies of scale. The cost of an LNG plant has increased so much over the last decade that a ~8-9 MMt/y capacity greenfield plant is no longer uncommon.

Figure F-2 The LNG Chain



LNG is able to reach multiple markets but is not truly fungible. Because of the high investment cost, most LNG is sold on long-term contracts, typically of 20 years' duration. The logistics chain is quite rigid; ships are scheduled for a year ahead and confirmed on a quarterly basis. Primary regasification terminal capacity has to be sought on a long-term basis. LNG markets are discussed in detail in Appendix H of this report.

Liquefaction technology is based on a refrigeration cycle, whereby successive expansion and compression of a refrigerant removes heat from the incoming natural gas, thereby converting it to a liquid. LNG plants comprise one or more parallel units, called trains, which treat and liquefy natural gas and send the LNG to one or more storage tanks. The capacity of a liquefaction train is determined primarily by:

- The liquefaction process;
- The refrigerant used;
- The size of the compressor/driver used in the refrigeration cycle; and
- The type and capacity of the heat exchanger(s) that cool the natural gas.

The basic principles for cooling and liquefying gas using refrigerants involve matching, as closely as possible, the cooling/heating curves of the process gas and the refrigerant. The better the match between these two curves, the better the efficiency of the thermodynamic process. The more efficient the thermodynamic process, the less power required per unit of LNG produced.

The liquefaction section typically accounts for 30-40% of the capital cost of the overall LNG liquefaction plant. Key equipment items include: the compressors used to circulate the refrigerants, compressor drivers, and heat exchangers used to cool and liquefy the gas and exchange heat between refrigerants. For some recent baseload LNG plants, this equipment is among the largest of its type and at the leading edge of technology. Because LNG liquefaction requires a significant amount of refrigeration energy, the refrigeration system represents a large portion of an LNG facility. While a number of liquefaction processes have been developed, the principal differences between technologies are mainly confined to the type of refrigeration cycle employed.

- Air Products & Chemicals, Inc. (APCI) Propane Pre-Cooled Mixed Refrigerant (C3-MR) Process and the AP-X Process Technologies;

- ConocoPhillips Optimised Cascade Process (OCP) Technology;
- Shell Dual Mixed Refrigerant (DMR) Technology; and
- Statoil-Linde Mixed Fluid Cascade (MFC) Process Technology.

The two leading liquefaction suppliers are APCI and ConocoPhillips (CP). The ALNG project utilises the OCP technology. This technology has tended to be used where the gas is leaner.

A world-scale LNG train is around 4-5 MMt/y although mega trains of 7.8 MMt/y have been built in Qatar using APCI technology. Typically, a greenfield project will be built using at least two trains in order to take advantage of the economies of scale, i.e. larger trains will lead to a lower capital cost per tonne of capacity and the infrastructure costs are similar for a single train or double train project.

The LNG industry developed slowly during the second half of the last century before rapid growth over the last 10-15 years. In the early 2000s, prices for constructing LNG plants fell as new technologies emerged (and Atlantic Train 1 was a notable example of the use of alternate technology that had not been used for several decades) and more EPC contractors became involved in construction. However, later in the decade construction costs rose as the sector overheated and materials costs increased.

F.3.3 Floating LNG

Floating LNG (FLNG) has emerged as a means of utilising offshore gas reserves once deemed too remote, too small, or otherwise too difficult for conventional land-based LNG development or where there are other environmental factors that would preclude onshore liquefaction. There are four projects that have reached project sanction and a number of others in various stages of development.

The benefits of FLNG over conventional onshore liquefaction plants are as follows:

- FLNG units can be stationed directly over an offshore field, eliminating the need for a long and costly subsea pipeline to shore, and significantly slashing investment in marine and loading facilities.
- FLNG units are built in a yard environment which is much more controlled than a traditional stick-built project. This potentially allows for a shorter development and construction time schedule.
- FLNG may be a suitable solution where onshore sites are scarce or there are environmental issues around site selection.
- Floating assets potentially reduce security and political risks in some of the less stable regions where stranded gas is increasingly being found.
- Finally once the field is depleted, the unit can potentially be relocated to another gas resource. However, the ability to do this in practice is questionable, as different gas fields have different specifications of gas which makes designing the gas processing units challenging.

There are a range of different projects or concepts are at varying stages of project development. FLNG units are emerging at two different scales: large scale, which is generally comparable to a land-based LNG train size and smaller scale units which use a more simple process arrangement. These are shown in Table F-1 below:

Table F-1 Large and Small-Scale FLNG Units

	Small Scale	Large Scale
Liquefaction capacity	< 3.0 MMt/y	3.5 – 6.0 MMt/y
Required reserves	0.5 – 3.0 Tcf	> 3.0 Tcf
Hull	Ship-like	Barge-like
Storage capacity	< 220,000 m³	> 250,000 m³
Liquefaction processes	Simpler processes (e.g. Single Mixed Refrigerant, Dual Expander)	Baseload-type processes (e.g. Dual MR, Mixed Fluid Cascade)

Large-scale projects are generally in the domain of large international and national oil companies, such as Shell, which possess the assets, technical and financial resources, and tolerance for risk to advance these projects. The Shell-led Prelude LNG project, off the northwest coast of Australia, is the largest capacity FLNG unit currently under construction. Upon completion, the 488 m long by 74 m wide vessel will be the largest man-made floating object in history. It will be anchored for 25 years at a location 475 km north-northeast off Broome and 825 km west off Darwin, at 250 m water depth. The unit is designed to produce 3.6 MMt/y of LNG, 0.4 MMt/y of LPG, and 1.3 MMt/y of condensates. The vessel will have six membrane LNG tanks totalling 220,000 m³ of storage capacity, along with 90,000 m³ of LPG storage and 126,000 m³ of condensate storage. FID was taken in 2011 and the project startup is expected by 2016.

Table F-2 Status of Large-Scale FLNG Projects

Project	Country	Sponsor	Size (MMt/y)	Status	FID	Startup
Prelude	Australia	Shell, Inpex, Kogas	3.6	Construction	2011	2016
Browse	Australia	Woodside, Shell, BP, Mitsubishi, Mitsui, PetroChina	4.0 x 3	Planning	2016 (Delayed from 2015)	2021
Lavaca Bay	US Gulf Coast	Excelerate	4.4	On hold	TBA	TBA
Scarborough	Australia	BHP Billiton, ExxonMobil	6.5	Prospective	TBA	TBA
Kitsault Energy	Canada	Kitsault Energy	5.0 x 4	Prospective	TBA	TBA
Cedar	Canada	Haisla First Nations	TBA	Prospective	TBA	TBA
Orca	Canada	Orca LNG	4.0 x 6	Prospective	TBA	TBA
Greater Sunrise	Australia	Woodside, ConocoPhillips, Shell, Osaka Gas	4.0	(On hold)	TBA	TBA

There has been some attrition of planned projects. The Lavaca Bay project under development in the USGC has been put on hold recently, while the Scarborough project in Australia has had its FID deferred until at least 2016, reflects the challenging economics of these projects in a lower oil price environment.

Smaller scale FLNG projects are also making some headway. There are two Petronas projects under construction for deployment offshore Sabah and Sarawak in Malaysia. These projects are of 1.2 & 1.5 MMt/y liquefaction capacity and the first is scheduled to start up in 2015. The roster of smaller scale projects under development is shown in the table below:

Table F-3 Status of Small-Scale FLNG Projects

Project	Country	Sponsor	Size (MMt/y)	Status	FID	Startup
Kanowit	Malaysia	Petronas	1.2	Construction	2012	2015
Rotan	Malaysia	Petronas	1.5	Construction	2014	2017
Caribbean	Colombia	Pacific Rubiales, Exmar	0.5	Construction	2012	2015 (Planned)
Cameroon	Cameroon	SNH, Perenco	1.2	Planning	2015	2017
Woodfibre	Canada	Pacific Oil & Gas	2.0	Planning	2015	2017
Douglas Channel LNG	Canada	Altgas, Idemitsu, EDF, Exmar	0.55	Planning	2015	2018
Mozambique	Mozambique	Eni	2.5	Planning	2015	2019
Triton	Canada	Altagas, Idemitsu	2.3	Planning	TBA	TBA
Abadi	Indonesia	Inpex, Shell	2.5	Planning	TBA (Delayed)	TBA
Fortuna	Equatorial Guinea	Ophir	3	Planning	TBA	TBA
Cash-Maple	Australia	PTTEP	2.0	Prospective	TBA	TBA
Gabon	Gabon	Shell	2.0	Prospective	TBA	TBA
PNG	PNG	Hoegh, DSME, Petromin	3.0	Prospective	TBA	TBA
Santos Basin	Brazil	Petrobras + others	2.7	(On hold)	TBA	TBA

However, there are a number of risks associated with the technology that leave development prospects for many of these projects uncertain:

- Although several FLNG projects are under construction, none have yet started operation. As such FLNG technology remains unproven and there is still some uncertainty as to how FLNG will work in practice. There is no precedent for offshore liquefaction and the most similar FPSO vessels used for processing gas and LPG are less technically complex.
- A key concern is the availability of the facility to produce LNG in severe marine conditions and the related issue of offloading products by ship-to-ship transfer. It is no coincidence that the early projects will be located in areas with relatively benign metocean conditions.
- The costs are at present unknown. This is discussed in more detail below.

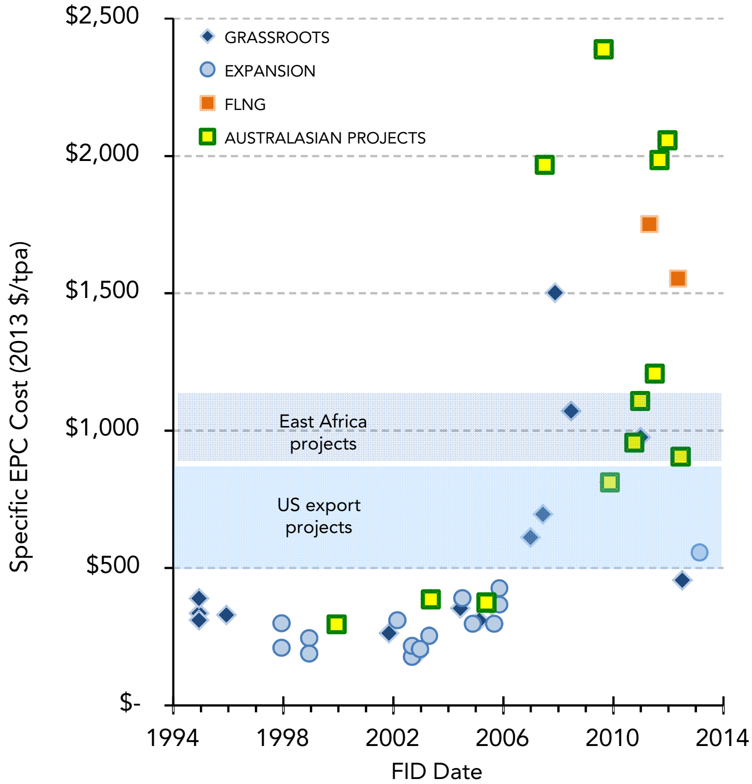
- Insurance costs will be high. The severity of the loss of the hull is high, as it is equal to the loss of the entire project. This will result in higher insurance premiums.
- Given that the technology is still at an immature stage there is no possibility to finance FLNG projects using project finance, which is the conventional means of raising finance for LNG projects. At this stage developers will need to self-finance projects, and only when projects have been running for several years will commercial finance be available.

In terms of the risks associated with offshore LNG production, it is pertinent to note that quite a number of the planned projects, e.g. those in Canada, are expected to be permanently moored at coastal jetties rather than moored in the open ocean.

Costs of FLNG Development

The costs of FLNG developments are still mainly unknown. The first projects remain under construction and the final costs will only be known once they are complete (although even then these costs are unlikely to be made available in the public domain). However, the likelihood is that these projects will not be low cost. Initial indications put the costs at \$1,500 to \$2,000/tonne of liquefaction capacity, which is more competitive than recent projects in Australia but is significantly more expensive that US export projects, and is expected to be above the cost of East African projects.

Figure F-3 EPC Costs: FLNG vs. Conventional Projects



The operating costs of FLNG are expected to be as high as two times that of the land-based plants, due to higher fuel, labour and maintenance costs, and the remote locations of the vessels.

Given the uncertainties around capital and operating costs, the economics of FLNG have yet to be demonstrated. It is a relevant observation that the Prelude project is draining a field which is rich in gas condensates and it is likely that these liquids will play an important role in the project's economic viability. This will not be the case for many of the planned projects.

As the deliverability of the early projects is not assured it will be important that early developers find a way to backstop offtake or negotiate some flexibility in LNG supply contracts. Both Shell and Petronas are able to do this with supply from their broader portfolios, which mitigates a key risk for offtakers.

F.3.4 Small-Scale LNG

While there is no universal set of specifications for what constitutes "small scale", small-scale LNG generally includes any projects that conform to the following capacities:

- Liquefaction plants: <1 MMt/y
- LNG Carriers: <30,000 m³ to as little as tens of m³.
- LNG regasification terminal: <0.5 MMt/y (~65 MMcf/d)
- Land-based storage tanks: 100 m³ to 50,000 m³.

Small-scale LNG can be sourced in two ways: small-scale LNG plants or break-bulk LNG terminals. Small-scale LNG plants are best used to monetise small, scattered, and stranded gas fields. The primary example of this is the exploitation of the gas fields in northwest China[1].

Break-bulk terminals offer a less costly source of small-scale LNG, as break-bulk terminals do not require capital-intensive compressors but mainly pipes and pumps to break LNG received at a terminal into smaller volumes, and load the quantities onto vessels or trucks for distribution. Two typical examples of break-bulk terminals are Zeebrugge LNG in Belgium and Gate LNG in the Netherlands. Both terminals break conventional scale LNG supply into smaller volumes and supply them to small-scale LNG terminals in the Baltic Sea and Rhineland regions via small vessels and barges.

Small-scale LNG has grown substantially in the last decade. Currently global consumption is around 10-11 MMt/y but this is expected to grow to 35-50 MMt/y by 2025. This is estimated to be 8-10% of the global LNG traded market at that time.

Small-scale LNG is used for two primary functions: power generation or transport fuel. In power generation, small-scale LNG can fuel gas-fired power plants in remote and off-grid areas, so as to industrialise and electrify those areas. This is exemplified by China and Indonesia. China has a number of stranded gas fields scattered in its northwest part, where villages and small towns are barely connected with main gas and power grids. Consequently, small-scale LNG can serve as an economic way for power generation to electrify those areas.

Small-scale LNG is always considered as an option for serving the power sector in suitable locations, particularly island nations and archipelagos. Several schemes have been considered for the South East Asia, the Caribbean and Mediterranean.

The Caribbean archipelago appears to be a good fit for the use of small-scale LNG into power generation. Since the power demand on each island is small, it is uneconomical to lay subsea cables to connect all islands as a centralised power grid, and consequently, each island has its own oil product-fired power plants. The issue for the use of small-scale LNG is usually one of scale. There needs to be sufficient

[1] China now has the most small-scale LNG plants, over 40 plants with a total liquefaction capacity over 8.5 MMt/y. Moreover, around 80 more plants are under planning. The plants are supplied with gas directly from small gas fields or from gas pipelines. Manufacturers such as Linde, GE, Wartsila, Chart, and Cryostar provide small-scale liquefaction technology.

aggregated demand to justify the investment on the part of the supplier. The infrastructure costs are relatively high, as each island must develop receiving facilities, requiring high end user gas prices to achieve economic viability.

At present, the primary use of small-scale LNG is for transportation. As a transport fuel, LNG can fuel vessels or heavy duty vehicles (HDVs), for which the higher energy density of LNG has advantages over compressed natural gas (CNG). Vehicles are expected to remain the major consumer of small-scale LNG for the next decade, increasing gradually from 9.5 MMt/y in 2014 to 22 MMt/y in 2025. Meanwhile, bunkering LNG is expected to present the largest longer term growth prospect, jumping from 0.1 MMt/y in 2014 to 9 MMt/y in 2025.

F.3.5 Compressed Natural Gas (CNG)

Compressed natural gas (CNG) is made by compressing natural gas to less than 1% of its volume at standard atmospheric pressure (STP) at a pressure up to 250 bar. For this purpose natural gas is simply mechanically compressed, as it is in a pipeline. Unlike LNG, CNG does not require complex and expensive refrigeration, although the energy density of LNG is 2-3 times that of CNG. CNG-fuelled vehicles are relatively common around the world in countries with indigenous gas resources. CNG as a means to transport gas by ship is a concept that has been mooted for many years but has yet to be commercialised. Both of these options are discussed subsequently.

F.3.5.1 CNG Vehicles

CNG can be used in vehicles with engines designed to run on natural gas or in dual-fuel vehicles with petrol. Vehicles can be fitted with CNG car kits to convert petrol engines to run on CNG but will still have the capability to run on petrol as well. Due to the relatively low energy density/large storage volume requirements of CNG it is largely used to fuel light duty vehicles such as private cars and light buses.

Figure F-4 CNG Vehicles / Infrastructure

The world has around 18 million NGVs across over 80 countries, although CNG use in vehicles is relatively widespread in only a limited number of countries/regions, including Latin America (Argentina, Brazil, Colombia), South Asia (Pakistan, India, Bangladesh), China, Iran and Italy. The top five countries with the most CNG vehicles in descending order are: Iran, Pakistan, Argentina, Brazil, and China, which together account for around two-thirds of the global total number of vehicles.

CNG vehicles are often restricted to particular urban regions due to infrastructure limitations and the limited range of the CNG vehicle. In order to promote the adoption of CNG vehicles, government incentives to convert have usually been provided through favourable fiscal treatment of natural gas as a vehicle fuel. In a few cases there has been compulsory conversion to CNG for environmental reasons, for example in Delhi and Agra in India the courts banned the use of high sulphur gasoline and diesel in public vehicles.

Leaving aside economic competitiveness, widespread implementation and utilisation of CNG vehicles requires well-developed gas pipeline infrastructure, substantial investment in new distribution and filling station infrastructure, the implementation of rigid technical and safety standards, and substantial training of refuelling staff. These factors help to explain the relatively limited uptake of CNG as a vehicle fuel.

Storage safety for vehicles is a further concern, with CNG storage in pressurised containers at a pressure 70 times higher than an LPG tank. Road accidents involving CNG storage could lead to explosions with potential severe consequences.

F.3.5.2 CNG for Ocean Transportation

Marine CNG is the transportation by ship of natural gas stored under pressure. For this purpose natural gas is simply mechanically compressed, as it is in a pipeline. Unlike LNG, CNG does not require complex and expensive refrigeration. Consequently, while the energy density of LNG is 2-3 times that of CNG and therefore requires less shipping capacity, CNG loading and discharge facilities are much simpler, much less expensive and have a significantly smaller footprint.

Figure F-5 Marine CNG Transportation Chain

As a result CNG is expected to offer a lower cost gas transportation option than LNG for smaller volumes of gas over shorter distances (<1,500 – 2000 nautical miles), with easier and quicker permitting and implementation. CNG also has the added benefit that the majority of investment will be in the ships, which will be able to be redeployed to other projects as required.

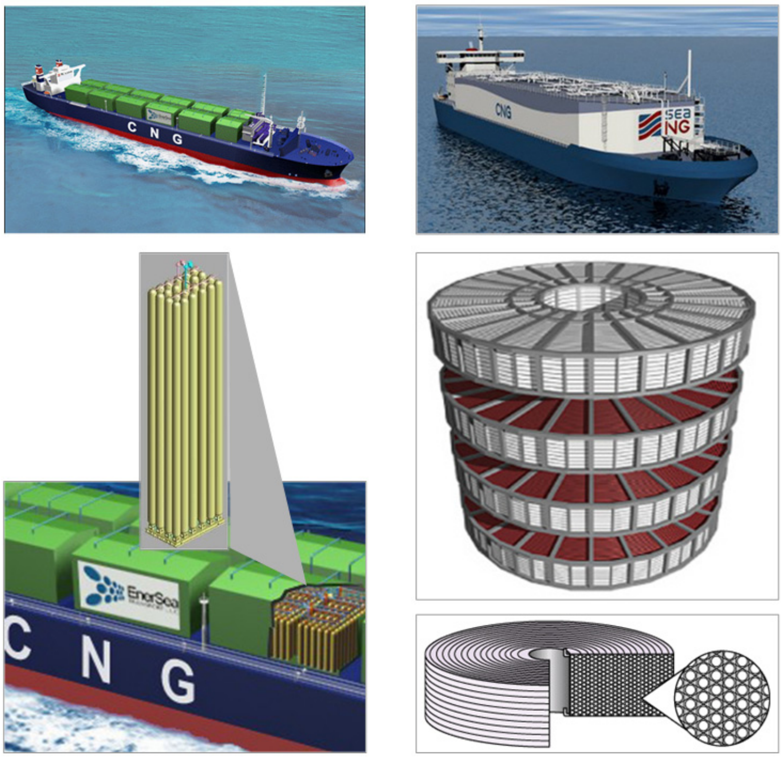
Other drivers for CNG development include the following:

- Potential recovery of smaller stranded gas reserves (0.5 – 2 Tcf) too small or unsuitable to support onshore or floating LNG.
- Lower investment cost, relative to LNG, potentially allowing smaller oil/gas companies to monetise their gas resources.
- Lower gas consumption in processing and operation (3-4% vs. ~9% for LNG liquefaction).
- Wider gas composition can be processed compared with LNG.

There are a number of developers of CNG technology; however, the two considered to have the leading technology concepts are Enersea and Sea NG:

- In the Enersea system, CNG is refrigerated and stored in banks of pressure vessels. This significantly lowers transportation pressure in comparison to other CNG options by operating at or near compressibility minima for transported gas.
- In the Sea NG system, gas is stored in long spiral-wound pipe coils (Coselles) at ambient temperatures. Hence significantly higher pressures are required for economical gas transportation than for Enersea's refrigerated concept.

Figure F-6 CNG Ocean Transportation Concepts
(source: Enersea, Sea NG)



Despite the potential being touted by technology providers and the concept being studied extensively over many years, no ships to transport CNG have yet been developed and there are none on order. Key issues that have impeded development include the following:

- Unproven technology would make commercial financing very difficult / impossible to come by. In comparison LNG ship financing is very common and lenders are highly familiar and comfortable with the risks involved. Equity financing of shipping will substantially add to the capital intensity of a CNG project.
- Expected high capital costs and cost uncertainty due to the unproven nature of the technology - delays and cost overruns are typical with the introduction of new technology or concepts.
- "Chicken-and-egg" situation for vessel redeployment opportunities; there will be no redeployment opportunities until a range of projects are developed and a lack of redeployment opportunities adds substantial risk to projects being developed.

There has been limited development in marine CNG projects recently, including moving CNG containers by ship in Indonesia, but no commercialisation yet of a “true” marine CNG vessel-based project. The first marine CNG project will probably be commercialised in South-East Asia, which offers developers the best prospect of initial success (numerous stranded gas assets, relatively high value gas markets to target, relatively benign marine conditions in many areas.).

F.4 OTHER LNG OPTIONS

F.4.1 LNG as a Bunker Fuel

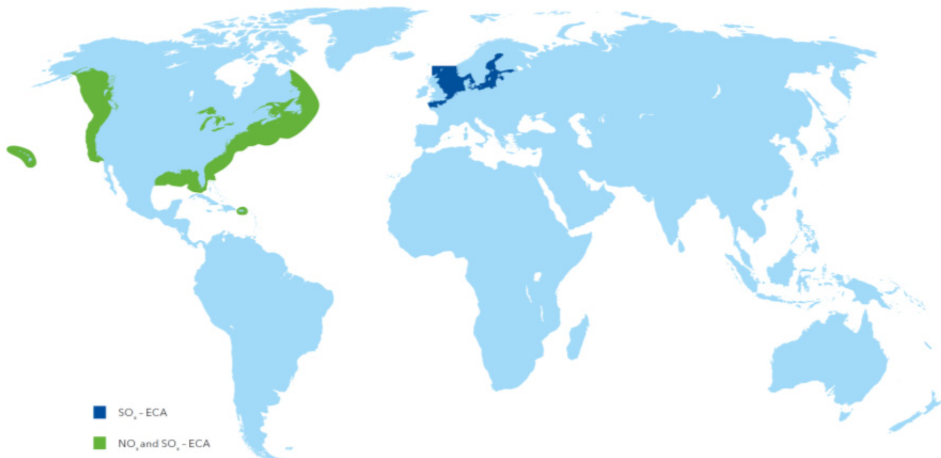
The use of LNG as a marine bunker fuel is being driven by environmental/regulatory forces. Heavy fuel oil (HFO) is generally the lowest cost fuel available for marine bunkers but it has the highest level of emissions on combustion. The use of gas in the form of LNG can reduce NO_x emissions by nearly 80% and SO_x emissions by 100% compared to burning HFO.

Ship exhaust gas emissions are being drastically reduced following the International Maritime Organization (IMO) International Convention for the Prevention of Pollution from Ships (MARPOL) Annex VI which entered into force in 2005.

- The mandate limits the sulphur content of marine fuels on a global basis to 4.5%. That limit was then lowered to 3.5% from January 2012.
- A 1.5% sulphur limit on marine fuels in Emission Control Areas (ECAs) was also imposed, effective May 2006. That limit was reduced to 1.0% from July 2010 and to 0.1% from January 2015.

As a result, the effects of Annex VI sulphur reductions and initiatives to adopt lower sulphur fuels have been largely limited to the ECAs thus far (shown in Figure F-7 below – further ECAs are under discussion for the Mediterranean, Mexico, Singapore, Japan, Hong Kong, Korea, Australia and the Black Sea).

Figure F-7 Existing Emission Control Areas
Source: DNV

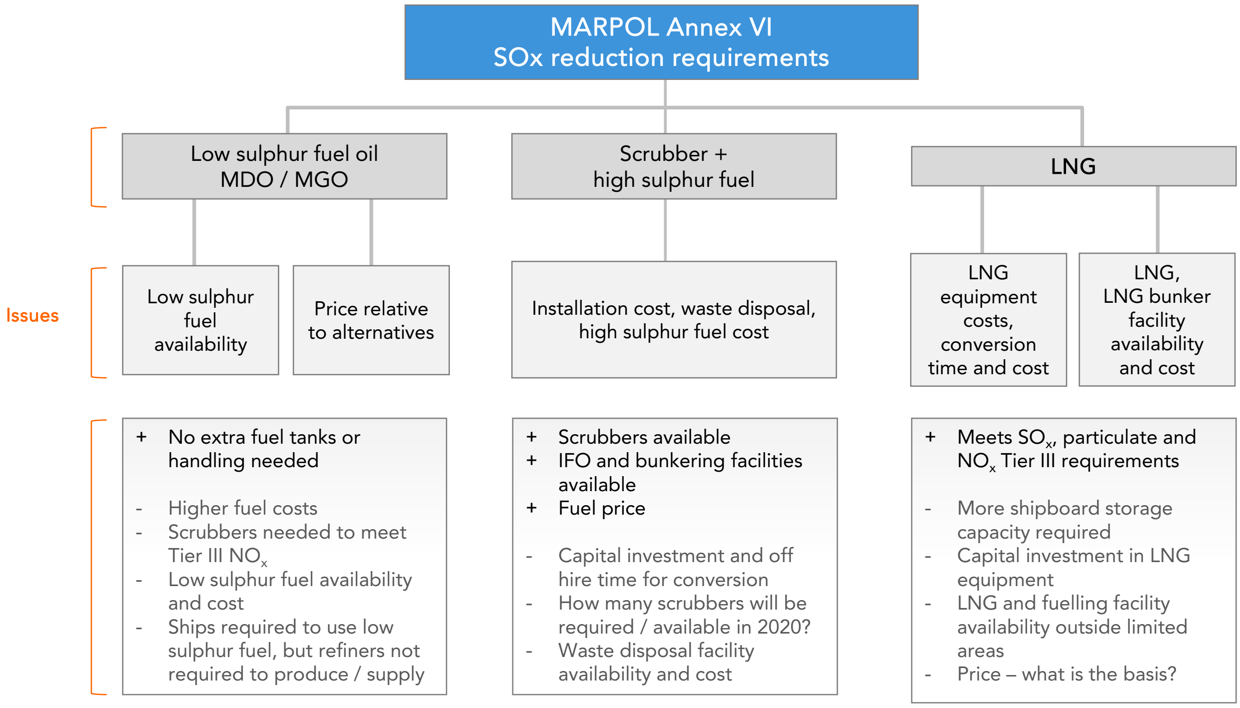


The larger effect from Annex VI will come from the requirement to reduce sulphur content of marine fuels to 0.5% on a global basis. This was originally scheduled to take place in 2020, but the timing depends on an IMO study to be completed in 2018. If IMO decides there is insufficient low sulphur fuel available, the 0.5% limit can be delayed until 2025. Poten expects that the delay to 2025 will happen.

The issue for shipowners and operators is how to find alternatives to economically meet these mandates. In the short term, shipowners and operators are switching from traditional (high sulphur) bunker fuel during ocean passages to low sulphur fuels when operating in ECAs. For the longer term, shipowners are studying alternative approaches to meet the environmental requirement for the post-2020 or 2025 era; these include (as shown in Figure F-8 below):

- Secure a reliable and affordable source of Annex VI compliant liquid fuel;
- Consume high sulphur fuel and add emission reduction equipment (e.g. scrubbers) to meet limits;
- Shift to an alternative low sulphur fuel. LNG is one alternative attracting attention because of its negligible sulphur content and its price, which is typically lower than the traditional residual oil-based bunker fuels.

Figure F-8 Competition with LNG for Bunker Fuel Markets



Shipowners have constructed an estimated 30 LNG-fuelled ships and have ordered over 30 more. However, to date LNG bunkering is very limited and initiatives for LNG as a marine fuel are largely regional, i.e. ships deployed in trade routes between ECAs or ships trading entirely within ECAs.

For example, ships trading from the Baltic Sea to North Sea and English Channel routes are now complying with a 0.1% sulphur requirement for all or a substantial portion of their voyages. Initiatives by shipowners and governments have already resulted in construction and operation of LNG-fuelled ships and development of small-scale LNG supply and fuelling infrastructure within these European ECAs, which became effective in 2006 and 2007. Much of the LNG fuelling is taking place in the Baltic, with

Norway the leading supplier. Shell is a leading player having purchased Gasnor, which operates small-scale liquefaction facilities in Norway and supplies LNG for marine fuel.

LNG-fuelled ships are now also being ordered for trading entirely within the North America ECA in response to U.S. Environmental Protection Agency regulations and introduction of the North America ECA from August 2012.

LNG offers strong benefits to meeting the emission mandates:

- No additional measures needed to reach ECA limits.
- CO_2 reduced by about 20%; particulate emissions virtually eliminated.
- Increasingly proven operation.
- Waste heat recovery possible.

However, challenges to the wider implementation of LNG as a bunker fuel are significant:

- Requires purpose-built or modified engines and a sophisticated system of special fuel tanks, a vaporiser, and double walled gas piping.
- LNG produces about 20% less power than Marine Diesel Oil (MDO), requiring larger drivers for equivalent power output.
- Overall greenhouse gas performance is about the same as burning MDO due to a small amount of the methane fuel feed "slipping" through unburned.
- Requires ~ 60% greater storage volume than Intermediate Fuel Oil (IFO) and ~50% more than MDO.
- Requires gas-safe designed engine room.
- Regulations not finally settled.
- Limited existing LNG bunkering infrastructure.

As a result, although there is undoubted market potential, Poten expects the global demand for LNG as a marine fuel to remain below 10 MMt/y by 2025.

F.4.2 LNG as a Vehicle Fuel

Restrictions on emissions are driving the implementation of natural gas as a vehicle fuel, as discussed previously for CNG. In comparison to CNG, LNG is well suited for use as a transport fuel on vessels and trucks where space for fuel storage is at a premium. In addition engine combustion is slightly more efficient due to lower intake temperature, while cool air for passengers or cargoes can be obtained when LNG vaporises through a heat exchanger before entering the engine. As with CNG, dual-fuelled engines are generally preferred.

Figure F-9 LNG as a Vehicle Fuel

Source: Blue Corridor

Source: Cryostar

Broadly speaking, the major markets for LNG as a vehicle fuel at present are limited to Europe, the US, and China. In Europe, demand for LNG as a vehicle fuel is expected to grow steadily; it currently accounts for 25% of total gas consumption by natural gas vehicles (NGVs). Europe currently has 43 LNG refuelling stations, primarily located in Spain and the UK. In the US, LNG-fuelled buses and heavy duty vehicles (HDVs) account for over 50% of total gas consumption by NGVs currently. The US has 46 LNG refuelling stations. China has a large number (around 440k) of LNG-fuelled buses and HDVs along with 1,330 LNG refuelling stations.

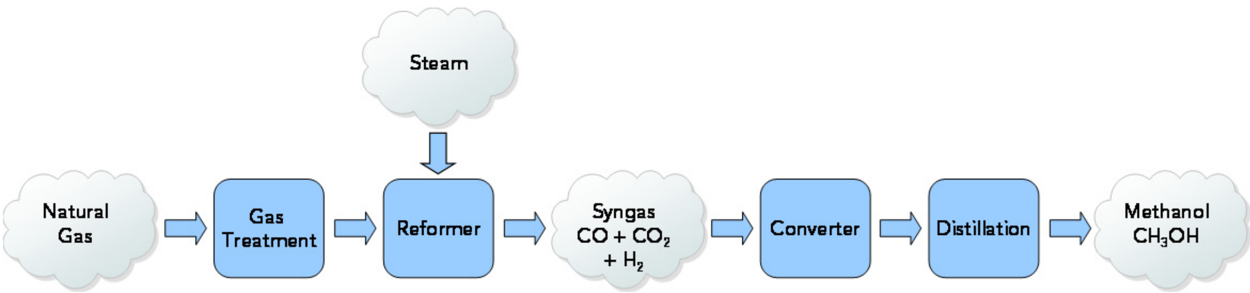
F.5 GAS-BASED PETROCHEMICALS

The second set of options is to develop gas-based petrochemicals, which involves rearranging of the methane molecules under high pressure/temperature to produce chemicals with a different molecular structure.

F.5.1 Methanol

Methanol is a natural gas-based chemical that is manufactured by breaking the methane molecules into "syngas" ($CO/CO_2/H_2$) via a reforming process, as shown in Figure F-10 below. The syngas is then cooled, compressed and passed over a copper-zinc catalyst to produce crude methanol via a synthesis process. To produce chemical-grade methanol, the crude methanol is distilled to remove water, higher alcohols and other impurities.

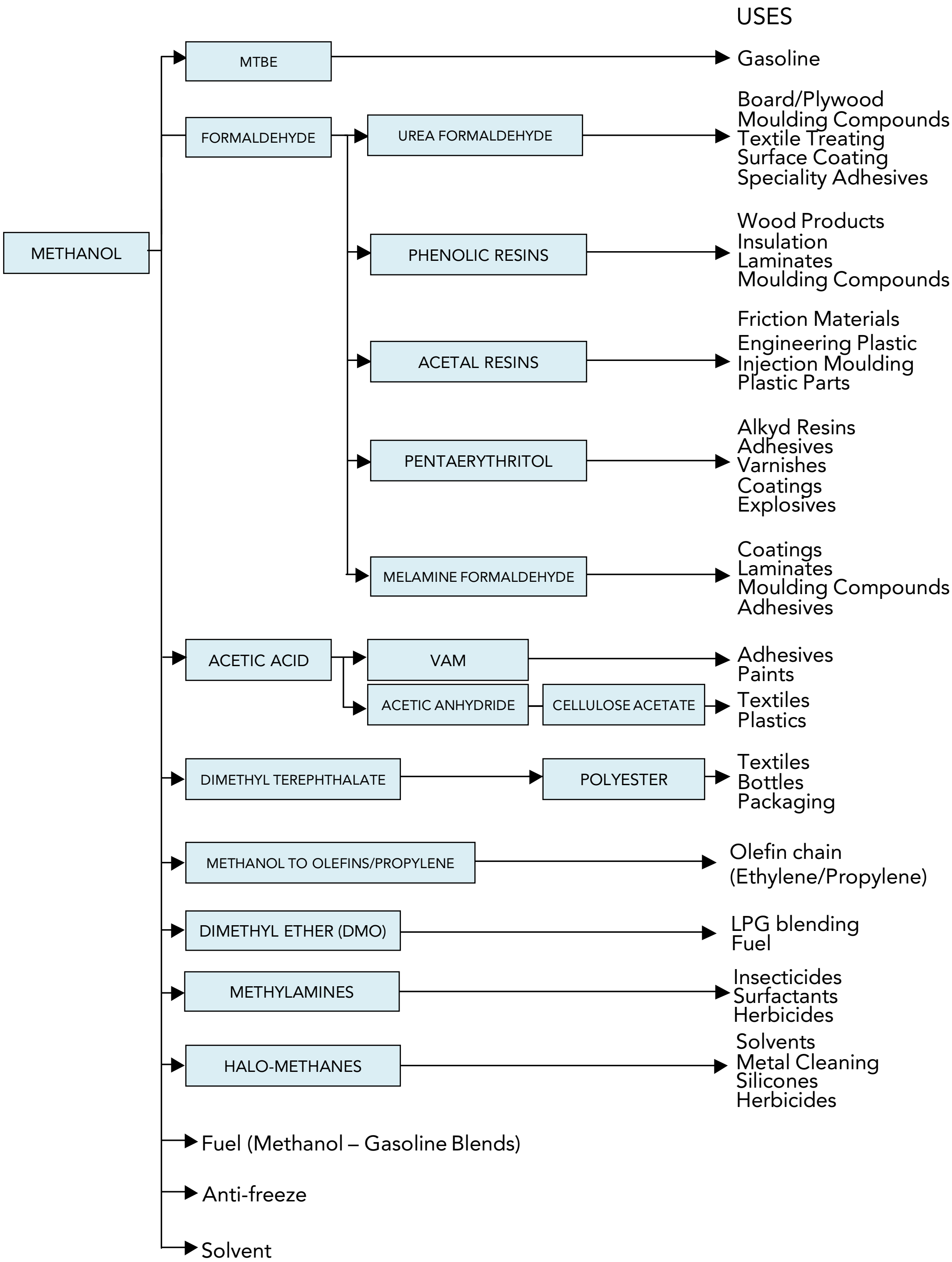
Figure F-10 Methanol Manufacturing Process from Natural Gas



Methanol is used to make other chemical products or used as a fuel. Its liquid state under normal conditions offers transportation advantages versus gas and LNG, although it has a relatively low energy density in comparison to other liquid hydrocarbons.

As shown in Figure F-11 overleaf, methanol has two major derivatives; MTBE and formaldehyde. MTBE is almost exclusively used as a gasoline component in order to increase its octane rating. Formaldehyde is primarily used to produce a range of resins used in wood products, insulation, moulding, etc. Other methanol derivatives include acetic acid, methylamines and halo-methanes, although many of the last are under threat due to concerns about global warming, toxicity and ozone depletion.

Figure F-11 Methanol Product Chain



The global methanol market is discussed in detail in Appendix H.

"Typical" world-scale plant parameters are as follows:

- Capacity: ~1.3 MMt/y of methanol
- Gas feedstock consumption: ~95 MMcf/d / 0.65 Tcf over 20 years
- Capital costs: ~$1 billion

The dominant methanol technology providers are:

- Johnson Matthey (JM) Catalysts is the dominant provider of methanol technology with around 50% of the global market.
  - JM Catalysts invented the Low Pressure Methanol process in the 1960s and this technology has been a cornerstone of the development of the methanol industry.
  - JM Catalysts' methanol technologies are licensed by its subsidiary, Davy Process Technologies, which it acquired in 2006. Davy Process Technologies has licensed technologies for plants with single stream capacities of up to 1.8 MMt/y.
- Lurgi is the second largest provider of methanol technologies with over 30% of the global market.
  - The Atlas methanol plant in Trinidad, which was developed by Methanex using Lurgi technology and started up in 2004, is one of the largest single train methanol plants in the world, with an annual production capacity of ~1.8 MMt/y.
  - Lurgi was also the EPC contractor for the Atlas methanol plant.

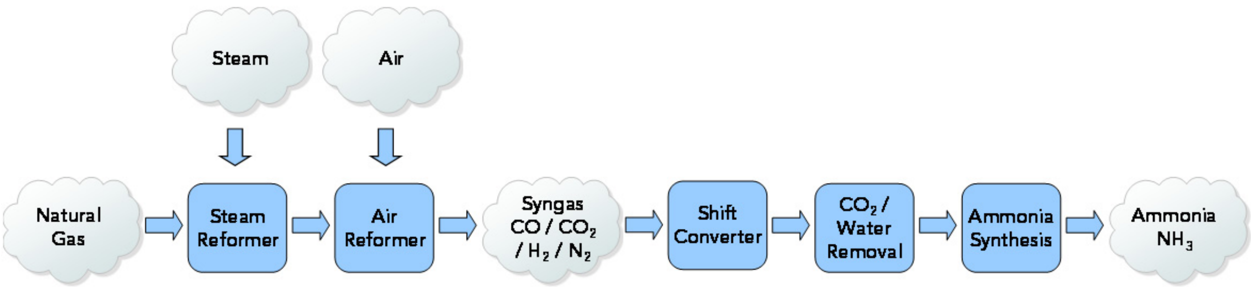
F.5.2 Ammonia / Urea

F.5.2.1 Ammonia

As per methanol, ammonia (NH_3) production from natural gas involves the reforming of the gas into syngas. As nitrogen must be added to the gas for ammonia synthesis, the general approach is to add air and allow internal combustion to supply part of the required heat in an air reformer after the initial steam reformer. A water gas shift reaction is utilised to form additional CO_2 and H_2 from CO and water.

CO_2 and water are then removed before the remaining nitrogen and hydrogen can be synthesised to form ammonia, as shown in Figure F-12 below.

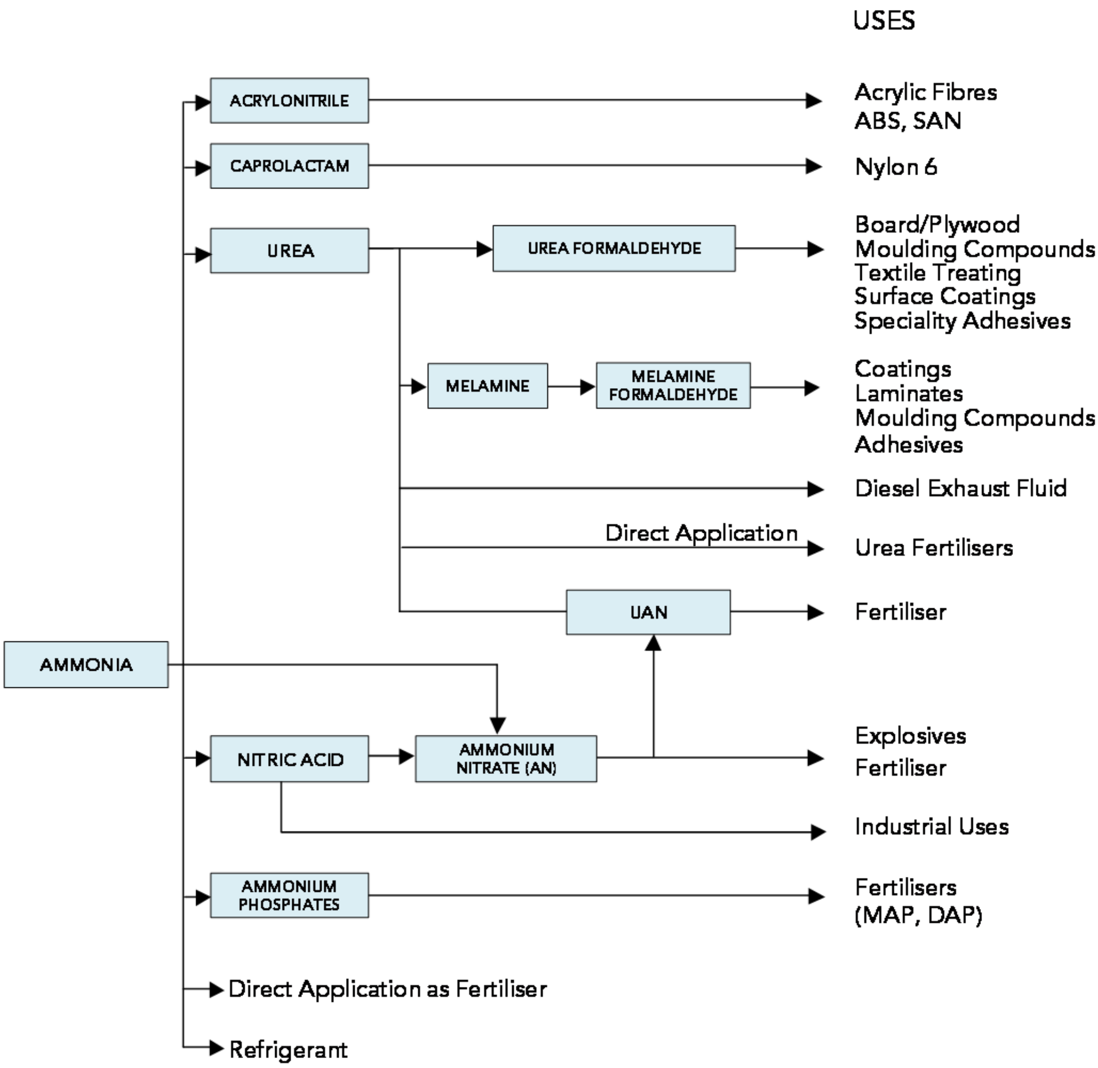
Figure F-12 Ammonia Manufacturing Process from Natural Gas



The main ammonia feedstock globally is natural gas, but it is also produced from liquid or solid fuel, for example in China where there is very large and growing ammonia production based on coal, while in India, naphtha is widely used.

Anhydrous ammonia is consumed principally in fertiliser applications, in some cases applied directly to soil in its pure form, although mainly used in the production of other solid or liquid fertilisers such as urea, ammonium nitrate (AN) and diammonium phosphate (DAP), as shown in the figure below. Anhydrous ammonia is gaseous at ambient temperature, and therefore is stored in cryogenic facilities as a liquid. Storage and transfer in such forms has high associated costs, and conversion to solid fertiliser allows lower logistical costs in distribution and usage. Ammonia is also consumed in numerous chemical and industrial applications such as production of acrylonitrile, caprolactam, aniline and nitrate based explosives, and in aqueous solution as a solvent.

Figure F-13 Ammonia/Urea Product Chain

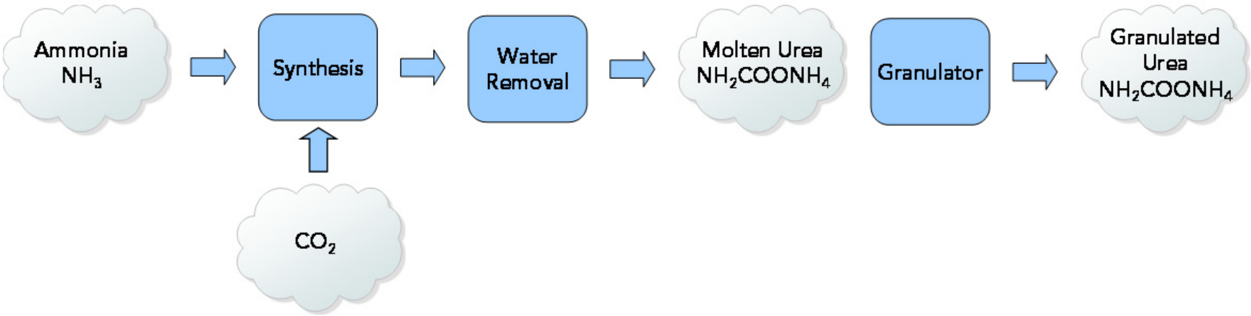


The global ammonia market is discussed in detail in Appendix H.

F.5.2.2 Urea

Urea ($CO(NH_2)_2$) is a solid which is produced from the reaction of ammonia with CO_2, as shown in the figure below. Ammonia and CO_2 are synthesised to form ammonium carbamate, which is in turn partly dehydrated before excess water is removed to form molten urea. This is processed either through a prilling tower or urea granulator to produce solid urea for shipment.

Figure F-14 Urea Manufacturing Process



Urea is usually produced adjacent to/integrated with ammonia production as ammonia production produces CO_2 as a byproduct. Many facilities can switch between the production of ammonia and urea depending on prevailing global prices.

Urea can be used alone for fertiliser use, or combined with other phosphate and potash fertilisers in NPK blends. It is also a constituent of UAN along with ammonium nitrate, which T&T exports in solution form. As shown in Figure F-13, there are several chemical and industrial uses for urea. The main uses are in urea-formaldehyde resins and melamine which are used in furniture and building applications.

F.5.2.3 Plant Parameters / Technology

"Typical" world-scale plant parameters are as follows:

- Capacity: ~0.75 MMt/y of ammonia feeding ~1.3 MMt/y of urea
- Gas feedstock consumption: ~80 MMcf/d / 0.55 Tcf over 20 years
- Capital costs: ~$1.4 billion

Historically, KBR, Uhde and Haldor Topsøe have been the main technology licensors for greenfield ammonia plants.

- KBR is a leading supplier of ammonia process technologies and EPC contractor to the fertiliser industries. The majority of its recent plants have been in the range of 2,000 t/d of ammonia production capacity.
- Uhde has been involved in the design and construction of ammonia plants since the 1920s and is the third largest licensor of ammonia production technology. Uhde's ammonia technology is utilised in the SAFCO plant at Al Jubail, Saudi Arabia, which with a production capacity of 3,300 t/d is one the largest ammonia plants in the world. Designs are in place for over 4,000 t/d.
- Topsøe is the market leader and technology provider for around 50% of new ammonia plants. It has developed designs for plants of up to 5,000 t/d capacity. However, Engro in

Pakistan with a nominal capacity of 2,200 t/d is the largest operating grassroots ammonia plant designed by Topsøe.

The stripping processes offered by Snamprogetti, Stamicarbon and Toyo Engineering are the main processes currently used for the production of urea. Snamprogetti and Stamicarbon have historically been the market leaders with a combined market share of around 90%.

- Snamprogetti is a leading urea technology provider, with over 40% of the global market. The first industrial plant utilising its ammonia stripping technology was put into operation in 1971. Since then more than 100 urea plants based on this technology have been implemented. The technology has been implemented in plants of close to 4,000 t/d capacity, although designs are claimed for up to 5,000 t/d.
- Stamicarbon is the technology licensing arm of Maire Tecnimont, which purchased the company from DSM in 2009. Its ammonia stripping technology is a leader in urea production, with over 40% of the global market. The technology is in operation in over 200 plants with maximum capacities in excess of 3,000 t/d. Stamicarbon's mega-plant concept is designed for up to 4,500 t/d capacity.

F.6 SUMMARY OF THE MAIN GAS UTILISATION OPTIONS

LNG is significantly the largest utilisation option in terms of product output and reserves required. A single train 5.5 MMt/y LNG plant will require 5.2 Tcf of reserves compared to 0.65 Tcf and 0.55 Tcf required by world scale methanol and ammonia/urea plants.

A summary of the estimated size, cost and gas consumption parameters for the main gas utilisation options detailed in this section, considering new world-scale plants, is included in the table below:

Table F-4 Summary of the Main Gas Utilisation Options

	Power Generation	Conventional LNG	Large FLNG	Small FLNG	Methanol	Ammonia / Urea
World-scale plant size	1,000 MW	5 MMt/y	3.6 MMt/y	1.5 MMt/y	1.3 MMt/y	0.75 MMt/y A 1.3 MMt/y U
Approx. Capital Cost (US$ bn)	1.0	5.0	5.5	2.5	1.0	1.4
Gas Consumption (MMcf/d)	150	770	550	240	95	80
Capital Intensity (US$/cf/d)	6.66	6.49	10	10.42	10.52	17.5
Gas Reserves required	1.0	5.2	3.8	1.6	0.65	0.55

LNG production benefits from economies of scale. The capital intensity, the amount of money that needs to be invested to process a unit of gas, is lower than for gas based petrochemicals, although FLNG is comparable.

F.7 ECONOMIC ANALYSIS OF GAS UTILISATION OPTIONS

An analysis was undertaken to determine the relative economic attractiveness of the following gas utilisation options, if new world-scale capacity was to be developed in T&T:

- Ammonia
- Methanol
- LNG
- Power
- DRI/EAF Steel

The analysis considered capital cost and operating cost estimates drawn from Poten's project database, and was carried out for three cases: Base Case, Low Case and High Case. The market assumptions are shown in the table below. For the LNG option, three markets were analysed: Asia, Europe and the US. The project life for each option was assumed to be 20 years and a discount rate of 12% was used in the evaluation of all projects. The profit tax rate was assumed to be 35% with straight line depreciation over 10 years. The projects were all assumed to be project financed on the same basis, 70:30 Debt Equity split for a term of 8 years.

Figure F-15 Market Assumptions for Economic Modelling

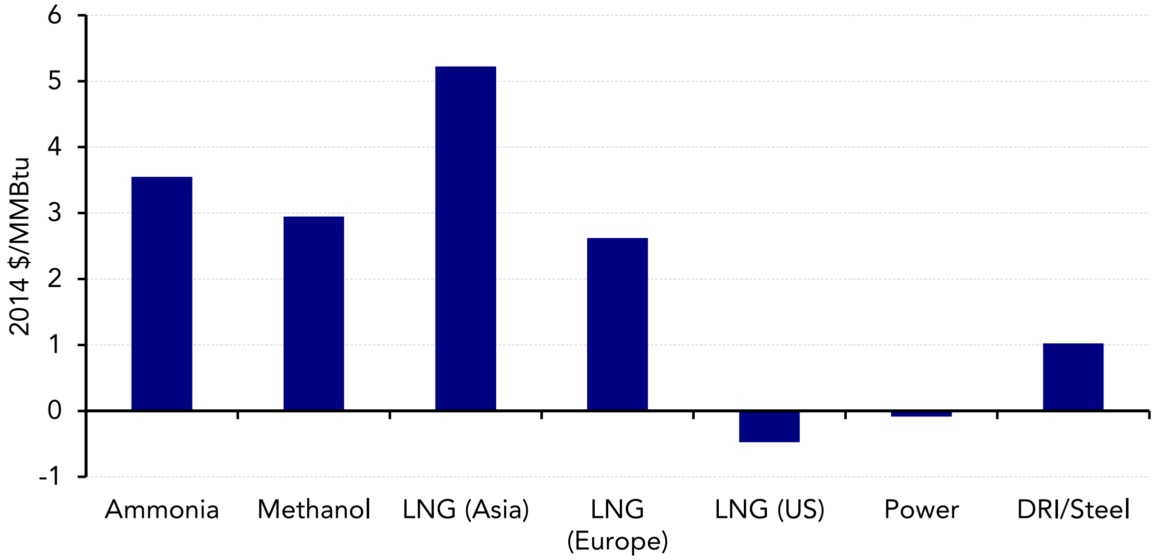
	Base Case	High Case	Low Case
Oil ($/bbl)	75	100	50
HH ($/MMBtu)	4	3	6
NBP ($/MMBtu)	7.5	9	6
Asia LNG ($/MMBtu)	13% Oil +$1	13% Oil +$1	13% Oil +$1
Ammonia ($/tonne)	Coal and oil-linked formula	Coal and oil-linked formula	Coal and oil-linked formula
Methanol ($/tonne)	Oil-linked formula	Oil-linked formula	Oil-linked formula
Steel ($/tonne)	510	590	460
Coal ($/tonne)	70	90	50
Power Price ($/kWh)	0.03	0.04	0.02

The analysis determined the netback price of gas that T&T would receive at the plant inlet for gas utilised in each of the options considered, taking into account transportation costs, and in the case of LNG the regasification cost. For LNG supply to Asia it was assumed that the Panama Canal would be used.

Overall, the analysis showed that for the Base Case LNG delivery to Asia has the highest netback gas price, at over $5/MMBtu. Ammonia and methanol have relatively high netbacks at $3.5/MMBtu and $3/MMBtu respectively. LNG sold to Europe gave a netback price of ~$2.5/MMBtu. Steel provides a netback of around $1/MMBtu. LNG sold in the US and power sold at $0.03/kWh both give negative netback prices, i.e. they destroy value.

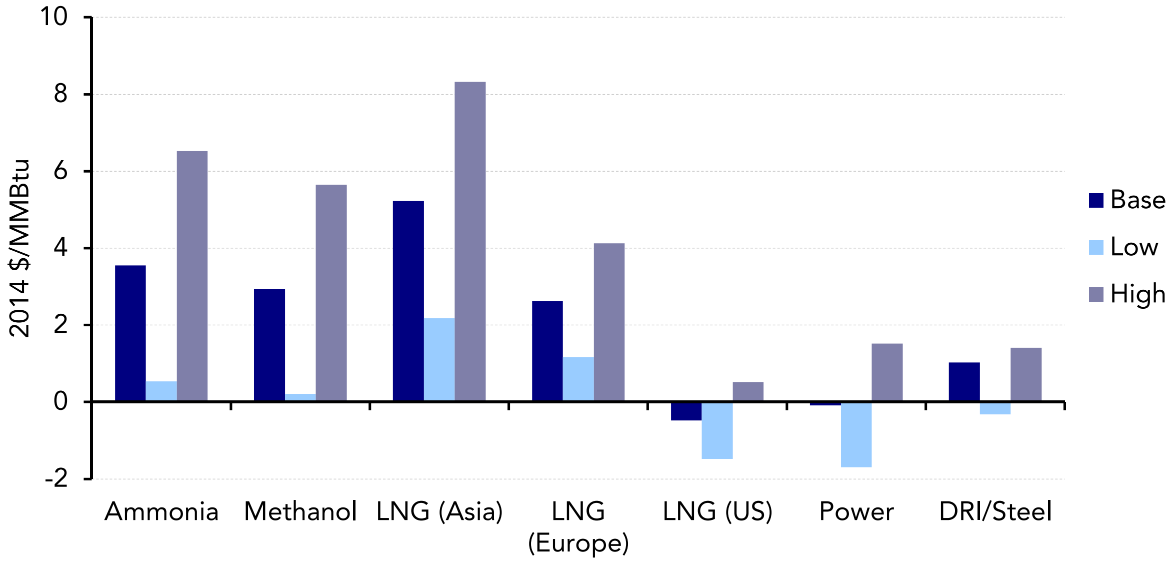
The results of the netback analysis are shown in the figure below:

Figure F-16 Gas Utilisation Options - Estimated Netback Gas Prices – Base Case



Sensitivity analysis showed that LNG sales to Asia and Europe, methanol and ammonia would all provide positive netbacks under the Low Case. Steel, power and LNG sales to the US all provide negative netbacks in the Low Case, as shown below.

Figure F-17 Gas Utilisation Options - Estimated Netback Gas Prices – Sensitivity Case



F.8 OTHER PETROCHEMICALS

F.8.1 Ethane Derivatives

Ethane has, in its raw form, limited value and if it is only available in small quantities it is simply left in the natural gas stream. The real value of ethane, if sufficient volumes are available, is in cracking it to ethylene for the manufacture of a range of petrochemicals, as shown in Figure F-18. Ethane is typically the most competitive feedstock for olefin petrochemicals.

Polymers represent the major end use for ethylene. Polymers are defined as long chain, high molecular weight chemical material. They have five major uses:

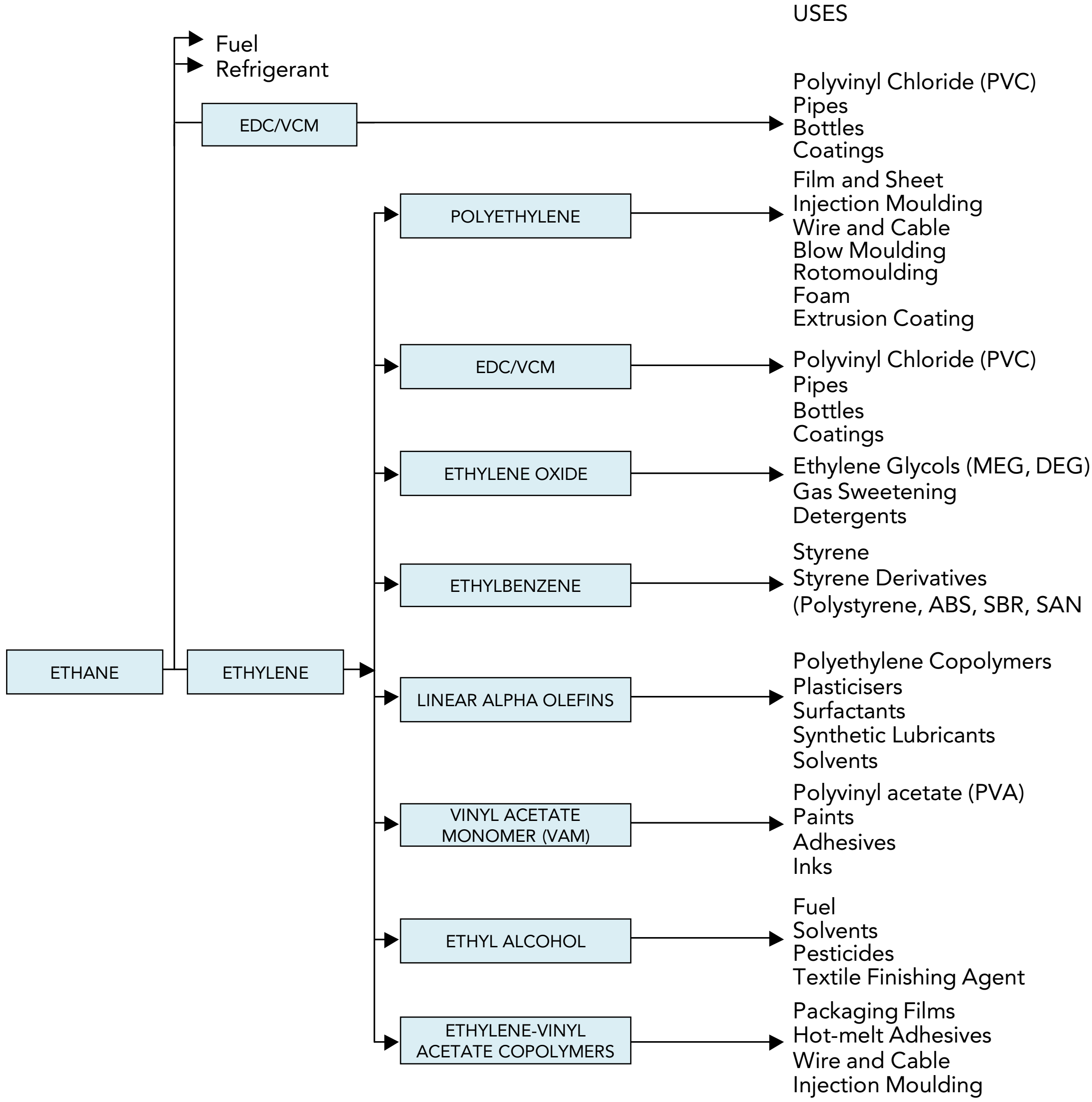
- Plastics – as polymer formed into shape by moulding, extrusions, foaming etc. Plastics provide the most important application for polymers.
- Fibres- polymers formed into threads or filaments.
- Elastomers – polymers that can be extended by application of force (e.g. pulling) and that return to their original shape when the force is released.
- Coatings and adhesives – coatings are polymers applied to a single surface, while adhesives bond two surfaces together.

Ethylene end markets are diverse, owing to the wide spectrum of derivatives. These end use markets include; wire and cable insulation, consumer, industrial and agricultural packaging, woven fabrics and assorted coverings; pipes, conduits and assorted construction materials, drums, jars, containers, bottles and racks to hold them, antifreeze, solvents and coatings.

The principal derivative of ethylene is polyethylene which is used in a wide range of applications, and then other polymers such as PVC and polystyrene. Other derivatives such as ethylene oxide open up a wide range of opportunities in the areas of surface-active molecules for use in detergents and cleaners, as well as the obvious use in polyester via conversion to glycol.

Vinyl acetate offers the opportunity to produce various ingredients for paints, adhesives and textiles whilst ethanol derivatives may be used as pesticides, solvents, anaesthetics, etc.

Figure F-18 Ethane/Ethylene Product Chain



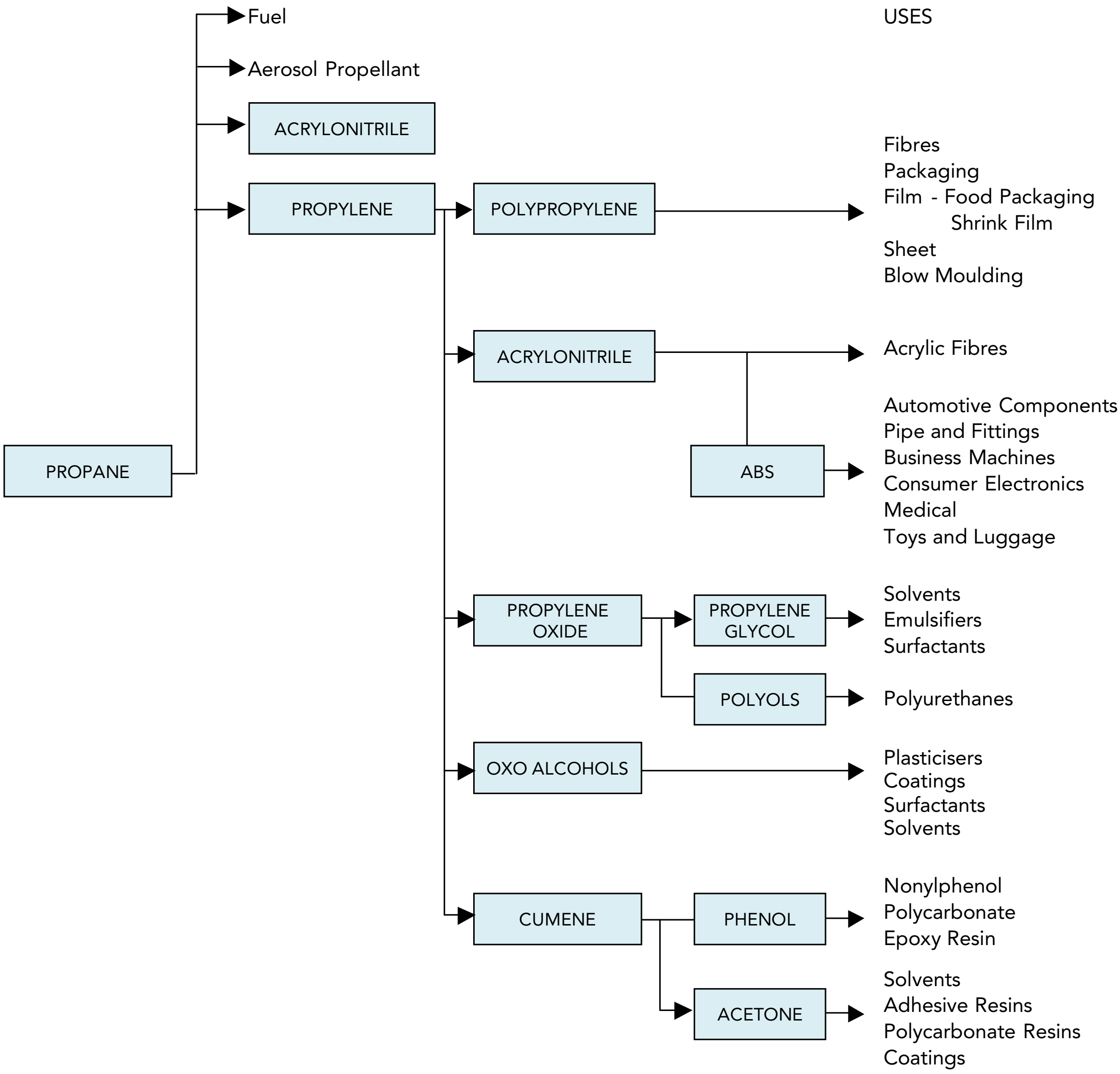
The production of EDC, VCM and PVC obviously requires chlorine. Whilst this is certainly feasible and only requires salt and electricity there is the question of what do to with the co-product caustic soda.

Finally production of vinyl acetate monomer requires acetic acid, which is mainly produced via methanol carbonylation. Methanol is already produced in T&T and carbon monoxide can be produced from natural gas. However, a world-scale acetic acid plant would produce excess acetic acid than that required for a world-scale vinyl acetate plant, which would mean that excess acetic acid production would need to be exported.

F.8.2 Propane Derivatives

Propane, together with butane, is readily disposable as LPG. The figure below shows the derivatives diagram for propane. There are few direct derivatives, with most requiring the molecule be made available for reaction by conversion to propylene.

Figure F-19 Propane/Propylene Product Chain



Polypropylene, which is a thermoplastic, is globally the most important propylene derivative. It is used to produce fibres, for packaging, for producing film and sheet, and in blow moulding. Acrylonitrile is also an important propylene derivative being primarily used in the product of acrylic fibres and ABS resins. It can also now be produced directly from propane.

Oxo-alcohols require syngas and this can be extracted from the steam reformer on an ammonia or methanol plant, assuming this is alongside or close to the oxo-alcohols plant. Clearly when considering some of these derivatives and some of the ethane based derivatives where syngas is a feed (e.g. the CO for methanol carbonylation to provide acetic acid for VAM) it is important to consider total syngas requirements to produce an optimised complex.

Propylene oxide (PO) may be produced via three routes:

- The chlorohydrin process which is not favoured any more for economic and safety reasons.
- The SMPO route. This co-produces styrene and PO from ethylbenzene and propylene.
- The MTBE route. This co-produces PO and TBA (tertiary butyl alcohol) from propylene and iso-butane. The TBA is dehydrated to yield iso-butylene which is reacted with methanol to give MTBE. The iso-butane may be separated from the mixed C4 stream produced from NGL separation.

However for the latter two cases, which are the only viable options, PO production cannot be considered in isolation.

Finally, production of cumene is dependent on the availability of benzene.

G.1 WORLD ECONOMIC OUTLOOK

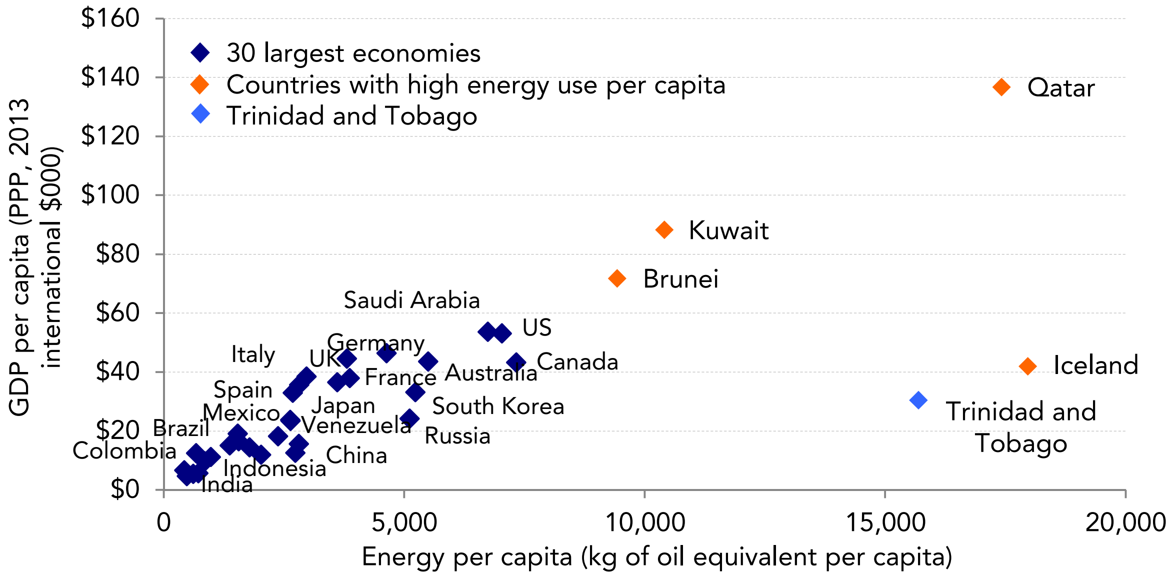
Following what had been more than a decade of sustained economic growth throughout the 1990s and into the first half of the last decade, the events of 2007-08 triggered a global economic crisis. This resulted in an extended period of economic decline and reduction in GDP around the world, otherwise referred to by the IMF as a "Global Recession", as well as a drop in international trade and a rise in unemployment. Years of fiscal and monetary policies geared towards stimulating growth in the global economy are starting to generate positive signs of recovery, and even sustained growth, within some of the world's largest economies, although economies such as the Eurozone continue to struggle. It is this recovery that forms the economic backdrop for the master plan period.

The markets for T&T's key export commodities including LNG, petrochemical products (methanol), fertilisers (ammonia/urea) and iron & steel are driven by the global economy. Growth in worldwide markets is a function of population and economic growth. Population growth results in increased consumption of energy, foodstuffs and basic materials while economic growth and the consequent improving living standards generates additional consumption.

G.1.1 GDP and Energy Consumption

Energy consumption is closely correlated to GDP as can be seen in the figure below. As GDP grows energy consumption grows but consumption growth tends to slow as GDP/capita passes US$30,000 per annum and in many developed countries consumption has levelled off at around 4,000 kg/per capita per annum. There are a many exceptions, notably the US, Canada and Saudi Arabia, where specific energy consumption is significantly higher that the norm.

Figure G-1 GDP and Energy Consumption
(source: World Bank)



Small energy-rich countries such as T&T tend to be outliers to this trend, as the energy per capita is much higher than for other countries with more diversified economies. The comparison with Brunei and Qatar is instructive as both of these economies are also highly dependent on gas exports, albeit with significantly smaller populations than T&T.

G.1.2 Current Trends in GDP

The global economy is slowly returning to more robust growth. The latest estimates from IMF (Jan 2015 update) show that the global economy grew by 3.3% in 2014. However, the pace of recovery remained different between regions and advanced/emergent economies. Growth in advanced economies stood at 1.8%, driven by a 2.4% increase in US GDP which outpaced lower growth in the Eurozone where the effects of the downturn remain stubborn, and in Japan where growth has remained low. Amongst other advanced economies, some comfort has come from the UK and Canada where growth has been solid at 2.4-2.6%. Output growth in emerging and developing economies stood at 4.4% in 2014, driven by Chinese and Indian GDP growths of 7.4% and 5.8% respectively. Growth for Latin America and the Caribbean is estimated at 1.3% for 2014.

Although partly offset by a boost from lower oil prices, negative factors including investment weakness due to lower expectations of medium-term growth in many advanced and emerging market economies have lowered global growth forecasts for 2015 and 2016 to 3.5% and 3.7% respectively. Growth in the US is projected to exceed 3.0% in 2015/16, with domestic demand supported by lower oil prices, more moderate fiscal adjustment, and continued support from an accommodative monetary policy stance, despite the projected gradual rise in interest rates. Euro area growth is also expected to be supported by lower oil prices, monetary policy easing and a more neutral fiscal policy stance, resulting in euro depreciation, tempered against weaker investment prospects and slower export growth, particularly to emerging markets.

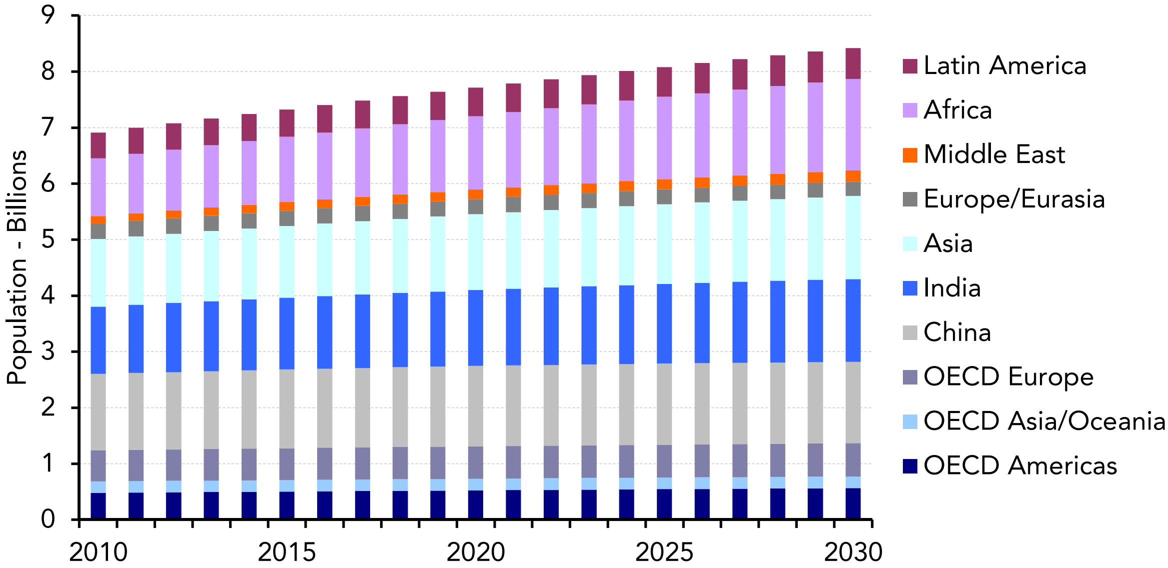
In emerging market and developing economies, growth is projected at 4.3% and 4.7% in 2015 and 2016 respectively, driven by stronger domestic demand as well as a recovery in export demand to advanced economies. China and India are projected lead the way with growth rates of around 6.5% p.a. average between 2015 and 2016. Latin American and Caribbean output is projected to rebound to 2.2% growth for 2015. Projections have been downgraded recently to reflect weak export performance and domestic policies which have negatively impacted investment confidence.

G.1.3 Basic Global Demand Drivers – Population

Demand for T&T's exports is also driven by global population expansion. According to the Medium Fertility scenario from United Nations, Department of Economic and Social Affairs (World Population Prospects), by 2030 the world population is expected to reach 8.43 billion people from an estimated 7.24 billion as of mid-2014.

Figure G-2 Projected Global Population

(source: UN Medium Fertility scenario - United Nations World Population Prospects)



Most of the growth to 2030 will be in developing countries. China's population is expected to peak at 1.45 billion around 2030, while India's population is expected to pass that of China around 2028. By 2035, China and India will be the world's largest and 3rd largest economies respectively, jointly accounting for about one-third of global population and GDP.

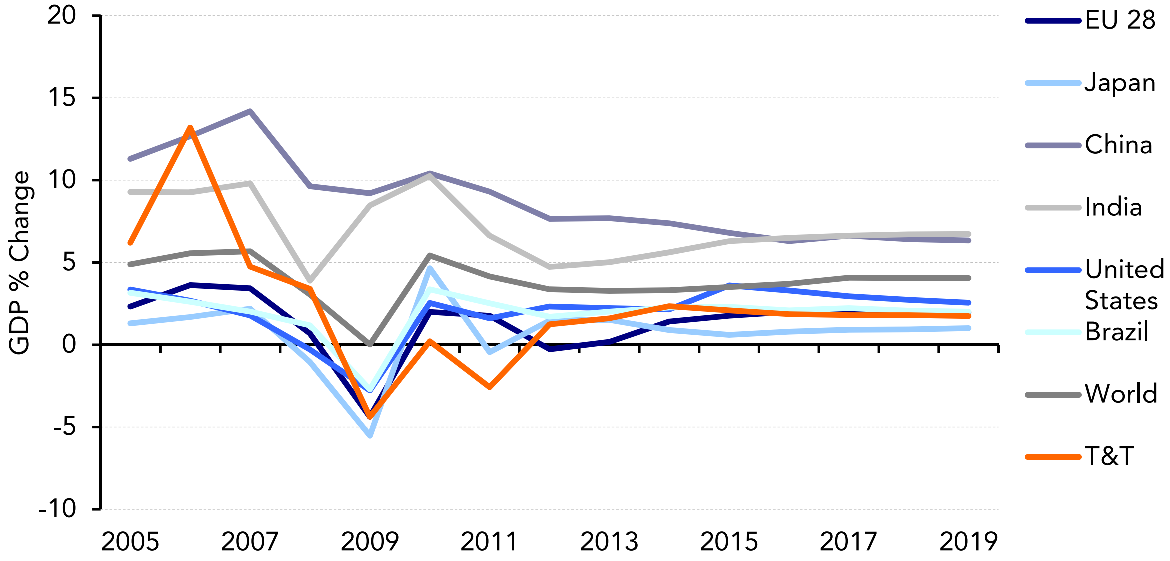
G.1.4 Medium-Term Outlook for GDP

Emerging market and developing economies are expected to continue to account for the bulk of global GDP growth. According to IMF projections, which are the basis for our commodity demand forecasts, medium-term global GDP growth (between 2017 and 2019) is expected to be slightly stronger than in 2014 at around 4.0% p.a. Growth rates are expected to be higher in developing countries, and in particular, growth in China and India is expected to be around 6.6-6.7% p.a. Growth in OECD economies is expected to be led by the US, at a rate of 2.9% p.a.

The main risk on the downside is a shift in sentiment and volatility in global financial markets, especially in emerging market economies, where lower oil prices have introduced vulnerabilities to oil exporters. On the upside, the boost to global GDP in advanced economies from lower oil prices could be greater. Stagnation and low inflation remain concerns in the euro area and in Japan.

Figure G-3 Projected Medium-Term GDP Growth

(% change, constant prices. source: IMF projections - World Economic Outlook, Oct 2014)

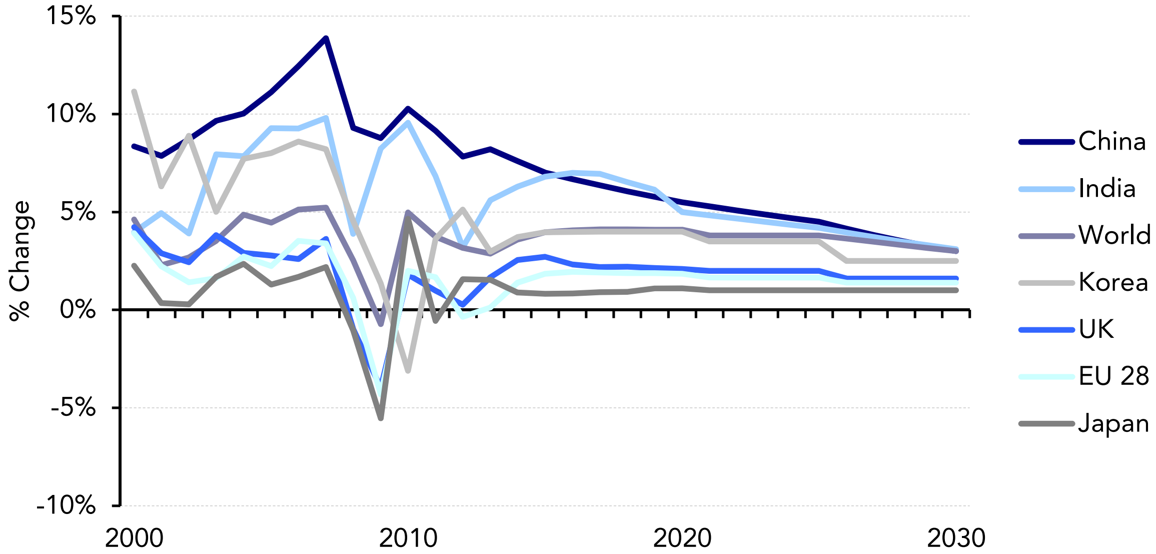


G.1.5 Long-Term Outlook for GDP

There are a number of trends that can be seen to guide global long-term economic growth:

- The composition of global output will continue to shift towards emerging economies as well as towards Asia. India and Indonesia are projected to surpass China to become the two fastest growing countries by 2020.
- While the slowdown in trend GDP growth is a feature of all developing countries, it is most marked in the case of China; from averaging 9-10% per annum since 2000, the average growth rate is set to roughly halve over the period 2014-30.
- Providing growth of the technology frontier continues at historical rates, average growth in OECD GDP per capita over the period to 2060 is projected to be similar to the 1½ per cent per annum experienced in the immediate pre-crisis period.
- With only a few major exceptions, the adverse effect of population ageing on labour utilisation in developed countries will be largely offset by rising labour force participation. Up until 2030, this is should be achieved in most countries through already legislated increases in pensionable age, the positive effect of increased education and trend increases in female participation.
- Average real long-term interest rates are projected by OEC to rise by around 1.5% percentage points over the next 4-5 years as output gaps close and policy rates normalise. Beyond this, supported by fiscal consolidation in OECD countries and a compositional shift in the share of world output towards high-saving non-OECD countries, no strong upward pressures on interest rates are expected until well after 2030.

Figure G-4 Projected Longer-Term GDP Growth



Our outlook for long-term GDP growth shows a lower and converging path as GDP growth moderates and the regions converge. Growth in the largest OECD countries will slowly decline as these economies are already advanced and mature while GDP growth rates in China and India, which currently are seeing rapid economic expansion, will trend lower as these economies become developed. Long-term global GDP will follow the same trends as in India and China as the economies of these countries will have an increasing contribution to and influence on global GDP, and our projections show global GDP growth converging with Indian and Chinese growth rates at around 3.0% p.a. by 2030.

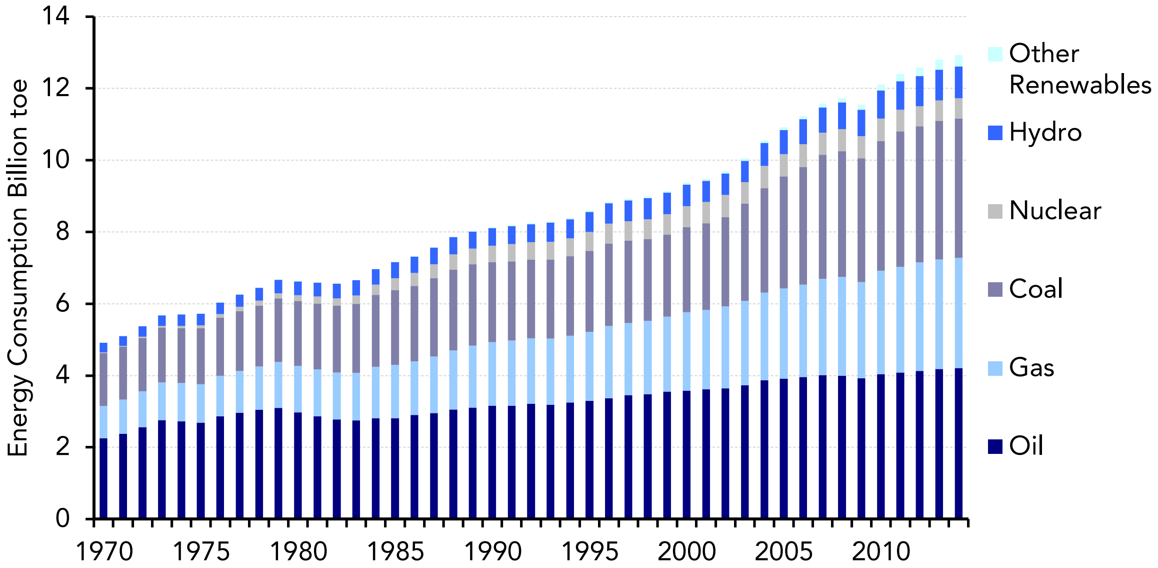
G.2 GLOBAL ENERGY TRENDS

G.2.1 Patterns of Energy Supply and Demand

World energy consumption, as measured by Total Primary Energy Supply (TPES), grew by some 32% over the period from 2001 to 2013: a compound annual growth rate (CAGR) of 2.6% p.a. The majority of the growth in world energy consumption was in developing economies, with China and India alone accounting for 65% of the total growth in consumption in the 2001-2012 period. China became the world's largest energy consuming country in 2010, overtaking the USA.

Figure G-5 Total Primary Energy Supply Growth

(Source: BP Statistical Review of World Energy 2015)



In terms of energy mix, fossil fuels still provide the majority of global energy needs, accounting for 86% of global TPES in 2014. Renewable energy made up 9.3% of TPES, with hydro-electricity making up 73% of the total renewable contribution, while nuclear accounted for 4.4% of TPES.

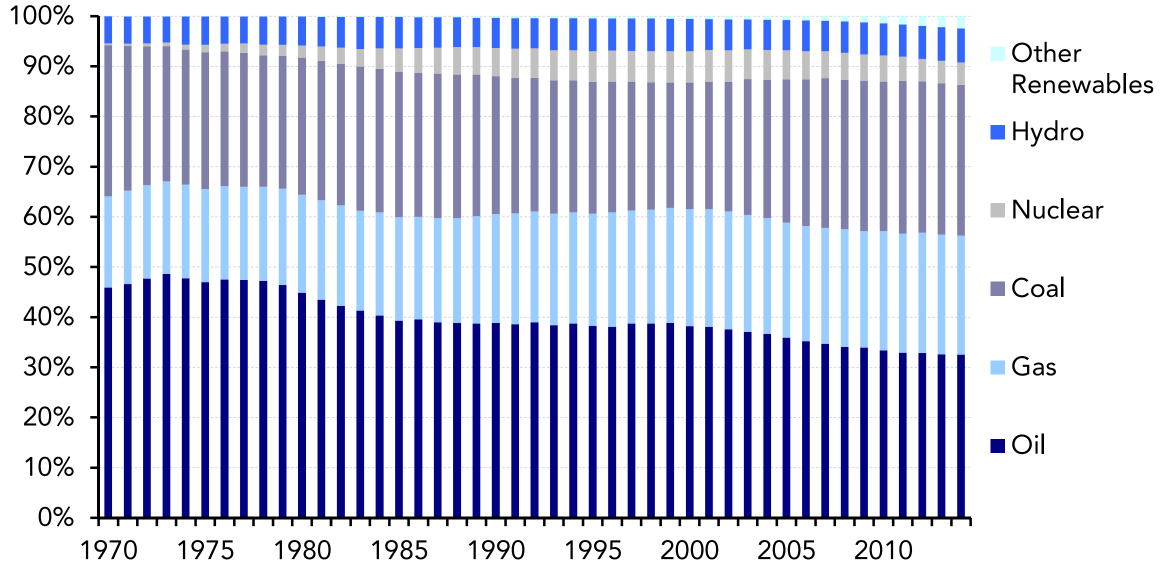
Although absolute consumption levels have continued to increase, oil's share of TPES decreased significantly from the 1973 oil shock through to the mid-1980s, as shown in the figure below, and has continued to decline slowly since. Oil-fired power generation has been substituted by coal-fired and gas-fired plant, which has been more economical. Oil is now mainly consumed in the transportation sectors. Gas has been the main source of energy displacing oil.

Coal was the fastest-growing of the fossil fuels over the 2000-2014 period, with total coal consumption increasing by 64% over that timeframe. Gas and oil consumption increased by 41% and 18% respectively in the same period. Nuclear power generation fell by around 2% from 2000 to 2014.

World carbon dioxide emissions grew by 39% between 2000 and 2014, increasing more rapidly than TPES as coal increased its share of the TPES from 25% in 2000 to 30% in 2014.

Figure G-6 Historical Share of Total Primary Energy Supply

(Source: BP Statistical Review of World Energy 2015)



Renewable energy sources such as solar and wind power have grown significantly in the last decade but make up only a small portion of overall TPES at ~2.5% in 2014.

G.2.2 Key Energy Sector Trends

The global energy sector has seen some very significant developments over the last decade. Some of the most important of these are summarised below.

- Growth in the developing economies, particularly India and China, has been the most important factor shaping the global energy demand picture. Growth in energy consumption is directly correlated to GDP growth, but the impact of developing countries is given even greater weight by the fact that these economies are more energy intensive than the majority of the developed economies, i.e. they require a higher input of energy to generate a given unit of GDP growth. As China and India are highly dependent on coal as an energy source (making up 68.5% and 52.9% of TPES in the two countries respectively), this has been the main contributor to coal's recent relatively high growth.
- The global recession and the patchy recovery from it have had consequent effects on energy demand. While non-OECD primary energy consumption grew by 4.5% in 2012, OECD consumption registered a drop of 0.9%, and EU primary energy consumption fell by 0.8% in 2012.
- Oil prices increased by over 250% on an annual basis from 2001 to 2013 in real terms, reaching or exceeding their previous peak reached in 1979 in the wake of the Iranian revolution. Several factors have contributed to this escalation, including increased oil demand in Asia, and increasing costs of new production, which itself has been fuelled by increasing demand in Asia for raw materials as well as engineering and construction resources. Subsequently in the latter part of 2014 and early 2015 we have seen a major fall in the price of oil as demand weakened in the face of overabundant supply not least from shale production in the US.

- The shale revolution in the US has given the country access to growing indigenous hydrocarbon liquids production and abundant supplies of cheap gas, with the US Henry Hub price having fallen from a peak of over US$12/MMBtu in June 2008 to an average of US$2.75/MMBtu in 2013 and only slowly increasing to US$3.48/MMBtu at the end of 2014. At this level US gas prices were around 20% of international crude oil prices in thermal terms, and competitive with coal. The shale gas developments, and also the increasing production of shale (or tight) oil, has not only given the US an enhanced degree of energy independence, but has also revived the fortunes of certain industries such as petrochemicals, which had previously migrated to other low energy cost regions. It has also positioned the US as a potential future LNG exporter (having previously been considered to be likely to be a major LNG importer from the mid-2000s).

G.2.3 Expected Future Energy Consumption

TPES is expected to grow significantly to 2025 with the major increases from renewables, natural gas and coal. Poten's forecasts are compared to those of various agencies in the table overleaf.

The projected future growth rates are lower than those experienced in the last decade as the world is leaving a phase of very high energy consumption growth, driven by the industrialisation and electrification of the developing world, notably China. The 2003-2013 decade recorded the largest ever growth of energy consumption in volume terms over any ten-year period, and this is unlikely to be surpassed in our timeframe. That said, there is a clear long-run shift in energy growth from the developed to the developing world with virtually all (95%) of the projected growth in the developing world.

Poten forecasts gas supply growth of around 32% from 2013 (IEA figures) to 2025. Poten expects gas to overtake oil as the dominant fuel by around 2030 for OECD countries but for non-OECD countries gas is expected to remain in third place, behind coal and oil, beyond this point in time. The fastest growing gas consuming sector is expected to be transport, but this is from a small base. In volume terms the largest growth is expected to come from traditional sectors; industry and power. Global gas supply is expected to grow to around 149 Tcf/y by 2025 (3,791 MTOE).

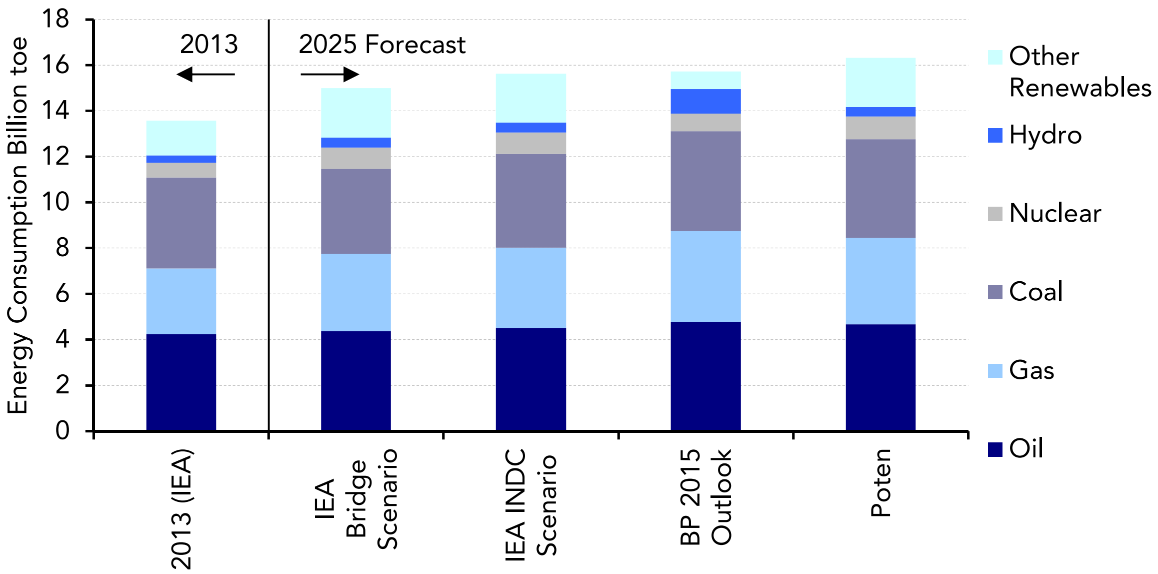
Table G-1 Projected TPES at 2025 (MTOE)

(Source: IEA WEO2015 Special Report, EIA, BP Statistical Review of World Energy 2015)

Energy Source	IEA 2013	IEA Bridge Scenario	IEA INDC Scenario	BP 2015 Outlook	Poten
Oil	4,235	4,373	4,519	4,777	4,666
Natural Gas	2,880	3,389	3,508	3,964	3,791
Coal	3,973	3,704	4,094	4,366	4,307
Nuclear Energy	646	938	939	780	985
Hydroelectricity	320	434	425	1,073	420
Other Renewables	1,525	2,161	2,134	755	2,151
Total	13,579	14,999	15,619	15,715	16,319
Overall Energy Growth, 2014-2025		10.5%	15.0%	15.7%	20.2%
Natural Gas Growth, 2013-2025		17.7%	21.8%	37.6%	31.6%

Figure G-7 Projected TPES Growth to 2025

(Source: IEA WEO2015 Special Report, BP Statistical Review of World Energy 2015)



H.1 GLOBAL NATURAL GAS MARKETS

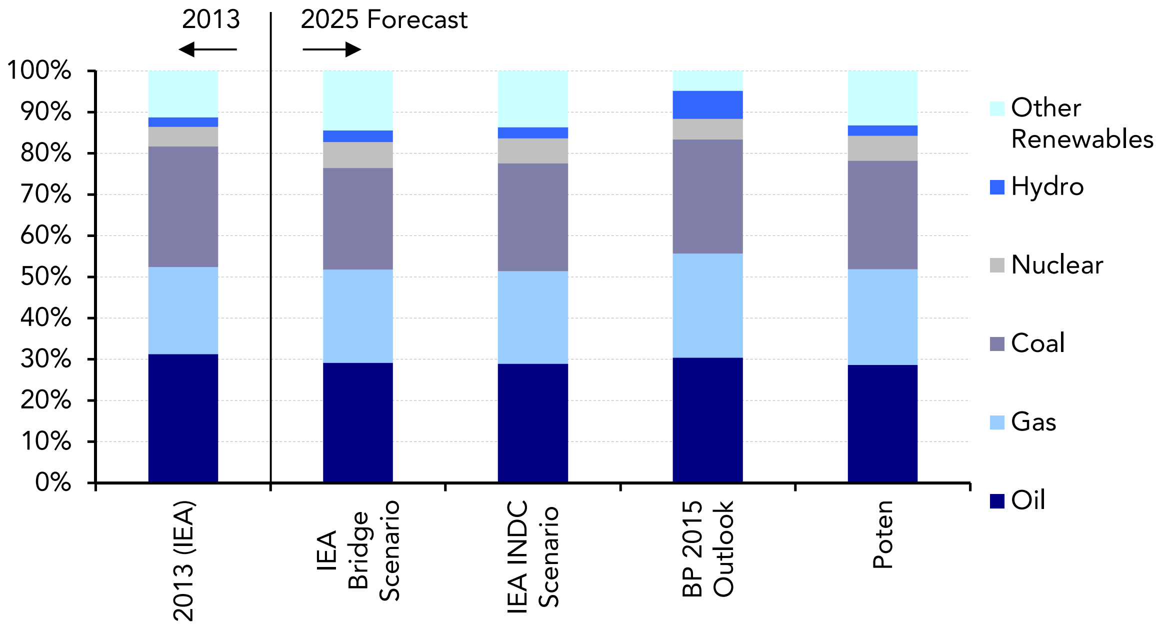
H.1.1 Overview

Natural gas is unique in the global energy mix: it is a globally abundant and commercially viable hydrocarbon combining the reliability of other fossil fuels such as coal and oil with a relatively low carbon footprint and low emissions. Combined cycle gas turbines (CCGTs) represent the most efficient power generation technologies, in terms of production and capital cost requirements, with a flexibility that makes gas an ideal back-up solution for the intermittence of renewables, such as wind or solar.

Natural gas is projected to expand its share of the global TPES, a trend that is already underway in many key regions. Poten's base projection shows the percentage share of TPES held by natural gas growing to 23% by 2025 from 21% in 2013. These figures are in line with the IEA long-term view which has natural gas increasing its share of global TPES in all its scenarios.

Figure H-1 Projected Global Energy Mix at 2025

(source: IEA WEO2015 Special Report, BP Statistical Review of World Energy 2015)



Natural gas supplies are often surplus to local needs and located far from demand centres. As more remote resources are developed inter-regional natural gas trade will increase. While moving natural gas by pipeline is generally the most economical means of short to medium-haul transportation, a lack of adequate pipeline infrastructure, geographic impracticality of pipelines in some cases and lengthening trade routes have promoted the growth of LNG trade. The cost and logistical difficulty of trading gas across borders mean that natural gas markets are much less integrated than oil markets. Shipping or transporting natural gas requires either costly pipeline networks or liquefaction infrastructure and equipment, including dedicated vessels, and then regasification at the destination.

H.1.2 Natural Gas Reserves

As at the end of 2014 global gas reserves stood at 6,606 Tcf. Key contributors to the total global reserves figure are shown in the table below and figure overleaf.

Table H-1 Largest Gas Reserves by Country

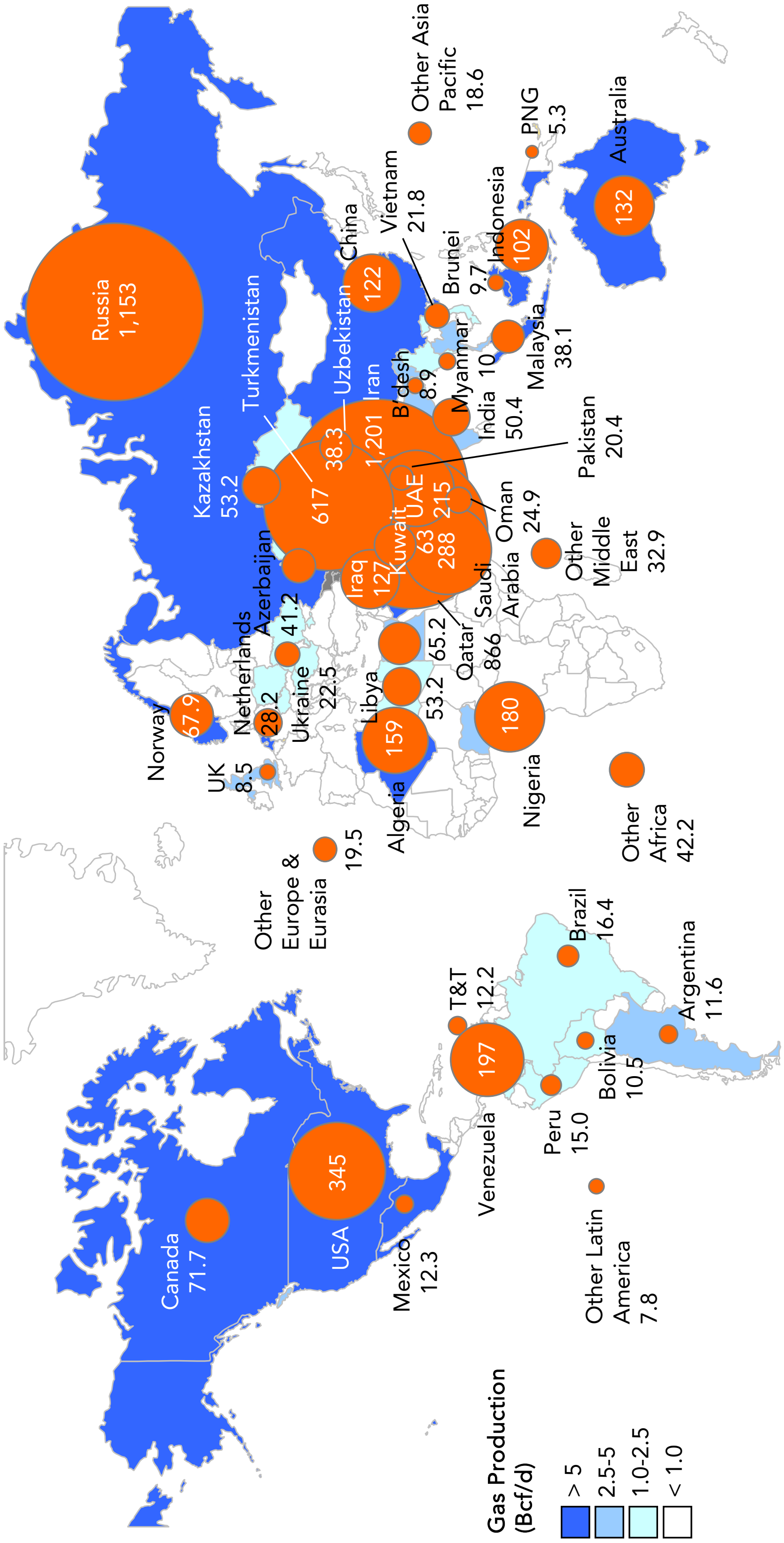
(Source: BP Statistical Review of World Energy 2015)

Country	Proven Reserves (Tcf)	2014 Production (Bcf/d)	R/P ratio (years)
Iran	1,201	16.7	>100
Russia	1,153	56.0	56.4
Qatar	866	17.1	>100
Turkmenistan	617	6.7	>100
USA	345	70.5	13.4
Saudi Arabia	288	10.5	75.4
UAE	215	5.6	>100
Venezuela	197	2.8	>100
Nigeria	180	3.7	>100
Algeria	159	8.1	54.1
Australia	132	5.3	67.6
Iraq	127	0.1	>100
China	122	13.0	25.7
Indonesia	102	7.1	39.2
T&T	12.2	4.1	8.2

Although the world’s gas reserves are not as geographically concentrated as crude oil, nearly 80% of the world's total proven natural gas reserves are located in ten countries:

- **Iran** presently holds the world's largest natural gas reserves. Its proven reserves as of the end of 2014 stood at 1,201 Tcf. Most of these reserves remain undeveloped due to international sanctions and delays in field development. More than 60% of Iran's reserves are located offshore and non-associated fields account for around 80% of the proven reserves base. South Pars is the largest gas field comprising ~27% of Iran's total proved natural gas reserves and ~35% of the country's natural gas output. North Pars, Kish and Kangan are the other major natural gas fields in Iran. Natural gas production in 2014 was ~16.7 Bcf/d.
- **Russia** holds 1,153 Tcf of proven gas reserves as the end of 2014. More than half of Russia's gas reserves are located in Siberia. Three of the major Siberian fields, namely Yamburg, Urengoy and Medvezh'ye, account for approximately 45% of the country's gas reserves. The majority of the country's reserves under development and production are located in the Nadym-Pur-Taz (NPT) region of upper Western Siberia. Russia produced around 56 Bcf/d of natural gas in 2014.

Figure H-2 Global Proven Gas Reserves
(source: BP Statistical Review of World Energy 2015)



- **Qatar** holds the third largest natural gas reserves in the world, estimated at 866 Tcf as of the end of 2014, accounting for around 13% of the global total. The vast majority of the country's reserves are located in the giant offshore North Field, which covers an area almost equivalent to Qatar itself. The North Field is the world's largest non-associated gas field and is the main source of Qatar's natural gas production. Natural gas production in 2014 was 17.1 Bcf/d, much of which fed the QatarGas and RasGas LNG plants.
- **Turkmenistan** holds the fourth largest natural gas reserves in the world, estimated at 617 Tcf as of the end of 2014. Turkmenistan, however, faces challenges in developing its gas reserves because of the remoteness of end-use markets, its land-locked state and a lack of sufficient pipeline infrastructure. Most of Turkmenistan's proven gas reserves are located in the Amu Darya basin in the south east and in the Murgab South Caspian basins in the western part of the country. The Dauletabad field in the Amu Darya basin, with estimated gas reserves of 60 Tcf, is one of the largest and oldest gas fields in Turkmenistan. The South Yolotan area in the eastern region of Turkmenistan also contains significant gas reserves. Turkmenistan produced 6.7 Bcf/d of natural gas in 2014.
- The **USA** ranks as the fifth largest, holding 345 Tcf of proven natural gas as of the end of 2014. US proven reserves have steadily increased since 1999 with the expansion of exploration and development activities in its shale formations. The US is currently the world's largest producer and consumer of natural gas. It produced 70.5 Bcf/d of natural gas in 2014 (there is a more extensive discussion on North American shale gas later in this Appendix).
- **Saudi Arabia** holds the sixth largest natural gas reserves in the world. Its estimated proven natural gas reserves as of the end of 2014 stood at 288 Tcf, including its share of gas reserves in the Saudi-Kuwait Neutral Zone. Associated gas at the giant oil fields, such as the Ghawar onshore field and the offshore fields Safaniya and Zuluf, account for about 57% of the country's proven gas reserves. Natural gas production in Saudi Arabia in 2014 stood at 10.5 Bcf/d. The country does not import or export natural gas. Its entire gas output is consumed domestically.
- The **UAE** has proven natural gas reserves as of the end of 2014 of 215 Tcf. Despite the large gas reserves the country imports natural gas, primarily from Qatar, because around 30% of the UAE's gas output is re-injected into oil fields. The UAE's natural gas production in 2014 was 5.6 Bcf/d.
- **Venezuela**, the world's biggest oil reserves holding country, possesses the eighth largest proven gas reserves, estimated at 197 Tcf as of the end of 2014. Associated gas accounts for nearly 90% of Venezuela's natural gas reserves. The country produced 2.8 Bcf/d of natural gas in 2014. A large share of the country's gas output is re-injected into oil fields to enhance crude oil extraction. Venezuela currently imports gas from Colombia in order to meet demand.
- **Nigeria** was estimated to contain 180 Tcf of proven natural gas reserves as of the end of 2014. Most of natural gas reserves of the country are located in the Niger Delta. Production in 2014 stood at 3.7 Bcf/d, down from 4.2 Bcf/d in 2012 largely as a result of security and gas transportation issues. Much of the country's natural gas production is flared since most of the oil fields lack the infrastructure to produce and market associated natural gas. Most of Nigeria's marketed natural gas is exported as LNG.

- **Algeria**'s proven natural gas reserves were estimated at 159 Tcf as of the end of 2014. Algeria's gas production has, however, declined in the recent years with the depletion of some of its mature gas fields. More than half of Algeria's proven natural gas reserves are contained in the country's largest gas field, Hassi R'Mel. Algeria produced 7.9 Bcf/d of gas in 2014.

Three other significant gas producers are Norway, Australia and Indonesia:

- **Norway** had proven reserves of 68 Tcf as of the end of 2014and produced 11.1 Bcf/d in 2014, of which around 93% was exported. The bulk of Norwegian gas is exported by pipeline to Europe, with a one train plant at Hammerfest (Snøhvit LNG) producing LNG.
- **Australia** had 132 Tcf of proven gas reserves as of the end of 2014and produced 5.3 Bcf/d in 2014, of which around 58% was exported. Gas exports from Australia are in the form of LNG exports from a number of projects in North-Western and Northern Australia. LNG exports from Queensland are expected to commence in 2015.
- **Indonesia** had 102 Tcf of proven gas reserves as of the end of 2014 and produced 7.1 Bcf/d of gas in 2014, of which around 42% was exported. Indonesia exports gas in the form of LNG from its Badak and Tangguh plants. There is also a pipeline to Singapore although gas supply through this is limited.

H.1.2.1 New Gas Resources

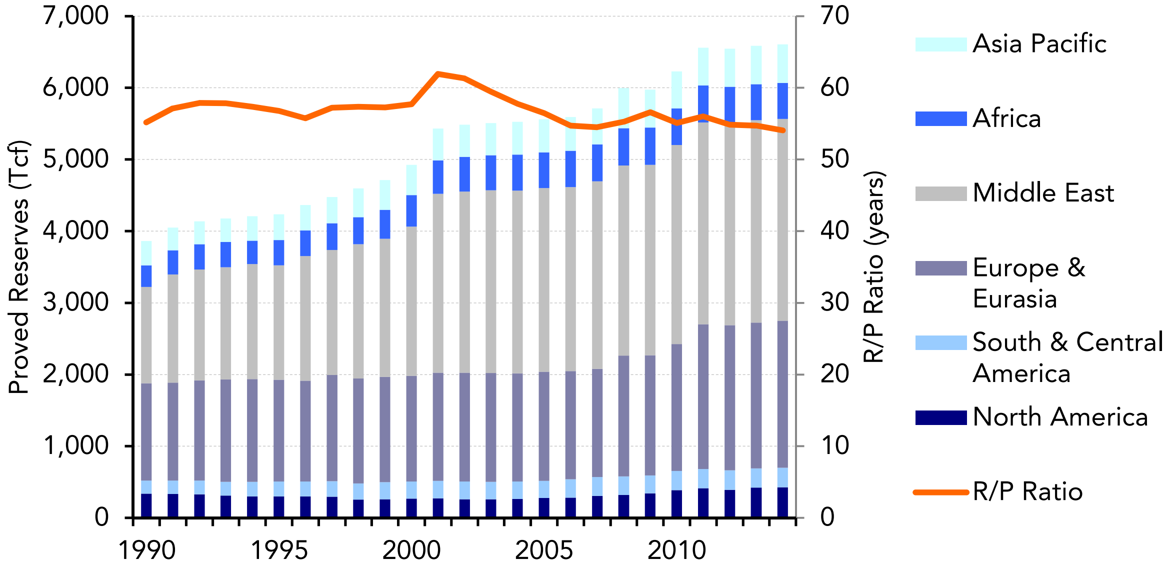
New reserves are being developed offshore of Mozambique and Tanzania. Mozambique's reserves are in the Rovuma Basin which runs along the north coast of Mozambique, and are estimated to be a minimum of 100 Tcf. However, the fields are in deep water with depths in excess of 2,100m in some areas. Tanzania's current reserves are thought to amount to around 20% of those in Mozambique, although this number is expected to rise significantly. The gas resources in Mozambique are at a more advanced stage of development than those in Tanzania. Both countries are likely to exploit the gas in the form of LNG as domestic markets are small.

H.1.2.2 Global Reserves Replacement

Technological improvements in exploration and drilling activities have enabled both new discoveries and the exploitation of previously identified reserves of natural gas, indeed the shale gas boom in North America is entirely due to technological developments in the E&P sector. As a result of these new discoveries and the heightened exploitation of existing reserves, there are many more producers of natural gas today than there were in the 1990s.

The global R/P ratio calculated using proven reserves has stayed between 50 – 60 years for the last two decades, as shown in the figure overleaf, indicating that globally the industry is finding new gas reserves in line with consumption. Taking into account probable and possible gas resources it is believed that the identified reserve base has a life in excess of 140 years at current production levels.

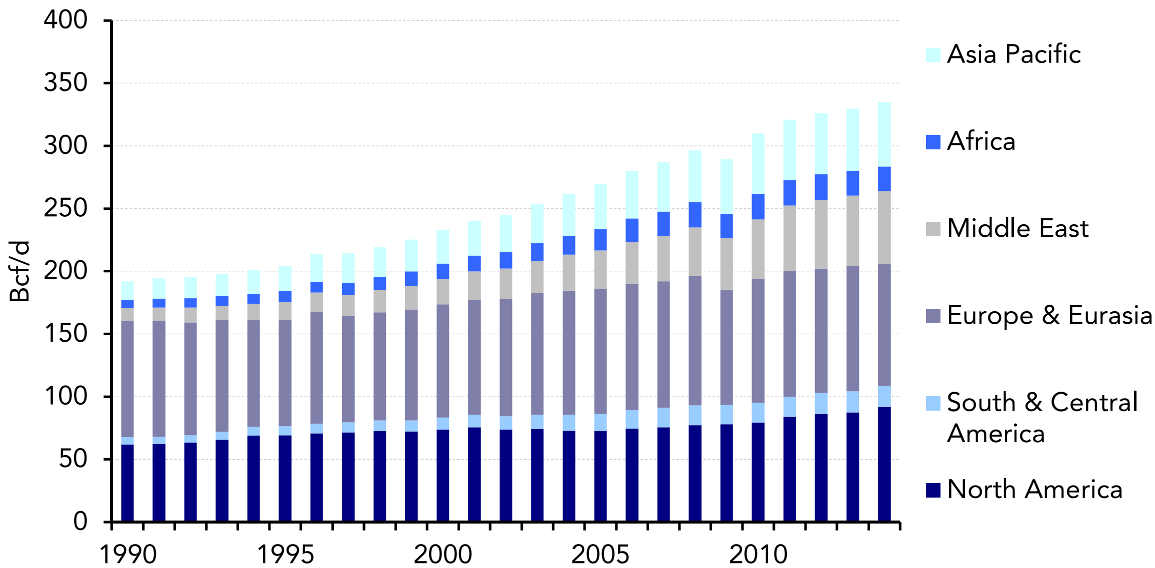
Figure H-3 Historical Global Gas Reserves & R/P Ratio
(source: BP Statistical Review of World Energy 2015)



H.1.3 Natural Gas Production

As shown in the figure below, global gas production rose to a new high of 335 Bcf/d in 2014, up from 233 Bcf/d in 2000. This represents average growth over this period of around 2.7% p.a. The largest contribution to this growth came from the Middle East, where production rose over the period from 20 Bcf/d to 58 Bcf/d, led by Qatar and Iran. Asia Pacific production was also a major factor in overall growth levels, increasing from 27 Bcf/d to 51 Bcf/d over the period, led by China.

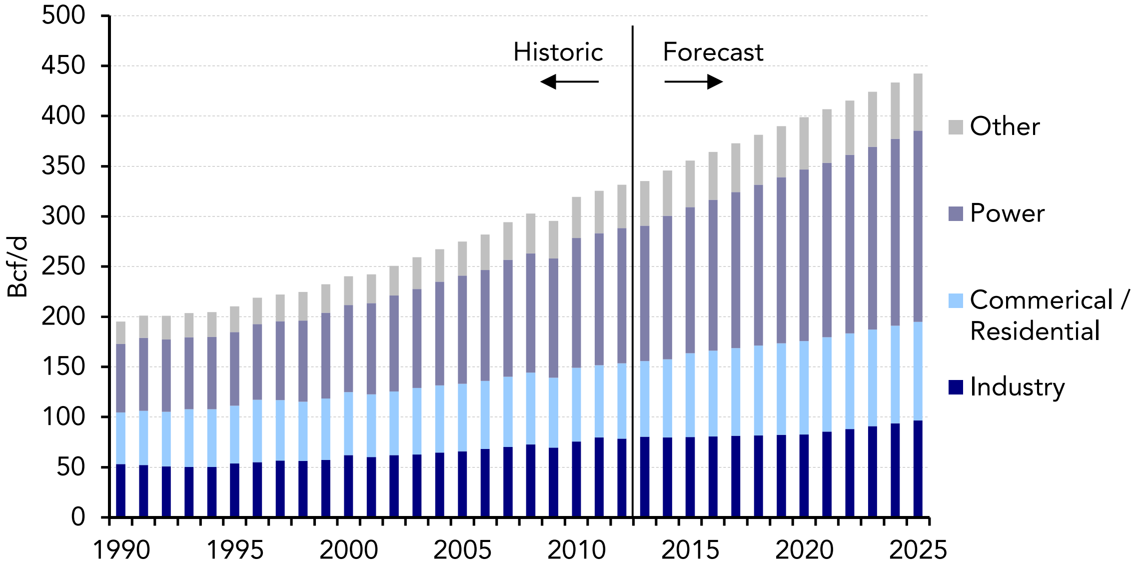
Figure H-4 Historical Global Gas Production
(source: BP Statistical Review of World Energy 2015)



H.1.4 Natural Gas Demand

This increase in global demand for natural gas has mainly been driven by the power sector as shown in the figure below. Demand for natural gas to generate electricity grew from ~68 Bcf/d in 1990 to an estimated 143 Bcf/d in 2014, representing ~41% of total natural gas demand. Over the same period, natural gas use in the industrial sector grew from a level of around 53 Bcf/d to an estimated 80 Bcf/d, with the combined commercial and residential sectors also increasing from 52 Bcf/d to an estimated 78 Bcf/d.

Figure H-5 Historical & Projected Global Gas Consumption by Sector
(source: IEA, Poten estimates)



On a global scale, over the next ten to fifteen years, natural gas is expected to increase significantly its share of the energy mix, overwhelming any regional-specific constraints, in large part due to the building of highly efficient CCGT plants. Such is the extent of the global power market that even small changes in the energy mix can have an enormous impact in the quantity of natural gas required. For example, the shuttering of nuclear power plants in Japan following the Fukushima Daiichi nuclear accident in March 2011 resulted in a huge surge in LNG demand, which tightened the global market. In France, which has long relied on nuclear power curtailing natural gas demand, gas-fired power generation is now projected to double by 2025, in a reversal of this tren, largely due to the Japanese accident. However, it is the growing economies, such as China, India, South Korea and South East Asia that are expected to have the largest impact on global natural gas demand (and LNG trade), principally for power generation. China's demand for natural gas is set to increase hugely and the effects of an apparently limited shift away from coal due to extreme pollution in its cities could be significant even before the absolute growth of gas demand is taken into account.

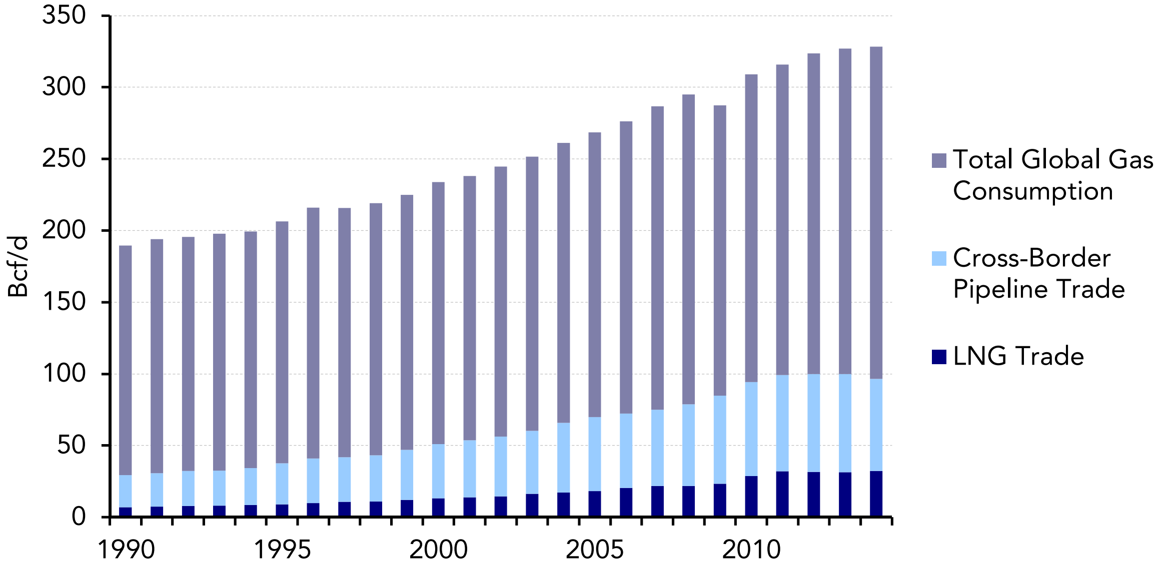
Going forwards, Poten's base projection is that global natural gas demand will reach a level of round 442 Bcf/d by 2025. The power sector remains the main demand driver for natural gas and is expected to account for nearly half of incremental demand from 2013 to 2025. This incremental growth is primarily attributable to switching from coal to natural gas for power generation as a result of natural gas' competitiveness and more stringent regulations on carbon emissions.

H.1.5 Natural Gas Trade

Natural gas markets are much less integrated than oil markets, given the cost and logistical difficulty of trading gas across borders. Most gas production is consumed within the producing country. Where gas is internationally traded this is mostly done by pipeline. Global gas trade has increased significantly over the last several decades and in 2014 it represented ~29% of total gas consumption, up from ~22% in 2000.

Figure H-6 Historical Global Gas Trade

(source: BP Statistical Review of World Energy)



The pattern of global trade in natural gas has evolved rapidly. Because natural gas has mainly been transported to consumers via pipeline, only one-third of natural gas consumed is traded internationally. Europe and North America are by far the largest markets integrated by pipelines, but their net imports have declined since 2005 on account of weaker economic activity, fuel competition in the power sector and higher gas production in the United States. One-third of internationally traded natural gas is shipped as LNG, and that share has been expanding rapidly, with the increase going mainly to Asia. There were almost 20 LNG producing countries in 2013. Qatar has rapidly developed LNG export capacity in the past decade and is now the largest exporter, accounting for about one-third of global LNG trade.

The shale gas boom in the US has triggered a sharp decline in prices as a result of a natural gas glut. This has had a significant impact on global gas trade patterns, as US LNG imports from Africa, the Middle East, and T&T have effectively ceased and pipeline imports from Canada have declined. In response, exporters have shifted LNG exports to other locations, such as China, Europe, and India, in response to the US reduction in imports. In the US redundant LNG import terminals are being converted to liquefaction plants to permit the export of LNG. The development of US LNG exports is already impacting global pricing.

H.1.6 Gas Market Evolution

There has been a general trend in gas markets towards the introduction of competition and deregulation in the sense that governments have retreated from active participation in gas markets and allowed the private sector to take over the commercial activities in the sector under a regulatory framework. This is most evident in the markets of North America and the UK, although others such as in Western Europe, Australia, New Zealand and Latin America have also made moves to create more competitive markets. Key to introducing competition is the unbundling of the gas commodity supply from transportation and related services and the removal of price controls. These changes revolutionise the way gas is traded, including the mechanisms used to price gas in contracts. As greater competition is introduced we have seen a number of market trends:

- Shorter-term and smaller contracts: There has been a pronounced shift towards shorter-term contracts, notably fixed-price spot deals of one-day to one-year duration, and a corresponding decline in the use of long-term contracts. The average size of individual contracts has diminished as buyers seek greater flexibility in balancing load on a daily and seasonal basis.
- Local distributors and marketers generally seek a balance between short- and mid-term supplies. Few companies now seek to contract for more than three years of supply. Power generators still contracts for long-term gas supply of five to ten years or more if they are able to sign back-to-back power purchase agreements so as to lock in a margin.
- Decline in take-or-pay commitments: The move to short-term spot trading has resulted in a decline in the use of take-or-pay commitments in medium- and long-term contracts. This has been most marked in North America, where pipeline companies encountered severe financial difficulties in the mid-1980s as a result of onerous commitments to lift gas at above market prices under long-term contracts with producers. While long-term contracts with power generators usually still include take-or-pay obligations, these typically have lower thresholds than in the past.
- Emergence of spot and futures markets: Spot markets - informal markets for over-the-counter trades of fixed volumes of gas at a negotiated market price - are a central feature of the competitive markets. Futures markets are also increasing in importance, both as risk management instruments and a means of buying and selling physical volumes. As much as a third of the North American market and close to a fifth of the British market is supplied with physical gas traded on the spot or futures market. Total trading volumes are considerably larger, as contracts are traded many times over. Spot trading has tended to become focussed on market hubs, facilitating the coordination of short-term gas purchasing and the booking of transportation and storage services.
- Spot- and futures-price indexation: The importance of spot and futures markets in gas pricing is greater than the size of those markets would suggest because of the widespread use of movements in spot/futures gas prices to index or escalate the base price in mid- and long-term contracts. In line with the oil market, almost all such contracts in the United States are indexed on spot or futures prices.

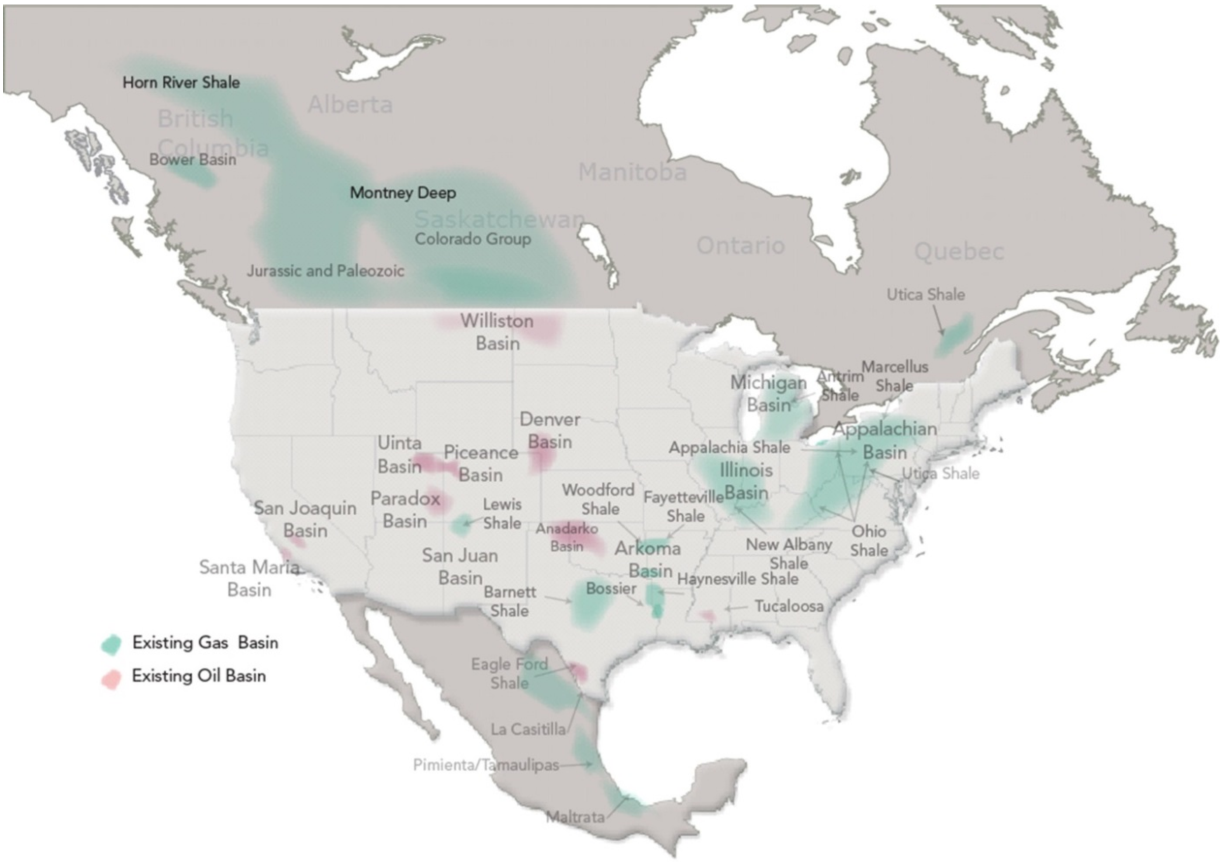
The structural aspects of gas market evolution are discussed in more detail in Appendix J of this report.

H.2 US SHALE GAS REVOLUTION

H.2.1 Overview

The existence of gas held in shale formations has been well understood in the US exploration and production industry. Producers operating in Texas, Louisiana and Pennsylvania all drilled through shale on their way to traditional gas reservoirs. Few E&P players viewed shale gas as having commercial potential. George Mitchell, founder of Mitchell Energy (now owned by Devon Energy) believed shale could be developed commercially and his company eventually found success in the Barnett shale basin near the Dallas-Fort Worth area by combining horizontal drilling with use of hydraulic fracturing during the 1990s.

Figure H-7 North American Shale Gas Basins



In 2006 gas production from shale basins accounted for less than 6% of gas produced in the US. Most of the shale gas production was from the Barnett Shale where Mitchell Energy was further improving on methods for extracting gas from shale. As production methods were proven in the Barnett Shale these skills were soon transferred to the Haynesville and Fayetteville shale basins and dramatic growth in shale gas production became apparent, as can be seen in the figure overleaf.

By 2013 gas production from shale basins accounted for just over 42% gas produced in the US. In addition to the Barnett, Haynesville and Fayetteville production was growing dramatically in other areas. Producers successfully applied the lessons learned and continually improved on production techniques. For example producers have reduced the time needed for each well drilled, increased the efficiency of drilling rig utilization, used longer horizontal laterals to improve individual well production and the fluid combinations used for hydraulic fracturing have increased well flow. Each of these improvements has contributed to lowering overall production costs. Such benefits have been clearly visible in the Marcellus shale basin as it has the fastest production growth and at competitive cost even with gas prices below US$4.00/MMBtu.

Figure H-8 Historical US Shale Gas Production

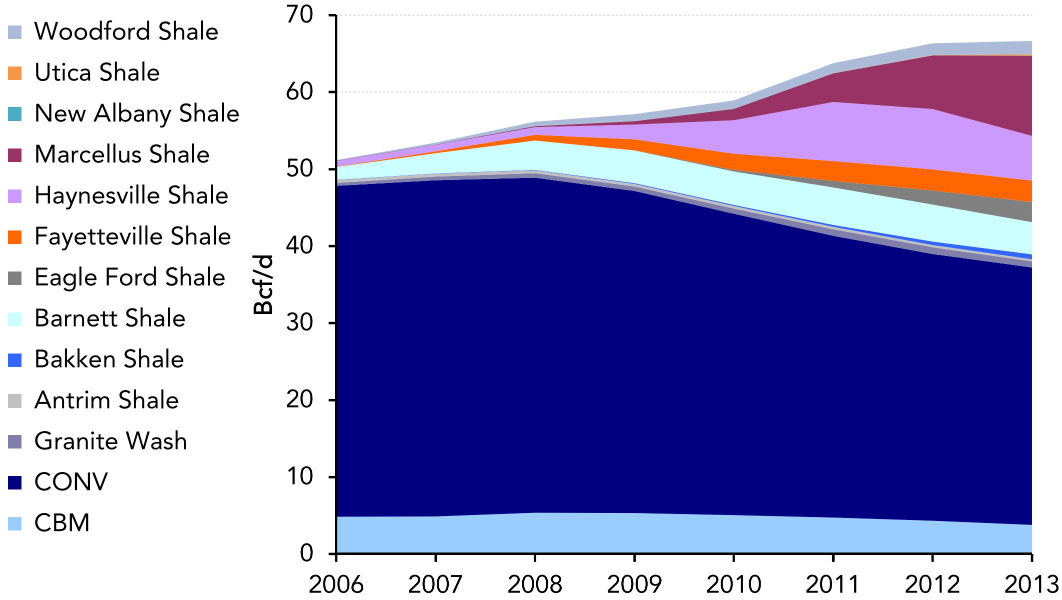


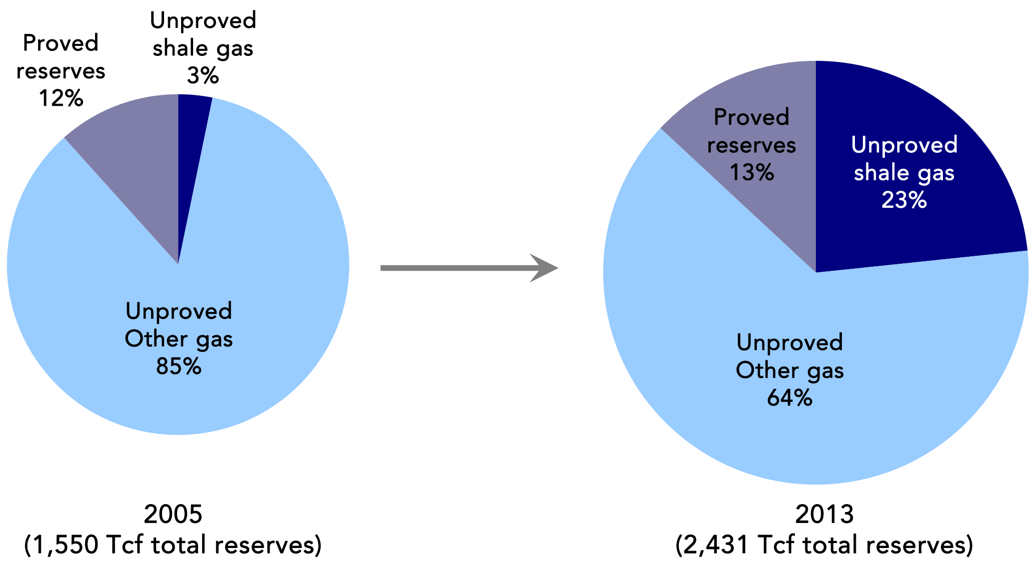
Figure H-9 Historical US Henry Hub Gas Prices

The impressive growth in shale gas production has impacted US gas prices as reflected in Henry Hub (HH) pricing. From highs above US$12/MMBtu in 2006 and 2008 HH prices dropped in early 2012 to US$2.00/MMBtu, levels not seen since 1999. Unsurprisingly 2012 was a high point for use of gas in electric generation as low gas prices stimulated a switch from coal. HH prices rebounded slightly over 2013, to a winter peak of US$6/MMBtu before dropping back below US$4/MMBtu by the end of 2014 and into early 2015.

H.2.2 Shale Gas Reserves and Production Outlook

US total natural gas reserves as measured by various agencies including the Potential Gas Committee and the US EIA, grew by 73% between 2005 and 2012. Total gas reserves include proven and unproven reserves. As shown in the pie charts in, total reserves grew from 1,550 Tcf in 2005 to 2,431 Tcf in 2013. Almost the entire increase is due to increased assessments of shale gas reserves.

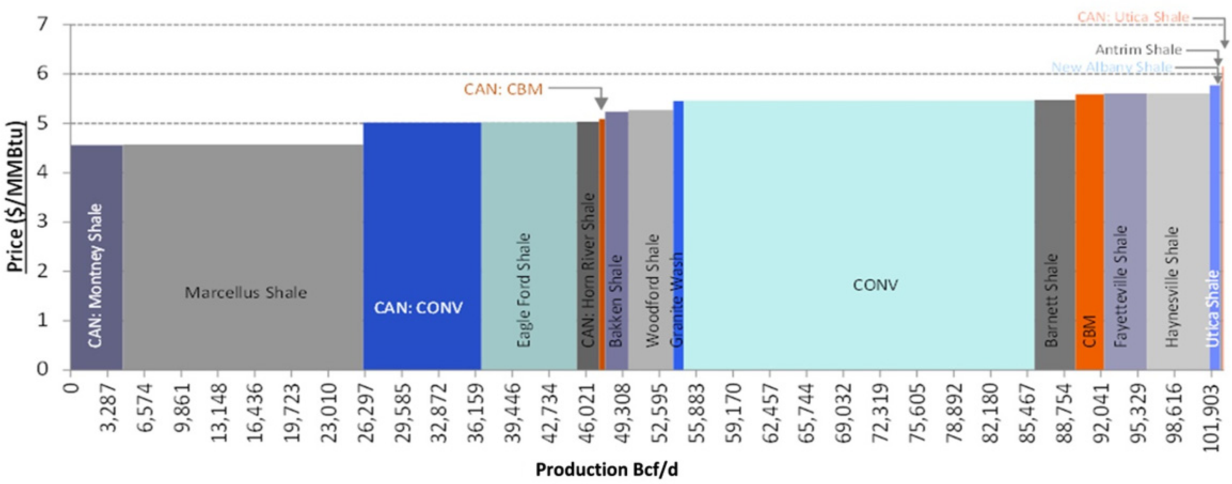
Figure H-10 Total US Natural Gas Reserves
(source: EIA)



On a percentage basis, Proved Reserves have decreased from 12% of total reserves to 11%. In reality however, Proved Reserves actually rose by 70% on a volumetric basis increasing from 179 Tcf to 304.7 Tcf. EIA announced proved shale gas reserves of 354 Tcf in December 2014 reflecting further development of the resource.

Low gas prices do remain a threat to the continued development of shale gas production. As already noted the success of shale gas production has resulted in low gas prices.

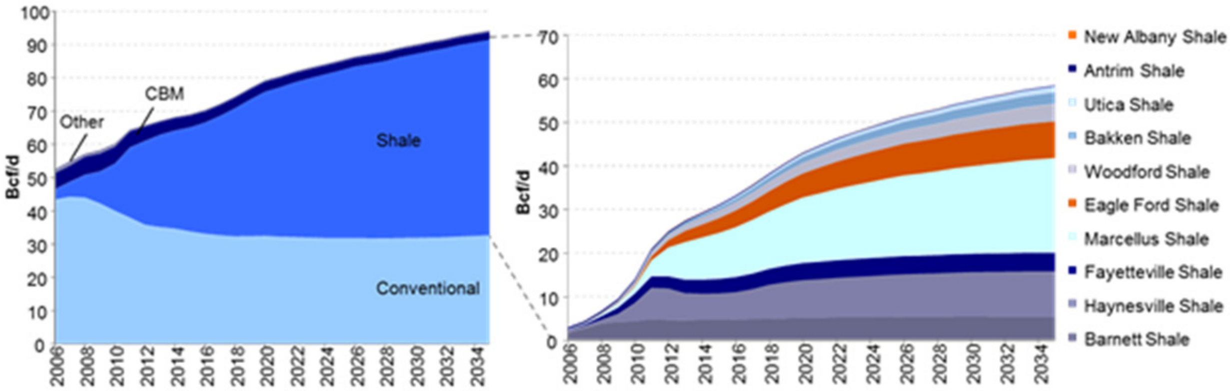
Figure H-11 Estimated North American Shale Gas Cost Curve



In the mature basins of Barnett, Haynesville and Fayetteville we expect that these drier shale areas will see production prices rising by 2025. Poten's forecast HH price increases as a result but the economics for some shale basins will prove challenging. Producer focus has turned to other shale areas where the resource includes gas and natural gas liquids. Production from such "wetter" shales can achieve revenues from liquid output offsetting a portion of production costs.

A focus on the wetter shale areas in the Eagle Ford and Marcellus basins is a positive story. Poten forecasts that in these areas production costs net of liquid credits should provide a good basis for continued development in these emerging areas. The Marcellus basin seems to offer very large potential as a current and future supply source. Beyond 2015, Poten expects production costs will continue to rise slowly. New well completion rules, environmental restrictions on hydraulic fracturing and increased water costs remain as potential threats for faster cost growth. These threats will be, in part, offset by continued improvement in drilling, well completion and production techniques.

Figure H-12 Projected US Shale Gas Production



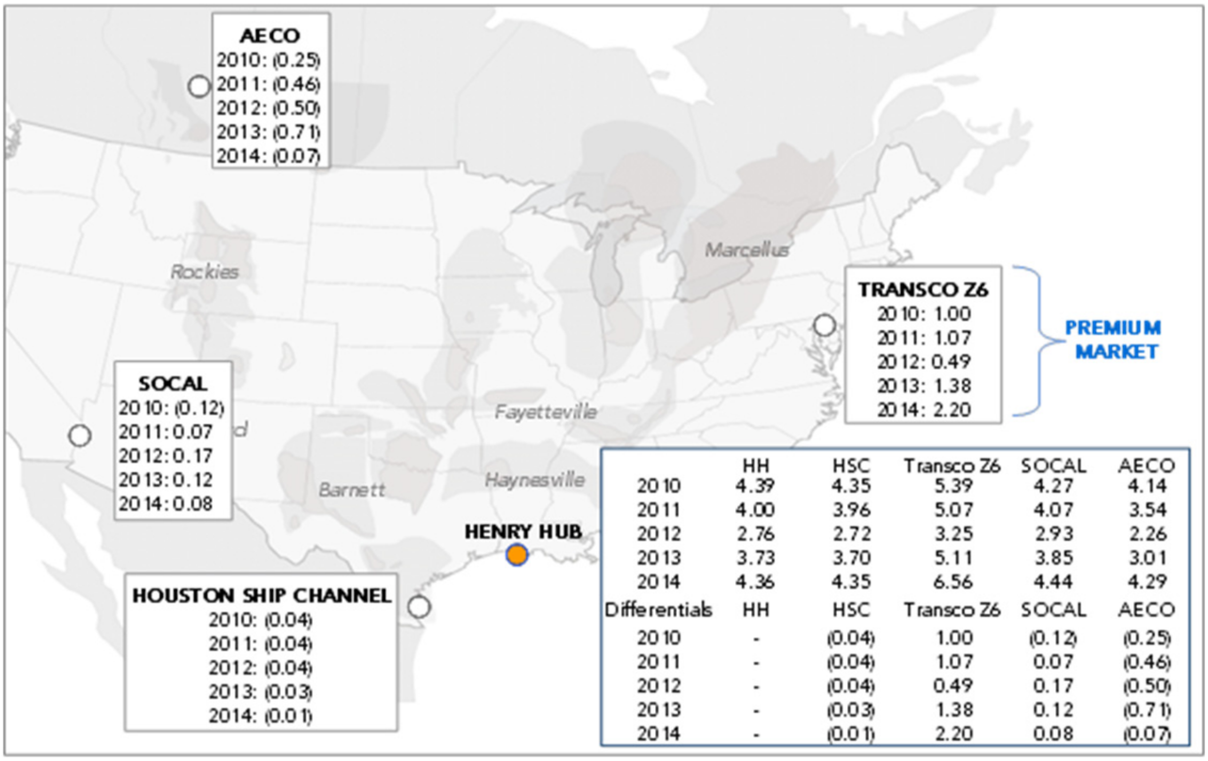
Poten's forecast through 2035 for total US gas production is shown in the graph to the left in the figure above. Shale gas production will continue to play an increasing part in the total available US gas supply and is forecast to grow at an average rate of around 4% per year through the forecast period. By 2035 shale gas production is projected to account for 64% of total US gas production. The graph on the right provides a more detailed picture of the expected contribution of shale gas production by basin. The Marcellus basin is forecast to continue its impressive growth accounting for more than one-third of the shale production by 2035.

H.2.3 Shale Gas Production and Regional Supply Hubs

At the time the HH futures contract started in 1990, three states (Texas, Louisiana and Oklahoma) accounted for 72% of all gas produced in the US. As of the end of 2013 Texas, Louisiana, Oklahoma and the Federal Deepwater Offshore areas only accounted for 47% of the gas produced in the US. Strong production growth occurred in three other states, Colorado, Arkansas and Pennsylvania reflecting drilling and production activity in the Niobrara, Haynesville and Marcellus shale basis, respectively.

Increased gas production typically results in at least two reactions in the local supply point. First, available supply increases potentially in excess of local demand driving local prices lower. Second, in order to bring local hub demand and supply back into balance a market participant, producer, pipeline, marketer or end user, will invest to increase pipeline capacity to create paths for additional supplies to be moved to more lucrative markets and relieve a local supply surplus.

Figure H-13 Pricing Hubs and 5 Year Basis Differentials to HH



	HH	HSC	Transco Z6	SOCAL	AECO
2010	4.39	4.35	5.39	4.27	4.14
2011	4.00	3.96	5.07	4.07	3.54
2012	2.76	2.72	3.25	2.93	2.26
2013	3.73	3.70	5.11	3.85	3.01
2014	4.36	4.35	6.56	4.44	4.29
Differentials	HH	HSC	Transco Z6	SOCAL	AECO
2010	-	(0.04)	1.00	(0.12)	(0.25)
2011	-	(0.04)	1.07	0.07	(0.46)
2012	-	(0.04)	0.49	0.17	(0.50)
2013	-	(0.03)	1.38	0.12	(0.71)
2014	-	(0.01)	2.20	0.08	(0.07)

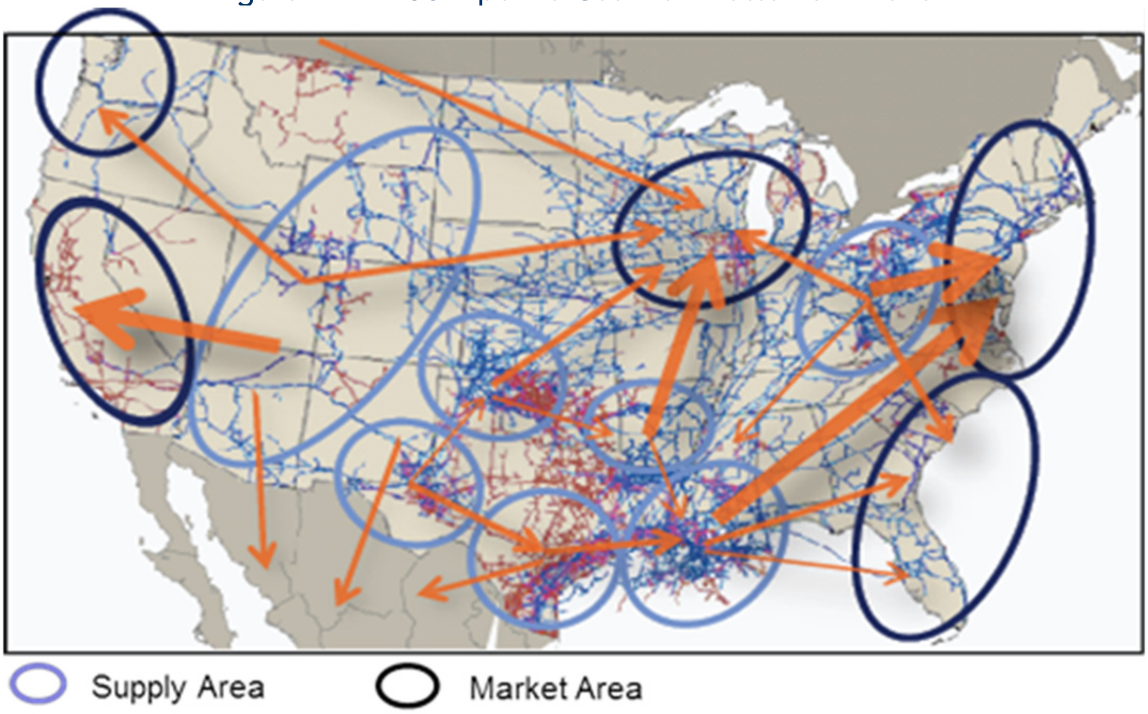
For example, in the map shown above four pricing hubs are reflected showing their yearly average price differential to HH for the five year period 2010 to 2014. In 2010 the Houston Ship Channel point experienced prices below HH, a negative basis of $0.04/MMBtu. In large part this negative basis was the result of increased production in the Barnett shale. Excess supply in the area depressed prices. During the course of the next three years pipeline capacity expansions and additions were made to allow production to flow on to other points reducing the local oversupply and allowing basis at the Houston Ship Channel to settle to an differential to HH of about US$0.01/MMBtu by 2014.

An interesting example is price developments at the Dominion South hub in the northeast including parts of Pennsylvania and West Virginia. This point is where new Marcellus gas production is being seen. The Dominion South hub has always experienced positive basis differentials to HH reflecting its premium position close to large gas markets along the East Coast from Washington, D.C., North to New York City. As Marcellus shale gas production has increased, the premium realised in the Appalachian basin has decreased reflecting the increased production available and, perhaps, the limitations in available pipeline capacity in the region. During the extreme weather event in the winter of 2013-2014 when prices along the Northeast US frequently exceeded $20/MMBtu, prices at Dominion South remained below $4/MMBtu.

H.2.4 Shale Gas Production Altering Pipeline Flow Patterns

Shale gas production is increasing in many areas of the US. In particular the rapid increase in production in the Marcellus area close to major end use markets is changing the reliance on the large, long-haul pipelines. Supply decisions are becoming increasingly regional and large gas utility companies serving markets in the major cities will likely be less dependent on gas supply transported through the large pipeline companies from the traditional producing states of Texas, Louisiana and Oklahoma. As LDCs begin to mix in supplies from sources nearer to end user sites, total pipeline transport costs will be reduced. In addition, LDCs may decide to end contracts for some pipeline capacity as such capacity may no longer be needed with supply available at nearby hubs.

Figure H-14 US Pipeline Gas Flow Patterns in 2013



The large pipeline companies have recognised a change in the gas supply flow and the need to alter their systems to meet the emerging market dynamics. Three large, long-haul pipelines have specifically discussed their need to address the changing flow dynamics. Transcontinental Gas Pipe Line (Transco) and Tennessee Gas Pipeline (Tennessee) are two large pipelines which begin in Texas and proceed north and east serving customers along the east coast of the US. Their customers include large utilities serving Atlanta, Washington, Baltimore, Philadelphia, New York and points in between.

The growth in shale gas production in the traditional supply areas such as the Barnett, Haynesville or Eagle Ford has not led to increased use of capacity going north primarily because rapid growth in the Marcellus has reduced the need to move gas to northern markets. A similar case involves the Rockies Express Pipeline which was built to bring gas production from the Rocky Mountain region to the large markets on the east coast. As with Transco and Tennessee, Rockies Express has discovered that their capacity is significantly underutilised as Marcellus gas supply backs out the market need for gas from the Rockies.

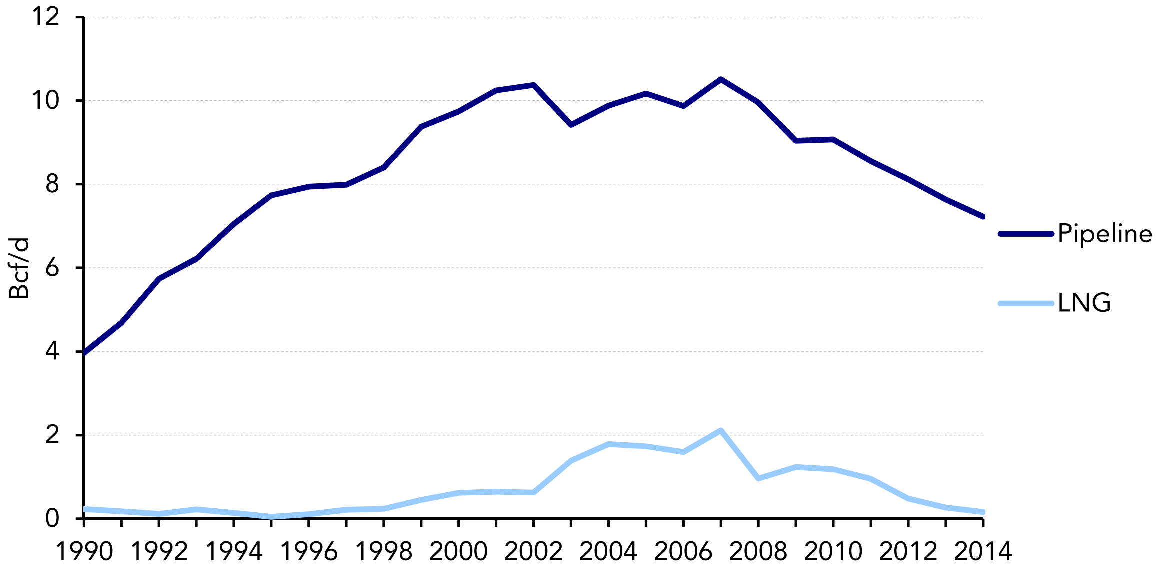
H.2.5 Fundamental Change to Supply/Demand Balance in US Gas Market

With the shale gas revolution the US natural gas market has changed fundamentally, from a demand-driven LNG importing market to a self-supplied market. The US market has experienced an increase in both demand and supply. According to the EIA, in 2013, US gas consumption totalled over 26 Tcf, with electric generation being the largest consumption sector, followed by the industrial, residential, commercial and other sectors. Continued growth of shale production has made gas cheaply available to compete against other sources of fuel.

As gas became cheaper, it started to displace coal in the power generation sector. Natural gas surpassed nuclear in 2006 to become the number two source of power generation fuel in the US after coal. Such expansion was possible due to aggressive CCGT construction that began in the late 1990s, when CCGT emerged as technology of choice for power generation. Coal has lost market share to gas since 2008 with historically high natural gas production and HH prices at relatively low levels. Competitiveness of coal vs. gas varies regionally, depending on delivered prices to each location.

The need for imported gas has dropped away and net imports of natural gas into the US fell 7% in 2014, continuing a decline that began in 2007. (The drop in imports from 2007 to 2014 was 42%). Abundant production of natural gas helped reduce US reliance on imported natural gas and helped maintain a high price differential between domestic and foreign markets outside of North America, increasing interest in the potential export of US LNG and the development of gas-based petrochemicals.

Figure H-15 Historical US Natural Gas Imports
(source: EIA)



The combination of increased gas production, low HH prices and an elimination of the need for LNG imports created the momentum to convert existing LNG facilities to add liquefaction capacity. Future US LNG exports are discussed subsequently.

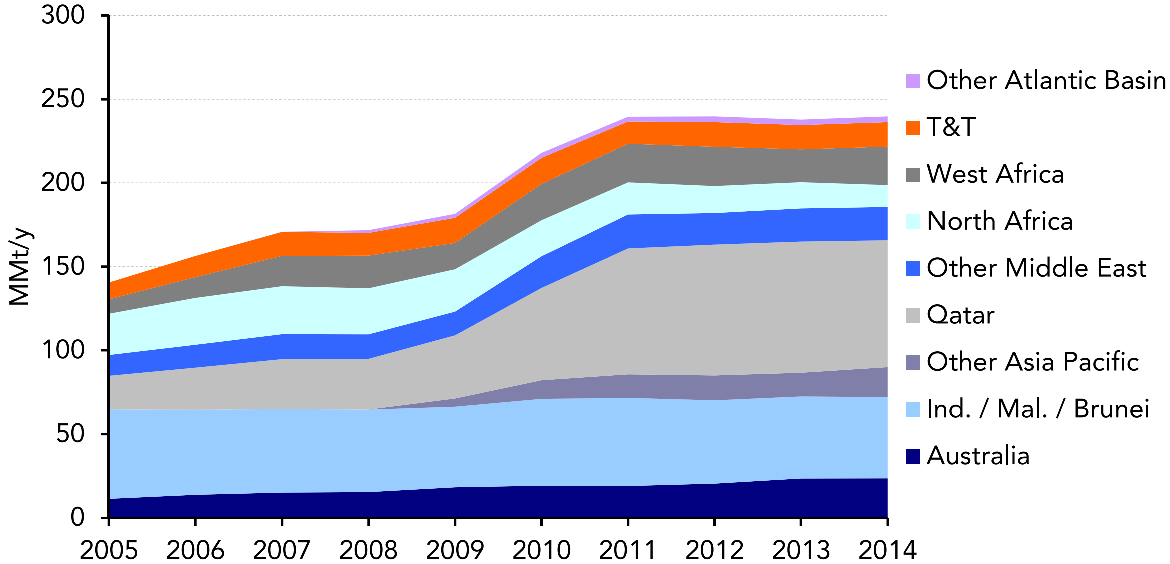
It is not just LNG trade that has been impacted by the advent of shale gas. There have been a number of new developments in ammonia and methanol seeking to take advantage of the abundance of low-priced gas. In the most extreme example Methanex have relocated two 1 MMt/y plants from Chile, where gas supplies dedicated to the original project had proven to be less than expected, to Geismar on the US Gulf Coast. The first plant has already entered production. The development of ammonia and methanol plants in the US is discussed in more detail subsequently.

H.3 LNG MARKETS

H.3.1 LNG Supply

From 2000 through 2014, the number of countries producing LNG increased from 12 to 19. LNG exports more than doubled over this period from 113.6 MMt in 2000 to 243.8 MMt in 2014, as shown in the figure below, driven in part by export growth in Qatar. In 2000, Qatar exported approximately 12 MMt, or approximately 10% of global exports; by 2014, Qatar exported 77.2 MMt, or nearly one-third of global exports with production spurred by the building of six 7.8 MMy/y "mega-trains", the biggest ever built.

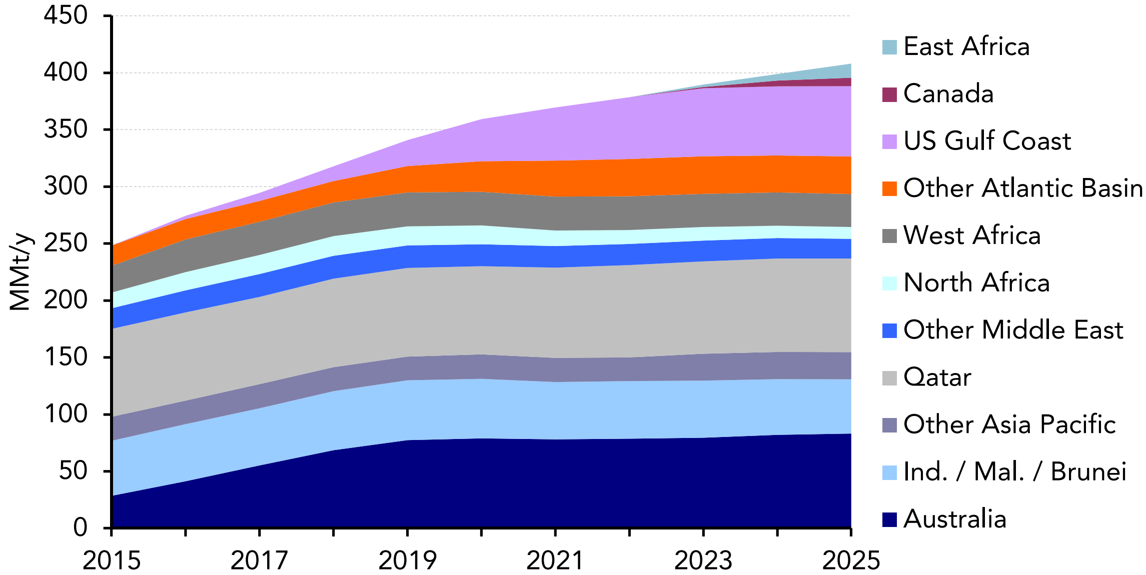
Figure H-16 Historical LNG Supply



Liquefaction plants located in the Atlantic Basin made up around 23% of global LNG production in 2014 (around 6% of which came from T&T) with Middle Eastern production accounting for 40% and Asia-Pacific the remaining 37%.

Based on projects currently being undertaken Poten forecasts LNG production will reach ~400 MMt/y by 2025, as shown in the figure overleaf.

Figure H-17 Projected LNG Supply



Australia is leading lead the next major LNG export expansion, while new capacity is also under construction in Papua New Guinea, Malaysia, Indonesia and Russia. Australia is projected to produce 75 MMt/y of LNG at 10 projects by 2020. However, high construction costs are such that no additional project sanctions beyond those already committed are expected for the foreseeable future.

North America and East Africa are expected to be key future LNG suppliers. By 2025, Poten projects North American (US and Canada) and East African (Mozambique and Tanzania) LNG exports to reach 69 MMt/y and 12 MMt/y respectively.

The US was once considered a major import destination and many LNG export projects, including ALNG, were built predominantly to supply this huge gas market. However, the surge in unconventional natural gas production has converted the nation into a potentially large LNG exporter rivalling Qatar and Australia, with over 200 MMt/y of potential supply at various stages of planning. Various projects are planned to add liquefaction trains at import terminals that are no longer needed, while numerous greenfield projects are also planned. LNG from the first of the US liquefaction projects under development (Sabine Pass) is expected by late 2015 or early 2016. Canada also has >100 MMt/y of export plans and has a shipping cost advantage to premium Asian markets vs. the US, but is likely to be a very costly environment for project development.

Operators offshore Mozambique and Tanzania are reported to have discovered at least around 120 Tcf of gas reserves and plan to develop multiple LNG export trains. However, establishing the commercial and regulatory structures to support LNG exports will take time.

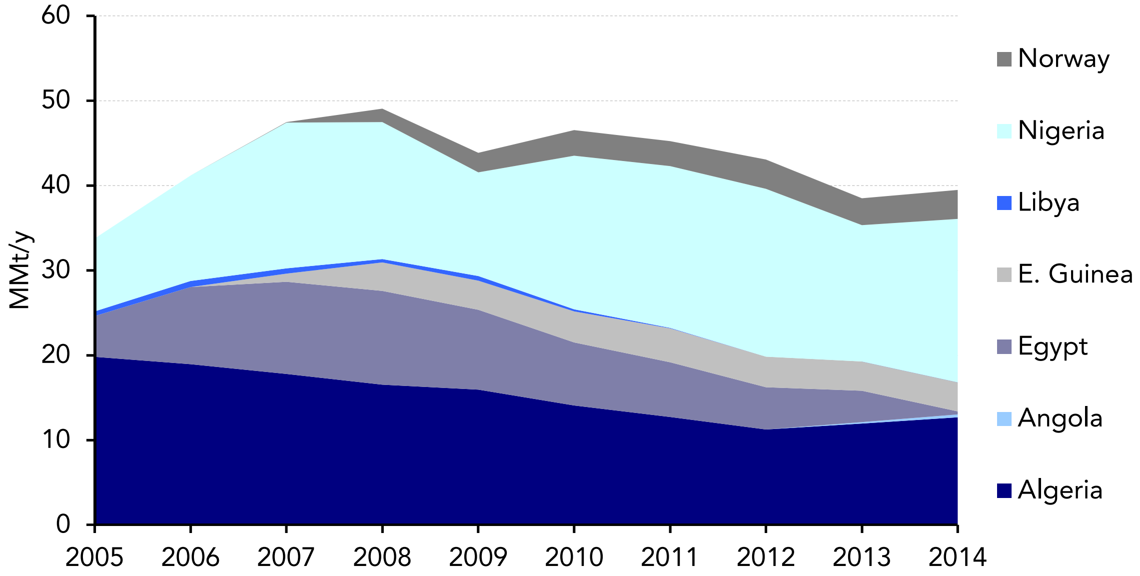
Surging Japanese LNG demand following the Fukushima Daiichi nuclear explosion in March 2011 created a tight LNG market. Combined with US$100/bbl-plus oil prices, this contributed to a flood of LNG projects sanctions as buyers pursued term LNG supplies. Many of these FIDs were supported by term purchase contracts at high oil-linked prices. As of early 2015, oil prices have collapsed by half, likely slowing the pace of FIDs.

We are now seeing a move towards more of a buyers' market for supply towards the end of the decade as new projects compete for markets. This is being illustrated by declining prices in the market for long-term contracts. Both North America and East Africa will play an important role in setting future long-term LNG pricing as they compete for markets.

H.3.1.1 Supply – Europe and Africa

Current regional capacity is ~82 MMt/y, although estimated 2014 production was only around 39 MMt, as shown in the figure below. This was primarily as a result of feedgas availability issues in Algeria, Angola, Egypt and Nigeria. Nigeria (19.3 MMt) and Algeria (12.7 MMt) are the largest producers in the region and accounted for ~81% of regional supply in 2014.

Figure H-18 Historical LNG Supply: Europe & Africa



The table overleaf shows liquefaction projects within Africa and Europe (Russia and Norway) that are either existing, under construction or planned. The only project currently under construction is Russia's Yamal LNG, which is targeting 2017 start-up but is likely to be delayed; FID was taken in late 2013, but development has been impacted by the sanctions on Russia.

Table H-2 Liquefaction Capacity: Europe & Africa: Existing & Planned

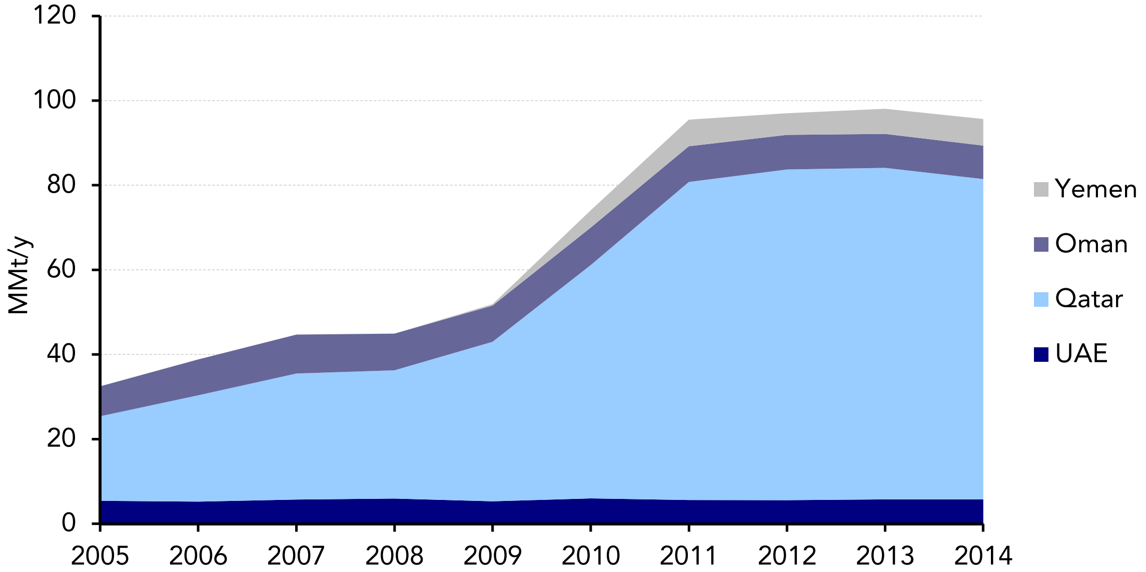
Project	Country	Number of Trains	Total Capacity (MMt/y)	Startup	Sponsors
EXISTING					
Arzew GL4Z (Camel)	Algeria	3	1.5	1964	Sonatrach (100%)
Bethioua GL1Z	Algeria	6	10.5	1978	Sonatrach (100%)
Bethioua GL2Z	Algeria	6	10.5	1981	Sonatrach (100%)
Gassi Touil GL3Z	Algeria	1	4.5	2014	Sonatrach (100%)
Skikda GL1K T10	Algeria	1	0.9	1972	Sonatrach (100%)
Skikda GL2K T5P, 6P	Algeria	2	2.5	1981	Sonatrach (100%)
Skikda replacement	Algeria	1	4.5	2013	Sonatrach (100%)
Angola LNG	Angola	1	5.2	2012	BP (13.6%), Chevron (36%), ENI Gas & Power (13.6%), Sonangol (22.8%), Total (13.6%)
Egyptian LNG T1	Egypt	1	3.6	2005	BG (35.5%), EGAS (12%), EGPC (12%), GdF (5%), Petronas (35.5%)
Egyptian LNG T2	Egypt	1	3.6	2005	BG (38%), Petronas (38%), EGAS (12%), EGPC (12%)
SEGAS LNG T1	Egypt	1	5.0	2005	EGPC (10%), EGAS (10%), Union Fenosa Gas (80%)
Equatorial Guinea LNG	Eq. Guinea	1	3.7	2007	Marathon (60%), Marubeni (6.5%), Mitsui & Co (8.5%), Sonagas (25%)
NLNG 1,2	Nigeria	2	6.6	1999	NNPC (49%), Shell (25.6%), Total (15%), AGIP (10.4%)
NLNG 3	Nigeria	1	3.3	2002	As above
NLNG-Plus (T 4,5)	Nigeria	2	8.0	2005	As above
NLNG 6	Nigeria	1	4.0	2008	As above
Snohvit LNG	Norway	1	4.1	2007	Hess (3.3%), GDF SUEZ (12%), Petoro (30%), RWE (2.8%), StatoilHydro (33.5%), Total (18.4%)
UNDER CONSTRUCTION					
Yamal LNG	Russia	3	16.5	2017	NOVATEK (60%), Total (20%), CNPC (20%)
PLANNED					
Mozambique LNG	Mozambique	2	10.0	2019	Anadarko (26.5%), Mitsui (20%), OVL/OIL (20%), BPCL (10%),PTT (8.5%), ENH (15%)
Block 4 (onshore)	Mozambique	2	10.0	2020	Eni (50%), CNPC (20%), Galp (10%), Kogas (10%), ENH (10%)
Block 4 FLNG	Mozambique	1	2.5	2019	As above
Brass LNG	Nigeria	2	10.0	TBD	NNPC, Eni, Total
NLNG 7	Nigeria	1	8.5	TBD	AGIP (10.4%), NNPC (49%), Shell (25.6%), Total (15%)
Tanzania LNG	Tanzania	TBD	TBD	TBD	TBD

In addition to potential East African exports discussed previously, various new export projects have been discussed for Nigeria over recent years. However, these have made limited progress due to regulatory uncertainty and this situation does not appear likely to change in the near future.

H.3.1.2 Supply – Middle East

Despite containing close to 40% of global natural gas reserves, Middle Eastern LNG production is not expected to increase substantially from current levels of ~100 MMt/y. Large reserves sustained unprecedented growth in LNG exports over the past decade, mainly from Qatar, as shown in the figure overleaf.

Figure H-19 Historical LNG Supply: Middle East



However, no new FID has been taken in the region since Qatargas 4 in 2007, and there are no new projects planned. Qatar could add 10-12 MMt/y of extra capacity by de-bottlenecking the 7.8 MMt/y mega trains, but QP imposed a moratorium in 2005 on further projects utilising the North Field in order to study the behaviour of the field following the huge increase in production. This moratorium remains in place.

Existing regional projects are shown in the table below.

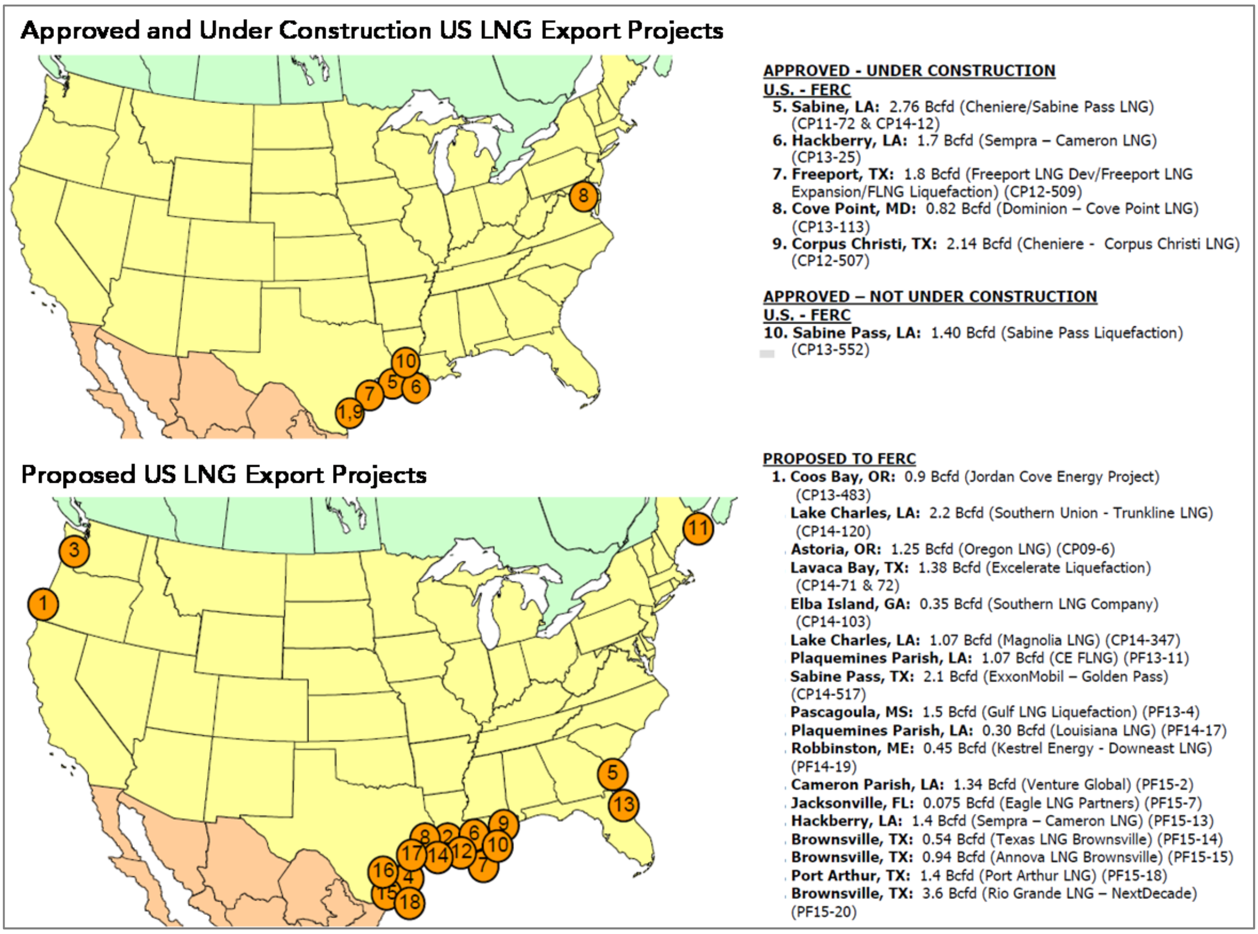
Table H-3 Liquefaction Capacity: Middle East: Existing

Project	Country	Number of Trains	Total Capacity (MMt/y)	Startup
EXISTING				
ADGAS 1	UAE	2	2.5	1977
ADGAS 2	UAE	1	3.3	1994
Qatargas 1	Qatar	3	9.9	1996
Qatargas 2 T4	Qatar	1	7.8	2009
Qatargas 2 T5	Qatar	1	7.8	2009
Qatargas 3 T6	Qatar	1	7.8	2010
Qatargas 4 T7	Qatar	1	7.8	2011
RasGas 1	Qatar	2	6.6	1999
RasGas 2 T3	Qatar	1	4.7	2004
RasGas 2 T4	Qatar	1	4.7	2005
RasGas 2 T5	Qatar	1	4.7	2007
RasGas 3 T6	Qatar	1	7.8	2009
RasGas 3 T7	Qatar	1	7.8	2010
Oman LNG	Oman	2	6.6	2000
Qalhat LNG	Oman	1	3.3	2006
Yemen LNG	Yemen	2	6.7	2009

H.3.1.3 Supply – US

As discussed previously, the abundance of gas in the US market as a result of shale gas development is such that there are now a large number of planned projects to export LNG from the US to overseas markets. There is currently over 290 MMt/y of announced US liquefaction capacity, including projects to converted redundant import terminals and greenfield projects, as shown in the figure below.

Figure H-20 FERC Approved & Proposed US LNG Export Projects
(source: FERC)



Total planned US capacity is equivalent to ~120% of total 2014 global LNG trade. As such it is clear that much of this capacity will not be developed as market growth will be insufficient to absorb even close to these volumes. Success or failure of different projects will depend on a variety of factors, including:

- Receipt of regulatory approvals
- Commercial arrangements of sufficient amount to justify construction of liquefaction facilities
- Financial strength of either LNG buyers or liquefaction tolling customers

Although many of these projects will not come to fruition, the market competition introduced by US exports is already having a substantial impact on long-term LNG pricing, as is discussed subsequently, and in Poten's view this impact will continue to grow as potential US suppliers compete for market share with existing and planned liquefaction projects across the globe.

US Federal Energy Regulatory Commission (FERC) review of a project's Final Environmental Impact Statement (FEIS), or its equivalent Environmental Assessment (EA), is the bottleneck on project development. It is only once FERC approval has been granted that the US Department of Energy (DOE) will consider issuing approval to export to countries that do not have a Free Trade Agreement (FTA) with the US. This category includes all of the world's major LNG importing countries with the exception of South Korea. The status of projects in the FERC process and potential start-up dates are shown in the table below.

Table H-4 Progress of Liquefaction Projects Filed with FERC

FERC Filing stage
Estimated processing time: 12 -15 months

	CAPACITY		SPONSOR	FERC FILING STAGE				FINAL AUTHORIZATIONS / POTENTIAL FIRST CARGO	
Project[1]	Number of Trains	Total Capacity (MMt/y)		Filing of application	Issuance of Schedule	Issuance of FEIS/EA	Federal Authorisation Decision	Final Authorisations / Potential FID	Potential 1st Cargo (FID + 42 months)
Sabine Pass, LA	4	18.0	Cheniere				Apr-12	Aug-12	Feb-16
Cameron, LA	3	13.5	Sempra (50.2%), Mitsui (16.6%), Mitsubishi (16.6%), GDF Suez (16.6%)			Apr-14	Jun-14	Aug-14	Feb-18
Freeport, TX	3	13.2	Michael Smith (57.5%), GIP (25%), Osaka Gas (10%), Dow (7.5%)			May-14	Jul-14	Nov-14	May-18
Cove Point, MD	1	5.3	Dominion		May-13	Jun-14	Sep-14	Oct-14	Apr-18
Cheniere Corpus Christi, TX	3	13.5	Cheniere		Feb-14	Oct-14	Dec-14	May-15	Nov-18
Sabine Pass Expansion, TX	2	9.0	Cheniere		May-14	Dec-14	Apr-15	Jun-15	Dec-18
Jordan Cove, OR	4	6.0	Veresen	May-13	Jul-14	*Jun-15*	*Sep-15*	Dec-15	Dec-19[3]
Magnolia LNG, LA	4	8.0	LNG Ltd.	Apr-14	Apr-15	*Nov-15*	*Feb-16*	May-16	Nov-19
Oregon LNG, OR	2	9.0	Leucadia National Corporation	Jun-13	Apr-15	*Feb-16*	*May-16*	Aug-16	Feb-20
Trunkline LNG, LA[2]	3	16.2	Energy Transfer	Mar-14	Jan-15	*Aug-15*	*Nov-16*	Feb-17	Aug-20

1 Projects ranked by progress in FERC process
2 Lake Charles LNG is under Trunkline LLC.
3 Assume 48 months to first LNG as per sponsor schedule

Italic - FERC scheduled

FERC Schedule | FERC Filing Stage | FERC Full Approval | Actual | Assumed | Potential

The first 5 of the projects listed are currently under construction (only the first 2 trains at Corpus Christi), totalling around 57 MMt/y of capacity, dwarfing the existing 14.6 MMt/y production capacity at T&T's ALNG.

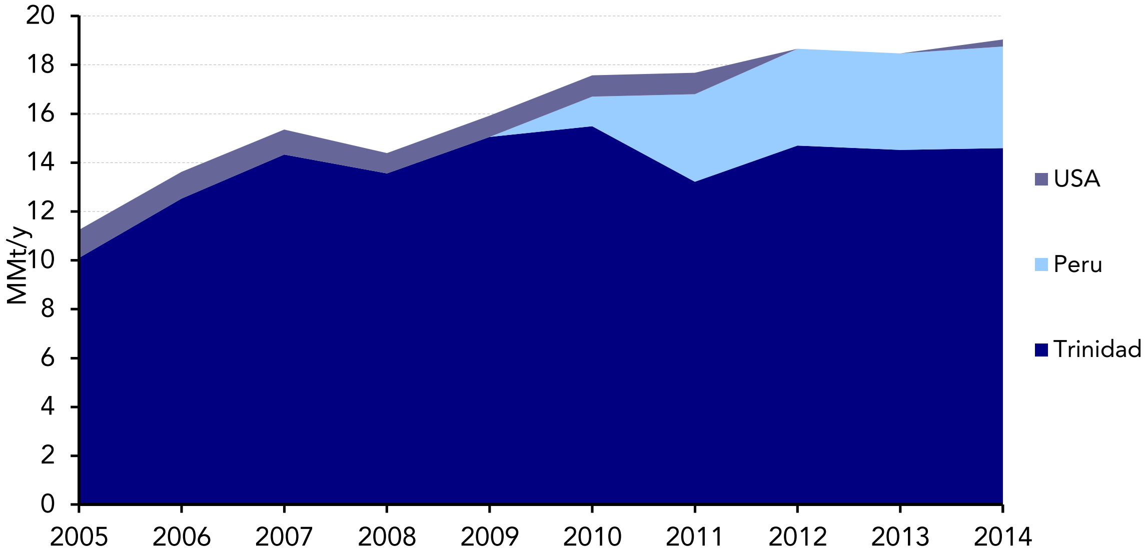
H.3.1.4 Supply – Other Americas

T&T and Peru are currently the only LNG exporters in the Americas (other than Alaska's Kenai LNG plant which has recently restarted exporting a few cargos per year). The four trains at ALNG have a combined capacity of around 15 MMt/y and started up between 1999 and 2005, while the 4.5 MMt/y Peru LNG plant started up in 2010. As a result of these developments, regional LNG exports peaked at over 18 MMt/y in 2012, as shown in the figure overleaf. Details of the individual liquefaction trains are included in the table below.

Table H-5 Liquefaction Capacity: Other Americas: Existing

Project	Country	Number of Trains	Total Capacity (MMt/y)	Startup
EXISTING				
Peru LNG	Peru	1	4.5	2010
Atlantic LNG T1	Trinidad	1	3.3	1999
Atlantic LNG T2	Trinidad	1	3.3	2002
Atlantic LNG T3	Trinidad	1	3.3	2003
Atlantic LNG T4	Trinidad	1	5.2	2005

Figure H-21 Historical LNG Supply: Americas



Other than the US, major new liquefaction capacity in the region is also planned from Western Canada. Over 130 MMt/y of planned export capacity has been approved by the National Energy Board (NEB) thus far, as shown in the table below.

Table H-6 Planned Western Canada LNG Export Projects

Project	Sponsors	Volume (MMt/y)	NEB filing	CEAA filing	BCEAO filing
Kitimat LNG	Chevron	10	√	EA In Progress	Certified
Douglas Channel	LNG Partners, Golar LNG	1.9	√	n/a	n/a
LNG Canada	Shell, PetroChina, Kogas, Mitsubishi	24	√	Substitution	PA
Pacific NorthWest LNG	Petronas, Japex, IOC, PetroBrunei, Sinopec	18	√	EA In Progress	UR
Prince Rupert LNG	BG Group	21.6	√	EA In Progress	PA
WCC LNG	ExxonMobil, Imperial Oil	30	√	n/a	n/a
Woodfibre LNG	Pacific Oil & Gas	2.1	√	Substitution	PA
Triton LNG	Altagas, Idemitsu	2.3	√	n/a	n/a
Aurora LNG	CNOOC, INPEX, JGC	24	√	Under Consideration	PA
Kitsault Energy	Kitsault Energy	20	UR	n/a	n/a
Canada Stewart Energy	Canada Stewart Energy	30	UR	n/a	n/a
WesPac Midstream	WesPac Midstream	3	UR	n/a	n/a
Steelhead LNG	Steelhead LNG	30	UR	n/a	n/a
Grassy Point LNG	Woodside Energy	20	UR	Under Consideration	PA
Discovery LNG	Quicksilver Resources	20	UR	n/a	n/a
Cedar LNG	Cedar LNG Export Development	15	UR	n/a	n/a
Orca LNG	Orca LNG Ltd.	24	UR	n/a	n/a
	TOTAL	295.9			

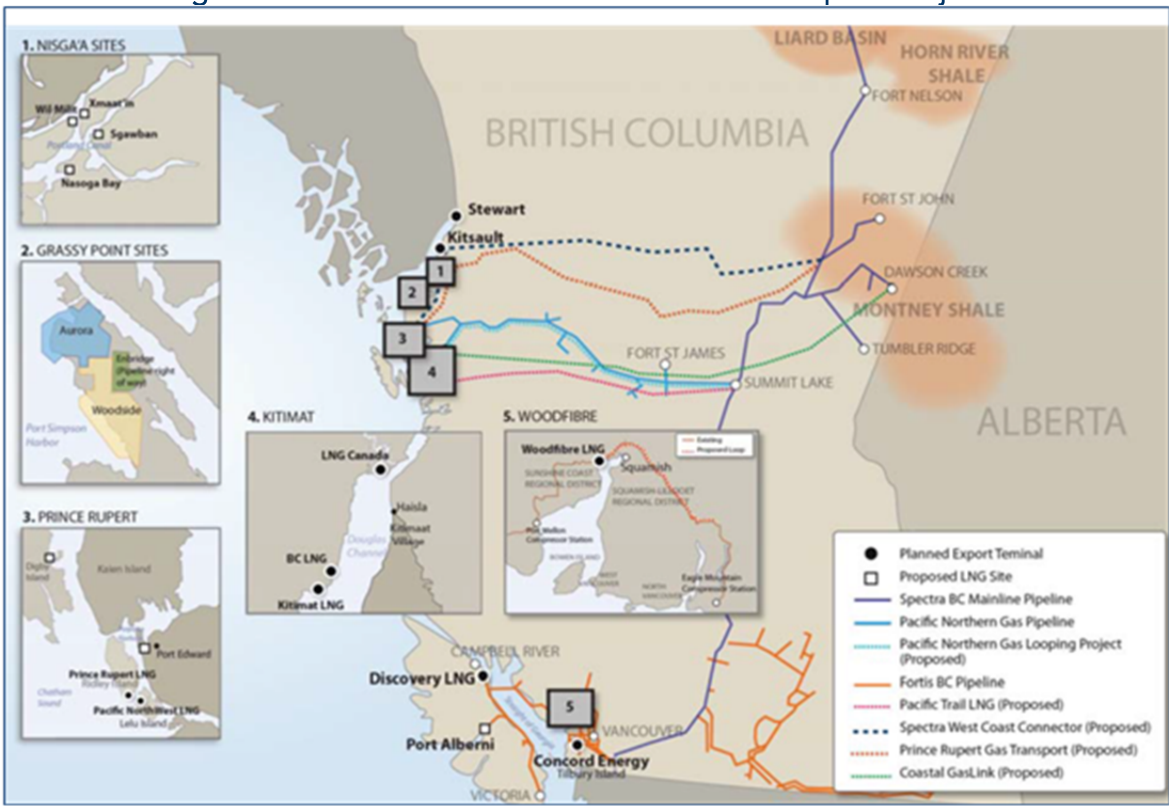
NEB - National Energy Board
CEAA - Canadian Environmental Assessment Agency
BCEAO - British Columbia Environmental Assessment Office

UR - Under Review
PA - Pre-Application

Strong reserves availability as a result of North American shale gas developments and short shipping distances to Asia are the drivers of these projects. However, none of the projects have yet taken FID. These projects are likely to be very high cost and carry a high risk of construction cost increases. Most of them need to build high cost pipelines to bring feed gas to shore, as shown in the figure below. Canadian labour laws and conditions have many similarities with Australia, where huge cost increases became the norm. In addition, indigenous population issues are likely to be problematic, particularly along pipeline routes. Environmental/permitting risks are also perceived to be high.

As a result of the development challenges, Poten predicts that LNG exports from Canada will ramp up only slowly, reaching around 7 MMt/y by 2025.

Figure H-22 Planned Western Canada LNG Export Projects



H.3.1.5 Asia Pacific

LNG exports from the Asia Pacific region have grown modestly from around 63 MMt in 2005 to around 86 MMt in 2014, as shown in the figure overleaf. Increased supply from Malaysia, Australia and from the Tangguh (Indonesia) and Sakhalin (Russia) projects have offset declines elsewhere. For example, production at existing Indonesian projects (Arun and Bontang) tapered off significantly over recent years. Details of the existing projects are shown in the table overleaf.

Figure H-23 Historical LNG Supply: Asia Pacific

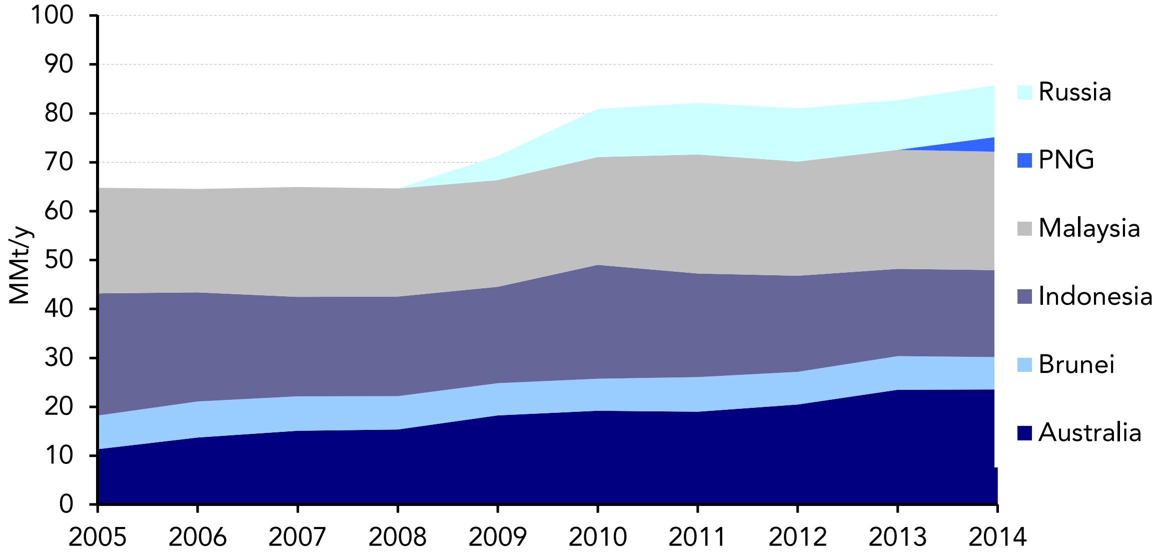


Table H-7 Liquefaction Capacity: Asia Pacific: Existing

Project	Country	Number of Trains	Total Capacity (MMt/y)	Startup	Sponsors
EXISTING					
North West Shelf	Australia	2	5.0	1989	Woodside, BP, BHP Billiton, MIMI, Chevron, Shell 16.67% each
North West Shelf T3	Australia	1	2.5	1993	As above
North West Shelf T4	Australia	1	4.2	2004	As above
North West Shelf T5	Australia	1	4.4	2008	As above
Darwin LNG	Australia	1	3.5	2006	ConocoPhillips (57.15%), Eni (10.99%), Inpex (11.27%), Santos (11.39%), Tepco/Tokyo Gas (9.20%)
Pluto LNG	Australia	1	4.3	2012	Kansai Electric (5%), Tokyo Gas (5%), Woodside (90%)
Brunei LNG	Brunei	5	7.2	1972	Brunei Government (50%), Mitsubishi Corp. (25%), Shell (25%)
Bontang A,B	Indonesia	2	4.5	1977	Pertamina (100%)
Bontang C,D	Indonesia	2	4.5	1983	Pertamina (100%)
Bontang E	Indonesia	1	2.3	1989	Pertamina (100%)
Bontang F	Indonesia	1	2.5	1993	Pertamina (100%)
Bontang G	Indonesia	1	2.8	1996	Pertamina (100%)
Bontang H	Indonesia	1	3.0	1996	Pertamina (100%)
Tangguh LNG	Indonesia	2	7.6	2009	BP (37.16%), CNOOC (13.9%), Inpex (7.79%), JNOC (5.07%), LNG Japan (7.35%), Mitsubishi (9.92%), Mitsui & Co (2.3%), Nippon Oil (13.45%), Talisman (3.06%)
MLNG I (Satu)	Malaysia	3	8.1	1983	Petronas (90%), State of Sarawak (5%), Mitsubishi (5%)
MLNG II (Dua)	Malaysia	3	7.8	1994	Petronas (60%), State of Sarawak (10%), Mitsubishi (15%), Shell (15%)
MLNG III (Tiga)	Malaysia	2	6.8	2003	Mitsubishi (5%), Nippon Oil (10%), Petronas (60%), Shell (15%), State of Sarawak (10%)
PNG LNG	Papua NG	2	6.3	2014	ExxonMobil (33.20%), JX Nippon/Marubeni (4.70%), Oil Search (29.00%), Petromin (0.20%), PNG Government (16.60%), PNG Landowners (2.80%), Santos (13.50%)
Sakhalin 2 T1,2	Russia	2	9.6	2009	Gazprom (50%), Mitsubishi (10%), Mitsui & Co (12.5%), Shell (27.5%)

Significant regional capacity is under construction, led by Australia. The following projects are scheduled to start up in 2015: Donggi Senoro, Gorgon, Queensland Curtis, Gladstone, Australia Pacific, Kanowit FLNG and Sengkang LNG. These will be followed by Prelude FLNG, Wheatstone and MLNG T9 in 2016, and Ichthys and Rotan FLNG in 2017. Based upon projects that are currently under construction, Australia is projected to produce 75 MMt/y of LNG at 10 projects by 2020. However, high construction costs are such that no additional project sanctions beyond those already committed are expected for the foreseeable future. The future focus in Australia in the short/medium term is likely to be on floating LNG (FLNG), which carries its own execution and cost challenges.

Details of the under construction / planned liquefaction projects in Asia Pacific are included in the table below.

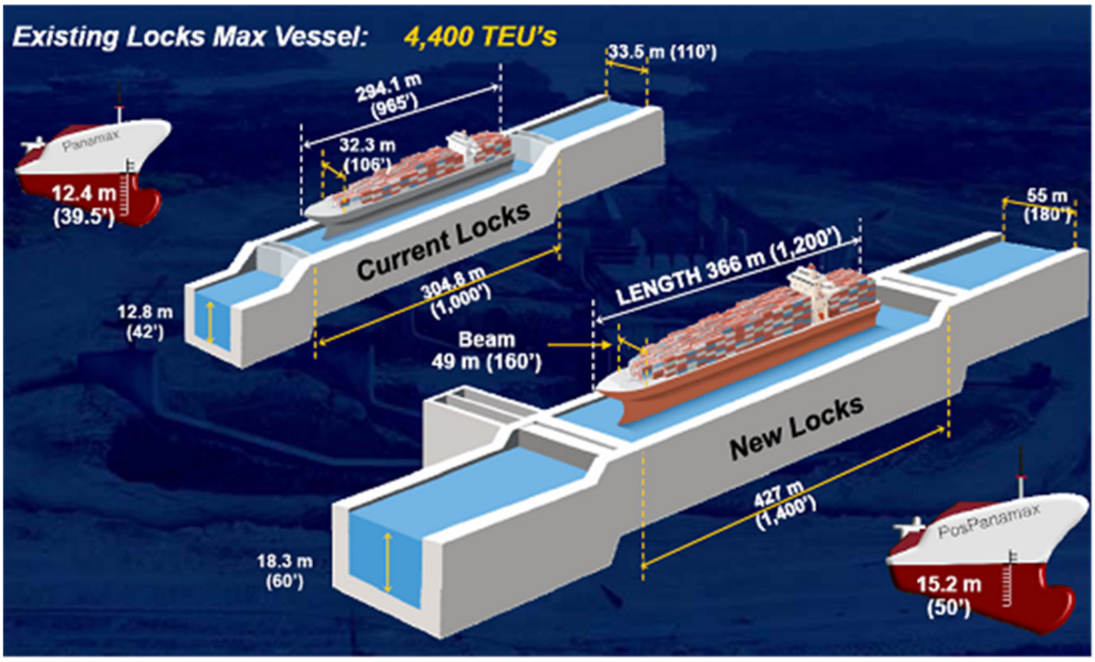
Table H-8 Liquefaction Capacity: Asia Pacific: Planned

Project	Country	Number of Trains	Total Capacity (MMt/y)	Startup	Sponsors
UNDER CONSTRUCTION					
Queensland Curtis LNG	Australia	2	8.5	2015	BG (93.75%), CNOOC (5.00%), Tokyo Gas (1.25%)
Gorgon LNG	Australia	3	15.5	2015	Chevron (47.0%), Chubu Electric (0.42%), ExxonMobil (25.0%), Osaka Gas (1.25%), Shell (25.0%), Tokyo Gas (1.0%)
Gladstone LNG	Australia	2	7.8	2015	ConocoPhillips (42.50%), Origin Energy (42.50%), Sinopec (15.00%)
Australia Pacific LNG	Australia	2	7.0	2015	Kogas (15%), Petronas (27.5%), Santos (30%), Total (27.5%)
Prelude LNG	Australia	1	3.6	2016	Shell (72.5%), Inpex (17.5%), Kogas (10%)
Wheatstone	Australia	2	8.6	2016	Chevron (73.6%), Apache (13%), KUFPEC (7%), Shell (6.4%)
Ichthys	Australia	2	8.4	2017	Inpex (76%), Total (24%)
Donggi Senoro	Indonesia	1	2.0	2015	Mitsubishi (51%), Pertamina (29%), PT Medco Energi Intl. (20%)
Sengkang LNG	Indonesia	4	2.0	2015	EWC (100%)
Kanowit FLNG	Malaysia	1	1.2	2015	Petronas (100%)
MLNG T9	Malaysia	1	3.6	2016	Mitsubishi (5%), Nippon Oil (10%), Petronas (60%), Shell (15%), State of Sarawak (10%)
Rotan FLNG	Malaysia	1	1.5	2017	Petronas (100%)
PLANNED					
PTTEP FLNG	Australia	2	4.3	2018	PTT (100%)
Browse FLNG	Australia	3	12.0	TBD	BP (16.67%), MIMI (14.70%), PetroChina (10.33%), Shell (27.00%), Woodside (31.30%)
Scarborough FLNG	Australia	1	6.0	TBD	BHP Billiton (50%), ExxonMobil (50%)
Tangguh LNG T3	Indonesia	1	3.8	2019	BP (37.16%), CNOOC (13.9%), Inpex (7.79%), JNOC (5.07%), LNG Japan (7.35%), Mitsubishi (9.92%), Mitsui & Co (2.3%), Nippon Oil (13.45%), Talisman (3.06%)
Abadi FLNG	Indonesia	2	4.5	TBD	Inpex (60%), Shell (30%), Indonesian Government (10%)
Vladivostok LNG	Russia	2	10.0	TBD	Gazprom (100%)

H.3.2 Widening of the Panama Canal

As significant development in regard to LNG supply is the widening of the Panama Canal (PC) which is ongoing and due to be completed in 2016. At the present time only around 7% of the global LNG fleet can fit through the PC. These are small LNG vessels, of 40,000 m^3 or less, that are unsuited for very long distance journeys. The expansion is confirmed to allow for the passage of vessels of 366m in length, 49 m wide and with a 15.2 m draft. This would allow the transit of LNG vessels with membrane type tanks of up to 177,000 m^3 to transit the canal. The PC Authority has estimated that the expanded PC will be able to accommodate 89% of the world's LNG carriers by 2015.

Figure H-24 Widening of the Panama Canal
(source: Panama Canal Authority)

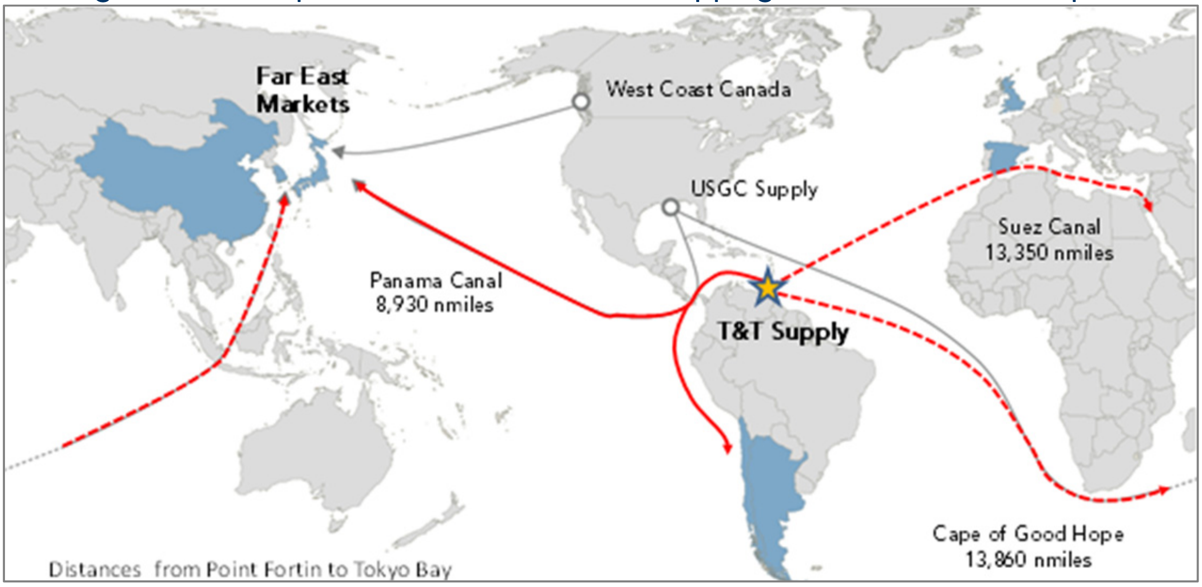


However, a number of existing Moss LNG ships will be too wide to transit the PC. For example, a number of existing 145,000 – 148,000 m^3 Moss LNG vessels have beams of just over 49 m. All existing Q-Flex and all Q-Max vessels will also be too wide to transit the expanded PC. However, vessels with a beam up to 51 m may be allowed through the canal after an initial operational period with the new locks, although this has not been officially confirmed by the PC Authority and timing of any "initial operational period" is not defined. This will allow the utilization of e most (if not all) Q-flex vessels, which typically have a beam of around 50 m. However, existing Q-max ships still be too large to transit the expanded canal, as these vessels have a beam of 53 – 55 m. A number of additional Moss ships may be able to transit the expanded canal in this case, but not all Moss LNG vessels. For example, the specification of a large Moss vessel (177,000 m^3) shows a beam of 52 m. There may be a period when transit is restricted for large LNG carriers with excessive airdraft, including some conventional Moss LNG carriers.

The canal is set to operate with through an allocation of six transit slots in each direction per day for LNG vessels via an auction system. It appears that the six slots will be shared with LPG. LNG is expected to use 4-5 and LPG is expected to need one transit slot every other day. LPG is already transiting the unexpanded PC on smaller ships, then re-loading to a larger ship for the Pacific Ocean crossing to Asia.

The expansion, which is about 85% complete and estimated by the PC Authority to be operational early next year, will cut the roundtrip voyage for LNG carriers from the Caribbean/US Gulf coast to Japan and back through the canal down to around 49 days – a 26 day saving compared with the eastern route through the Suez Canal.

Figure H-25 Impact of Panama Canal on Shipping Distances (T&T to Japan)



The saving in distance would be significant for T&T cargoes to the Far East. The figure above shows the distance from T&T to Japan is 35% shorter using the PC. The canal puts the historically higher value markets of the Far East within easier reach of T&T.

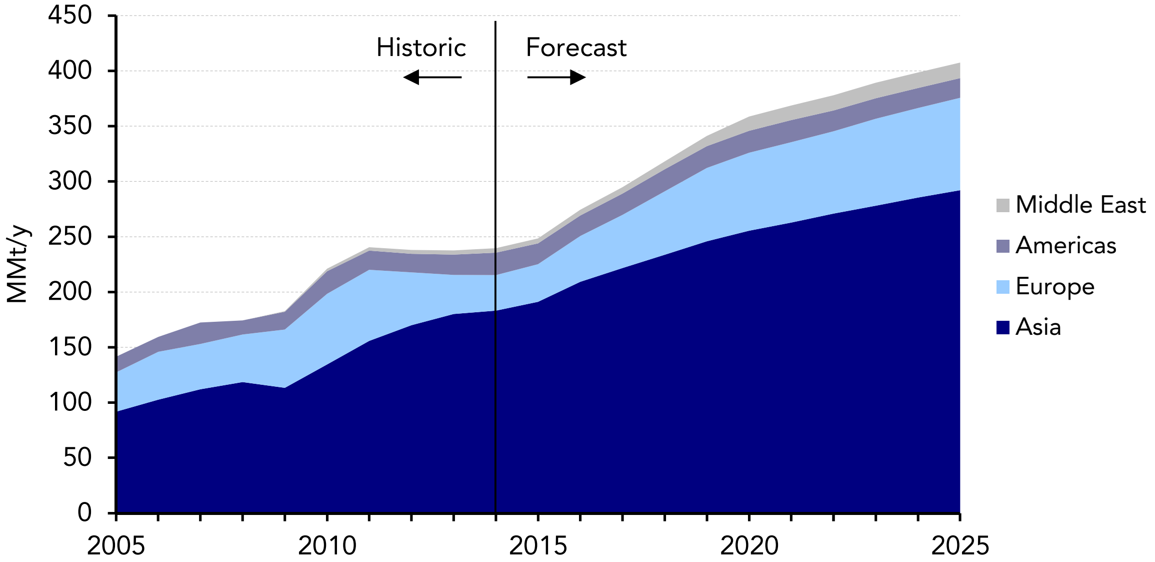
The proposed LNG transit fee works out at round \$650,000 per round trip for a vessel of around 177,000 m^3. One-way laden will cost about \$380,000 and one-way ballast will be \$335,000. On top of this, a \$35,000 booking fee will also be applied each way. The cost has been accepted by LNG shipping companies. It is lower than the Suez Canal's current rates, which are set to be raised on 1 May via a lowering in the discount for LNG vessels from 35% to 25%. For LNG carriers sailing to Tokyo, the voyage from Sabine Pass would be about 35% cheaper via the PC compared to routes via the Suez Canal or around Africa's Cape of Good Hope, with larger ships benefiting from significant economies of scale.

However, the fees could be subject to change. On 27 February 2015 the PC Authority held a public hearing on toll structures. Comments at the hearing and those submitted in writing will be considered before a final proposal for approval is submitted by the PC Authority to the Canal Board of Directors and the Cabinet Council.

H.3.3 LNG Demand

Global LNG demand has grown as the number of importing countries, largely to meet power generation needs, increased from 12 in 2000 to 29 countries in 2014. A combination of growing environmental and regulatory pressures, new LNG production capacity and competitive pricing are projected to drive a strong expansion of LNG imports, which are projected to grow to around 410 MMt/y by 2025 from around 240 MMt in 2014. Growth in LNG demand is anticipated in every major region, except North America (excluding Mexico) where robust growth in domestic shale gas production has almost eliminated imports.

Figure H-26 Historical & Projected LNG Demand: Global

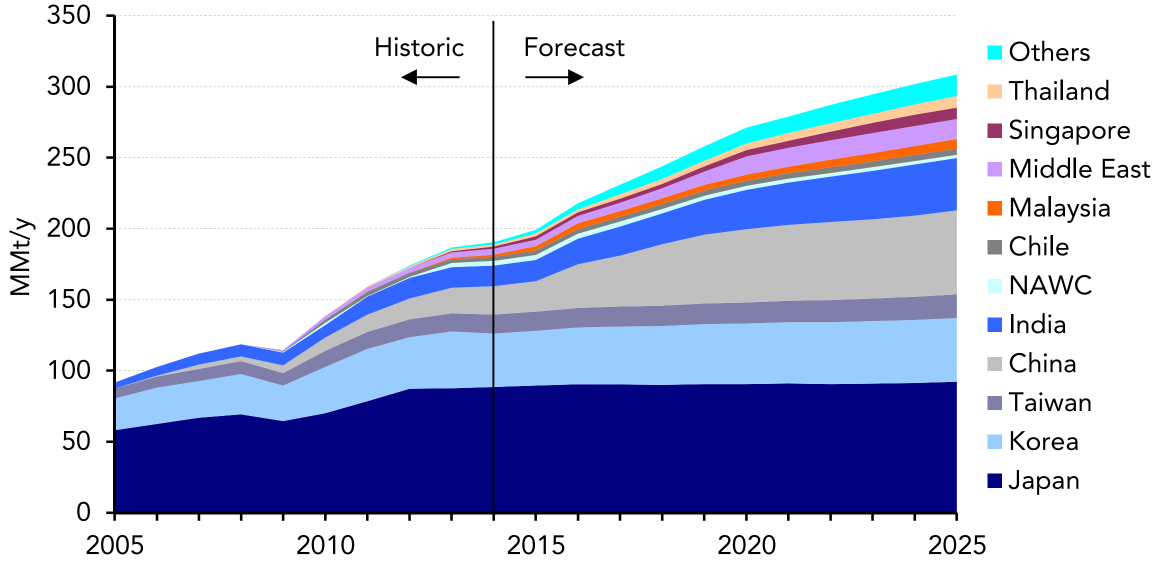


Longer-term, LNG demand will remain a key constraint to supply growth. Even considering our forecast robust demand growth, it is clear that there will only be sufficient markets to support the development of a fraction of the new liquefaction capacity that could potentially developed in North America and East Africa, for example, over the coming decade. This competitive pressure is expected to continue to apply downward pressure on LNG pricing, impacting new suppliers and existing suppliers negotiating contract renewals, such as T&T.

H.3.3.1 Pacific Basin (& Middle East)

Asia remains the foundation of the LNG industry where demand by the three traditional importers, Japan, South Korea and Taiwan (JKT), climbed from 73 MMt in 2000 to around 141 MMt in 2014. Total regional imports are projected to reach ~310 MMt/y by 2025, representing average annual growth of 4.5% between 2014 and 2025, as shown in the figure overleaf. By 2025, JKT, China and India total imports are projected to reach 250 MMt/y. This represents around 104% of the total 2014 global LNG trade.

Figure H-27 Historical & Projected LNG Demand: Asia Pacific



JKT

Japan is the world's largest LNG importer and is expected to remain so. In 2000, Japan imported 54 MMt of LNG, or 52% of global LNG trade, a figure that climbed to 69 MMt in 2008. Following a brief slowing of demand growth due to the nation's struggling economy, Japan's LNG demand surged to 79 MMt in 2011 and to 88 MMt in 2014, following the Fukushima incident. Japanese LNG demand is projected to reach 92 MMt/y by 2025. By far the largest natural gas demand sector in Japan is power generation, which accounts for 70% of demand. With scarce domestic production Japan relies on imported LNG for approximately 90% of its natural gas supply.

South Korea is the world's second largest LNG importer, and Korea Gas (Kogas) is the largest buyer alongside of Japan's Tokyo Electric Power Company (TEPCO). LNG imports surged 75% from 22 MMt in 2005 to 40 MMt in 2013, before declining slightly to 38 MMt in 2014. Poten projects LNG imports into South Korea to grow modestly to reach a level of 45 MMt/y by 2025. South Korean gas demand has large seasonal swings, which presents a significant logistical supply challenge and requires major investments in LNG storage at the import terminals. Kogas is a very active buyer of spot cargoes during the winter months, and the firm has also entered into several medium-term contracts with deliveries heavily weighted to the winter months as well.

In Taiwan power generation is also driving demand for LNG. Taiwan's LNG consumption, while small in scale compared to Japan and South Korea, has expanded by 80% from 7.1 MMt in 2005 to 13.4 MMt in 2014. LNG imports into Taiwan are projected to reach 14.6 MMt/y by 2020 and 17.1 MMt/y by 2025, as Taiwan's use of natural gas in the generation mix is projected to gradually increase from 25% in 2011.

China and India

China and India will require substantial amount of LNG to complement domestic production and pipeline imports. However, India and (to a lesser extent) China are price-sensitive markets with extremely high gas demand potential if prices are competitive. These markets in particular could have significantly higher growth in the event that prevailing LNG prices in future are lower than current projections. On the other hand, higher prices could reduce growth below projected levels. Demand in JKT tends to be less price elastic as they have fewer alternatives to LNG.

Even though China's gas production has increased hugely from 2.7 Bcf/d in 2000 to 13.0 Bcf/d in 2014 it has failed to keep up with consumption, which reached 17.9 Bcf/d in 2014. China has turned to imports to make up the difference. Imports of pipeline gas and LNG reached around 5.7 Bcf/d in 2014, a new record. Pipeline gas imports from Central Asia and Myanmar contributed approximately 3.0 Bcf/d while LNG imports of 2.6 Bcf/d (~20 MMt) rounded out the import picture.

China's gas demand is forecast to quadruple to 53 Bcf/d by 2030. Demand growth is expected to be broadly split between the power, industrial and CRA (commercial, residential and agricultural) sectors. The bulk of this demand is expected to be met by domestic production, which is forecast to rise to ~29 Bcf/d by 2030. However, LNG imports are expected to contribute over 15% to overall gas supply, increasing from 20 MMt in 2014 to 59 MMt in 2025.

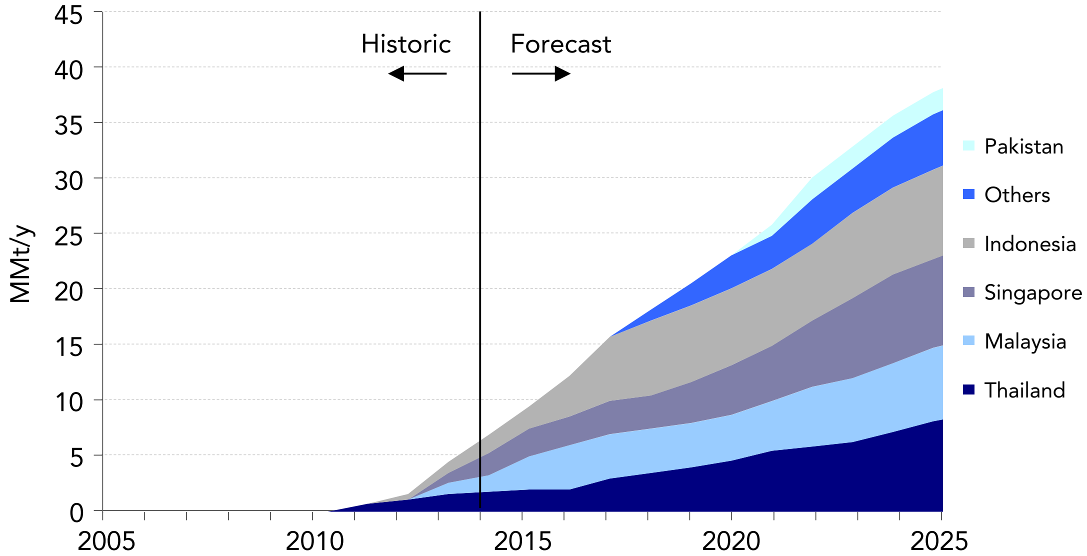
India's gas consumption trebled from 2.7 Bcf/d in 2002 to 6.1 Bcf/d in 2010 buoyed by Krishna-Godavari D6 block (KG-D6) production off India's eastern coast. However, gas consumption subsequently declined to 4.9 Bcf/d in 2014, largely due to a sharp decline in KG-D6 production which is not expected to be reversed. Declining indigenous production prompted gas players to turn to LNG imports, which trebled from 4.1 MMt in 2005 to 13.9 MMt in 2012, before reaching an estimated 14.5 MMt in 2014.

India's natural gas demand is projected to increase at a CAGR of 5.3% to 2030, reaching around 13.5 Bcf/d, with key natural gas consumers being the power, industrial and fertiliser sectors. However, this level of growth will only materialise if price reforms are carried out to encourage domestic production and make additional imports economic. Resulting LNG demand is projected to rise from ~14.5 MMt in 2014 to 37 MMt in 2025.

Other Asian Markets

New buyers are emerging in Asia (e.g. Thailand, Malaysia, Indonesia, Singapore) which although small in absolute terms currently, have the potential to become important LNG markets in the future. Combined import volumes in "niche" Asian markets are projected to increase from an estimated 6.2 MMt in 2014 to around 38 MMt/y by 2025, as shown in the figure below

Figure H-28 Historical & Projected LNG Demand: Asia Niche Markets



- Thailand started LNG import in May 2011, however slow economic growth caused by political turmoil threatens LNG demand growth in the short term. Demand is projected to gradually increase to around 8 MMt/y by 2025.
- Malaysia is turning to LNG to meet a growing gas supply deficit on Peninsular Malaysia. Petronas has completed its first import terminal (Melaka) and is expected to commence operations at its second (Johor) in 2016. LNG imports are projected to reach around 7 MMt/y by 2025.
- Indonesia is also pushing LNG as a means to meet a growing gas supply deficit. LNG is expected to come from indigenous sources, e.g. Bontang, Tangguh, as well as overseas suppliers. LNG imports are projected to reach around 8 MMt/y by 2025.
- LNG is critical for Singapore to meet its future gas demand due to declining pipeline gas imports. A 3.5 MMt/y LNG import terminal was completed and started commercial operations in May 2013. This has since been expanded to 6 MMt/y and plans are in place to increase capacity to 9 MMt/y. LNG imports are projected to grow to ~8 MMt/y by 2025.
- Pakistan finally looks to be making traction in its aim to become an LNG importer, with the outlines of a supply deal reportedly agreed with Qatar.
- There is potential for Vietnam and other countries such as the Philippines to join the LNG importers club in the longer term.

Middle East

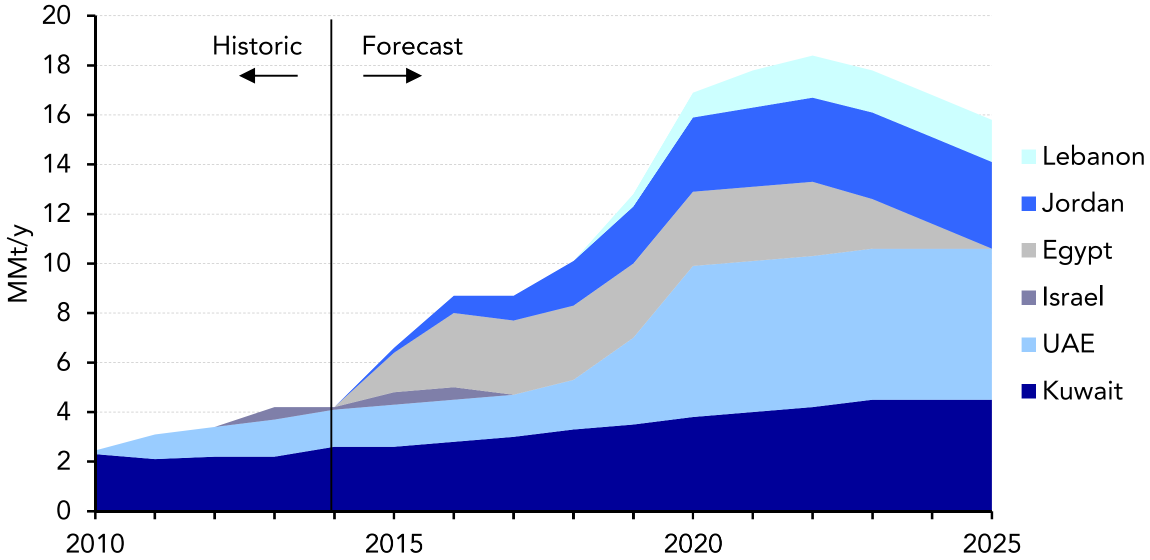
The Middle East contains close to 40% of the total world natural gas reserves and as a result seems an unlikely market for LNG imports. However, gas reserves are not evenly distributed across the region and there is a very limited intra-regional gas pipeline infrastructure. Although many countries in the region are significant gas producers, production has been unable to keep pace with demand growth over recent years. Much of this demand growth has been spurred by heavily subsidised gas prices, which are politically difficult to reform. In addition, low domestic prices have discouraged E&P activity in a number of countries which should have ample reserves to meet current domestic demand, e.g. Egypt. As a result a number of countries are turning to LNG to meet current and future gas supply deficits.

LNG import volumes in the region remain small compared to other major importing regions. Three countries were LNG importers in 2014:

- Kuwait has been importing LNG since 2009 and imported an estimated 2.6 MMt in 2014.
- The UAE's Dubai started importing LNG in 2010, reaching an estaimted 1.5 MMt in 2014. Abu Dhabi's Emirates LNG is expected to be completed by 2018,
- Israel imports LNG as an interim solution until its substantial indigenous gas resources can be fully developed.

Lebanon, Egypt, Jordan, and Bahrain are all advancing plans for LNG imports, but delays continue to plague import terminal development in these countries. As shown in the figure below, regional demand is forecast to peak at around 18 MMt/y post-2020, before declining somewhat as additional indigenous or regional pipeline gas supply sources are developed to meet demand.

Figure H-29 Historical & Projected LNG Demand: Middle East

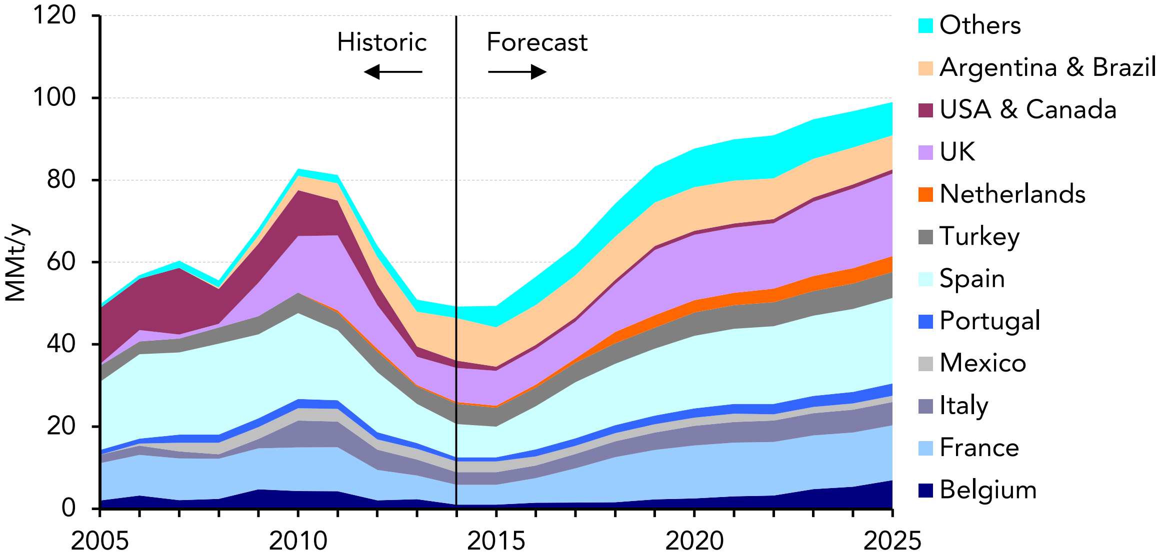


H.3.3.2 Atlantic Basin

While Asia Pacific is the dominant market in LNG trade, the Atlantic Basin is more significant for T&T LNG prospects. Some Atlantic Basin production is sold to buyers in Asia Pacific, but the majority of regional production stays in the region. Still the attraction of what are generally premium prices in Asia should not be underestimated as some Atlantic Basin production promises to continue to flow to East of Suez markets. Indeed, much of the planned US liquefaction capacity is being promoted on the basis of capturing East Asian markets via the PC.

In the shorter term, the large expansion of Australian production over the next few years could push more Qatari LNG back into the Atlantic Basin as European LNG demand recovers. Combined with the large export volumes anticipated from the US, Poten anticipates that the Atlantic Basin market will be highly competitive for suppliers over the coming decade, which could impact the prices that T&T is able to capture for its production.

Figure H-30 Historical & Projected LNG Demand: Atlantic Basin



LNG imports into Atlantic Basin markets have collapsed since 2010/2011 from approximately 80 MMt/y to around 50 MMt/y even as niche markets in South America experienced strong growth in demand. Poten projects prior peaks to be regained by 2020 as UK LNG demand is buoyed by the continued decline in North Sea natural gas production and expected economic recovery on the Continent. At the same time niche market demand continues to grow, even as the North American LNG market has essentially been lost for the foreseeable future as a result of shale gas developments.

North America

At the beginning of the 21st century, North American self-sufficiency in gas was believed to have come to an end and the industry turned to more distant gas resources. Market expectations opened up opportunities for LNG imports and the development of frontier natural gas resources, such as Alaska's North Slope and Canada's Arctic resources. LNG supply sources included T&T, with a number of the supply contracts from ALNG based on supply into the US, and Qatar which established mega-sized liquefaction chains benefitting from economies of scale to deliver large quantities of gas to the distant US market at costs then competitive with indigenous North American gas supplies.

What was not foreseen was the surge in unconventional natural gas production that would reverse the decline in domestic natural gas production, lower HH natural gas prices, and curtail the need for the import of pipeline gas and LNG. Imports of LNG into the US/Canada peaked at 16.2 MMt in 2007 with T&T supplying 9.7 MMt, but have since collapsed to just 1.7 MMt in 2014. This figure is expected to decline further as the process of converting many of the existing import terminals into export plants continues, as discussed previously.

Mexico also turned to LNG imports in the 2000s to meet an expected long-term gas supply deficit, developing import terminals on both the Atlantic and Pacific Coasts. Although Mexico has substantial prospective natural gas resources and is thought to have attractive shale prospects in the Burgos Basin near the US border[1], the national oil company, Petróleos Mexicanos (PEMEX), has focused its limited

[1] The EIA estimates that oil and gas-prone plays extending south from Texas into northern Mexico have an estimated 343 Tcf of risked, technically recoverable and potential shale gas

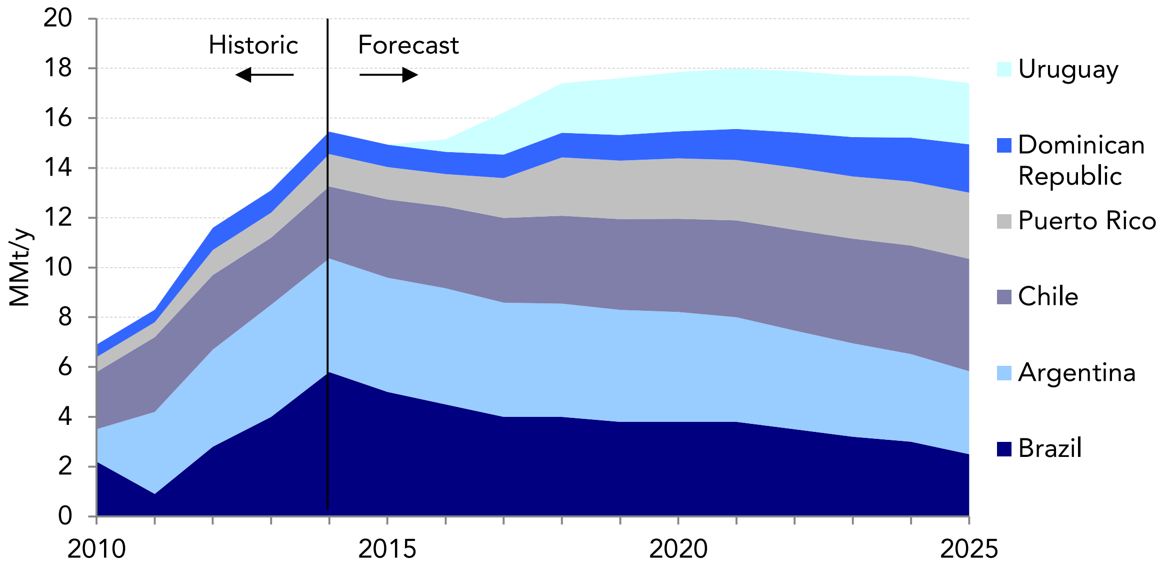
investment capital on oil. As a result, development of the nation's natural gas resources has lagged and Mexico remains reliant on gas imports.

Mexican LNG imports reached an estimated 6.9 MMt in 2014 but are expected to decline over the longer term, provided that additional pipeline infrastructure can be developed and/or sufficient incentives put in place to encourage gas E&P activities, Mexico is likely to follow the US in having little future need for its LNG import terminals. In the long term, these terminals could even become a new source of global LNG supply if domestic gas production meets its potential.

South and Central America

Once considered a niche market for LNG, the region is gaining prominence. Regional LNG imports reached an estimated 15.8 MMt in 2014. During the year, Argentina and Brazil imported 4.9 MMt and 5.9 MMt respectively, followed by Chile at 2.8 MMt. In addition, Puerto Rico imported an estimated 1.3 MMt and the Dominican Republic (DR) an estimated 0.9 MMt in 2014. Much of these volumes originated in T&T.

Figure H-31 Historical & Projected LNG Demand: South and Central America



Argentina is South America's largest natural gas producer and has substantial undeveloped gas reserves. However, the heavily regulated energy sector has limited the industry's attractiveness to private investors, as a result of which a growing gas supply deficit has developed. This has led to a growing dependence on natural gas imports in the form of pipeline gas from Bolivia and LNG. Provided that a more business-friendly approach is taken by the government to the E&P sector, which there is already some sign of, Poten expects LNG imports into Argentina to decline slowly from current levels over time.

Brazil relies on LNG to meet seasonal gas shortages for power generation when rainfall is insufficient for hydroelectricity to meet power demand. As a result, Brazil's LNG imports have fluctuated significantly from year to year. For example, LNG imports declined from 2.3 MMt in 2010 to just 0.9 MMt in 2011, when there was ample rainfall. Imports then rebounded to 2.4 MMt in 2012 and to 4.0 MMt in 2013. Similarly to Argentina, Brazil's need for imported LNG is projected to decline over time as indigenous supply ramps up, primarily from the offshore Santos Basin.

The natural gas market in Chile peaked at around 0.8 Bcf/d in 2006 before declining to 0.3 Bcf/d by 2008 following the cut off of deliveries from Argentina. After the introduction of LNG, the market has gradually recovered to around 0.5 Bcf/d as of 2014. As it lacks indigenous resources but has substantial energy demand at relatively high prices, Chile has the strongest potential for growth in LNG imports in the region, which are projected to reach around 4.5 MMt/y by 2025. However, Chile's position on the Pacific coast makes it less attractive to T&T as a potential market.

Uruguay is developing its first LNG import terminal which is expected to begin operations in 2015. The 2.7 MMt/y capacity project is designed to provide gas to complement the variability of hydroelectric capacity for power generation. However, Poten expects LNG imports into Uruguay to only ramp up relatively slowly to around 2 MMt/y as the market in Uruguay is only thought to be sufficient to absorb around half of the terminal's planned capacity. A further market opportunity for the project is to reverse the flow of an existing pipeline from Argentina, through which supply has been dwindling over recent years as a result of production declines in Argentina.

Puerto Rico is currently developing its second LNG import terminal, which is expected to commence operations offshore the south coast of the island by 2016. This project is designed to convert switch fuel consumption for power generation away from fuel oil to lower cost natural gas. As a result, Poten expects LNG imports to increase to increase to around 2.4 MMt/y by 2018 from around 1 MMt/y currently, before increasing only slowly thereafter.

The DR is also an LNG importer. Both Puerto Rico and the DR are supplied from T&T's ALNG project. The only import terminal in the DR was initially extremely underutilised, with just a couple of cargos delivered per year in 2003 and 2004, largely because Dominican electric distributors failed to pay for the electricity produced by the power plant. This in turn has forced the project developer, AES, to cancel contracted LNG deliveries from BP. Deliveries were resumed in 2007 and have climbed to around 0.9 MMt/y, close to the nameplate capacity of the terminal. There is potential for increased LNG imports into the DR, but this will require expansion of the existing terminal or development of a new terminal. Poten forecasts LNG imports to increase to around 2.0 MMt/y by 2025.

Clearly regional markets present an obvious opportunity for T&T, particularly with the forthcoming expiry of existing LNG supply contracts from ALNG. However, considering the huge volume of supply now anticipated from the US Gulf Coast, it is clear that T&T will face substantial competition to capture these markets and will have to compete on price with supply from the US.

H.3.3.3 Europe

The European natural gas market is the second largest regional market globally, with demand in the European area (EU-28 plus Turkey) standing at around 50 Bcf/d in 2014. The market is largely mature and slowly growing/declining apart from in the emerging market of Turkey and in new gas-to-power markets.

Indigenous natural gas production in Western Europe, in particular the North Sea, has been in steep decline. Countries in North West Europe are becoming more dependent upon imports, both via pipeline and LNG, and are competing for supplies on both a European and a global scale. European markets, in particular Spain, have traditionally been important for T&T LNG exports. In 2014, European imports of LNG from T&T totalled around 2.5 MMt, with Spanish imports of 1.6 MMt accounting for around two-thirds of the European total imports from T&T.

The liquid markets in North West Europe are being used as a balancing point for the global LNG market. With reduced oil prices and the reduction in the demand for LNG seen in countries such as Japan and

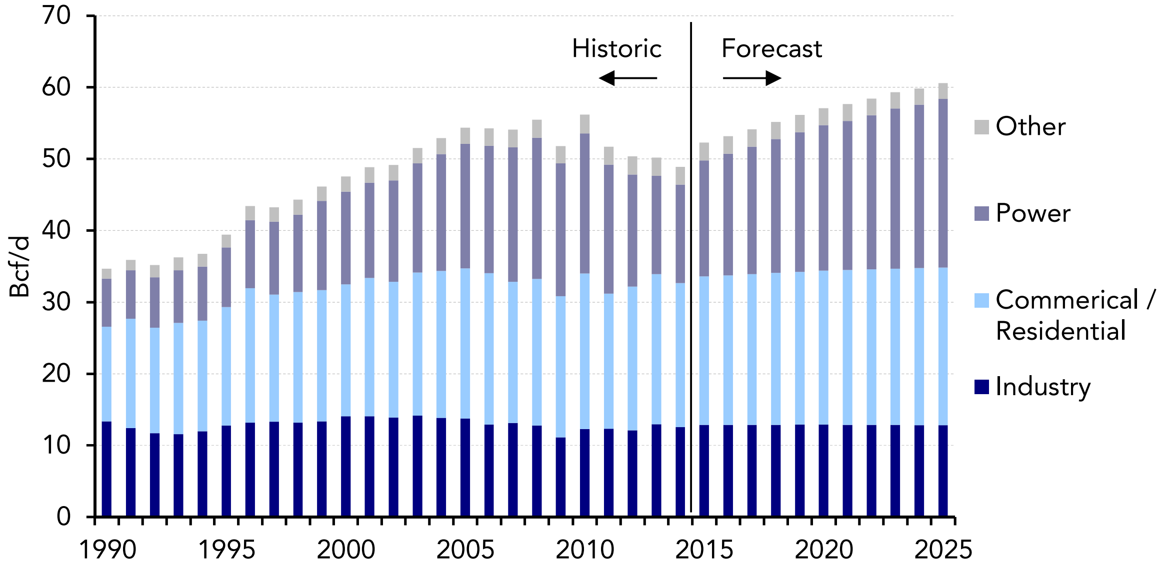
Korea, LNG previously destined for the Asian market has been headed back into the European market as to balance the global market.

European Gas Demand

Natural gas demand across Europe has been depressed in recent years as a result of tough economic conditions, the development of renewable sources of electricity and competition against coal. Combined with the low cost of emissions, natural gas has been pushed down the power generation queue by cheap coal prices and high renewables output. As a result, aggregate EU-28 gas demand fell from a peak of around 56 Bcf/d in 2010 to around 49 Bcf/d in 2014.

It is expected that with economic recovery, European (EU28 and Turkey) natural gas demand will rebound to the 2010 peak by 2019, with demand reaching approximately 61 Bcf/d by 2025 as shown in the figure below.

Figure H-32 Historical & Projected European (EU28 + Turkey) Gas Demand by Sector



The power sector has been central to the recent malaise and future growth of European gas demand. Gas-to-power demand fell sharply between 2010 and 2014 due to a number of factors: reduced electricity demand due to economic recession; cheap coal and emissions prices, making natural gas to lose price competitive to coal; and large increases in renewable generation.

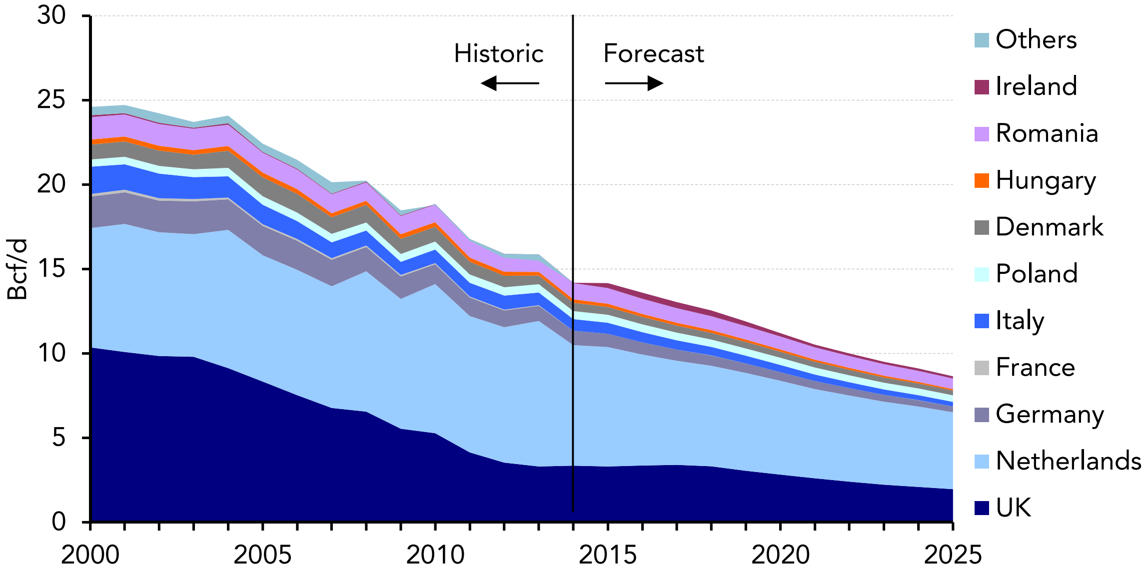
However the EU Industrial Emissions Directive will mean that many ageing coal plants will close down in the next few years. In addition to this, opposition nuclear power in some parts of Europe can only have a positive effect and promises to boost the role of gas for power generation and within the overall energy mix. In Germany, the political commitment to ending nuclear power is likely to push up demand for alternative sources of energy, although the use of gas in power generation is being restricted by the development of renewables and emissions-compliant coal-fired plants. Elsewhere, such as France, Belgium and the UK, the graduated phase-out of some older nuclear plants will be an important driver to natural gas demand. With long lead-in times new nuclear power generation is not expected to be of any real significance in terms of the overall power generation mix before 2020 at the earliest.

There has been a drive in the development of renewables sources of power generation, such as wind and solar, mainly in countries such as UK, Netherlands, Germany and Spain. While this has pushed gas further down the fuel mix for the generation of power, the use of renewables is intermittent and the uncertainty that this brings with it increases the need for a fast-acting, cleaner, back-up solution that natural gas fired power plants provide.

European Gas Supply

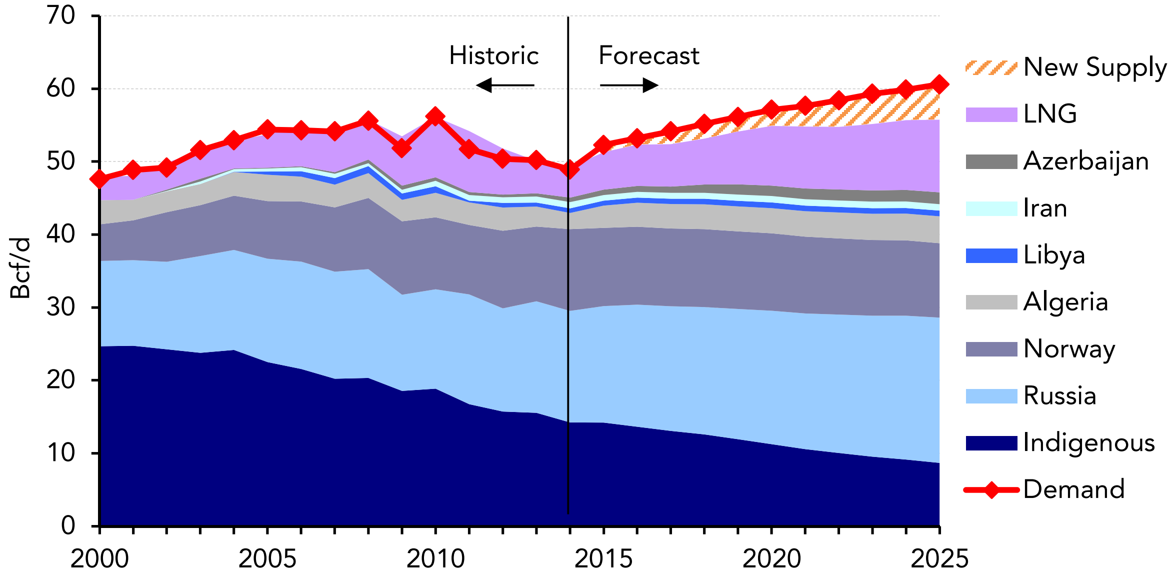
The decline in Western European natural gas production has been dramatic, from ~25 Bcf/d in 2000 to around 14 Bcf/d as of 2014. The decline in indigenous production has created strong demand for pipeline natural gas, particularly from Russia, and for LNG.

Figure H-33 Historical & Projected European Indigenous Gas Supply



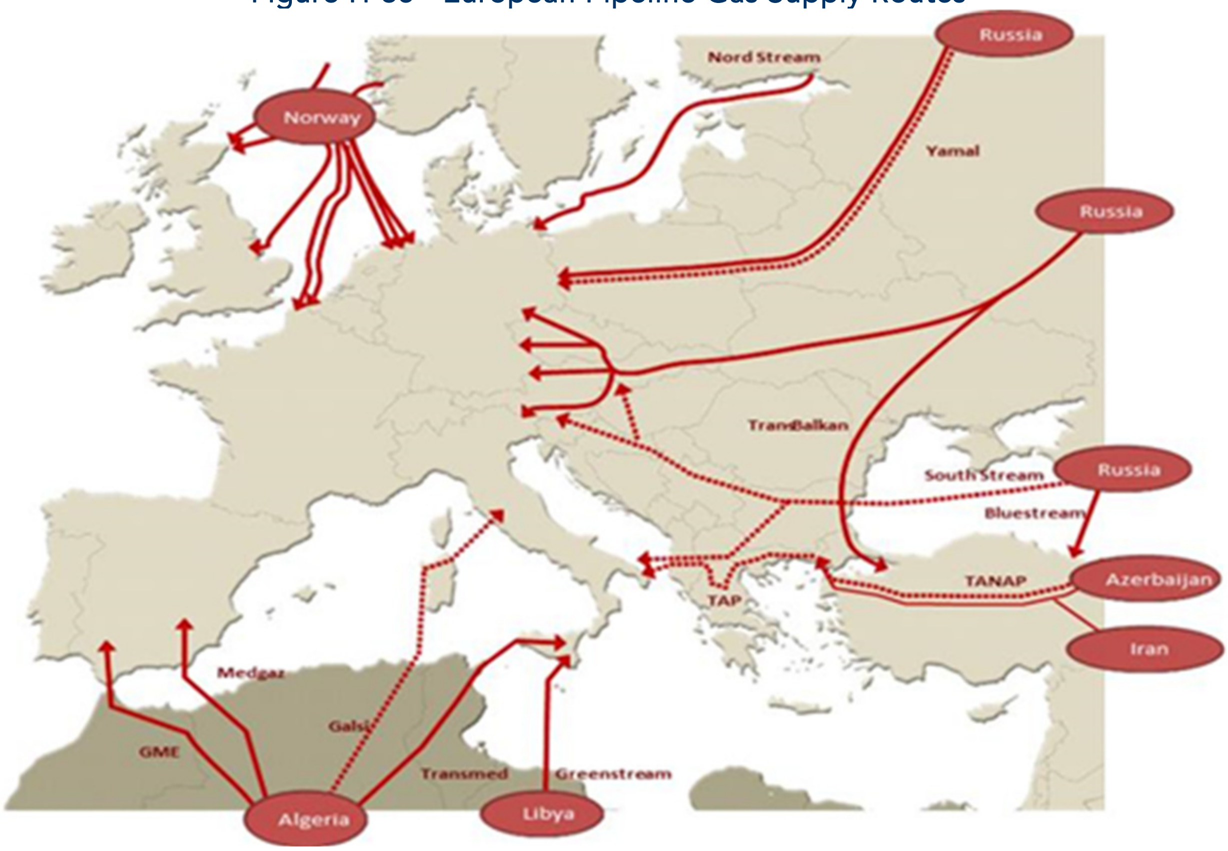
Russia and Norway dominate the market as the main suppliers of pipeline natural gas into Europe. In 2010 the two combined provided 83% of all Europe's pipeline imports. The remainder comes mainly from Algeria and Libya, with Azerbaijan's Shah Deniz 2 due to start exporting to Europe, via Turkey and Italy, later on this decade.

Figure H-34 Historical & Projected European Gas Supply



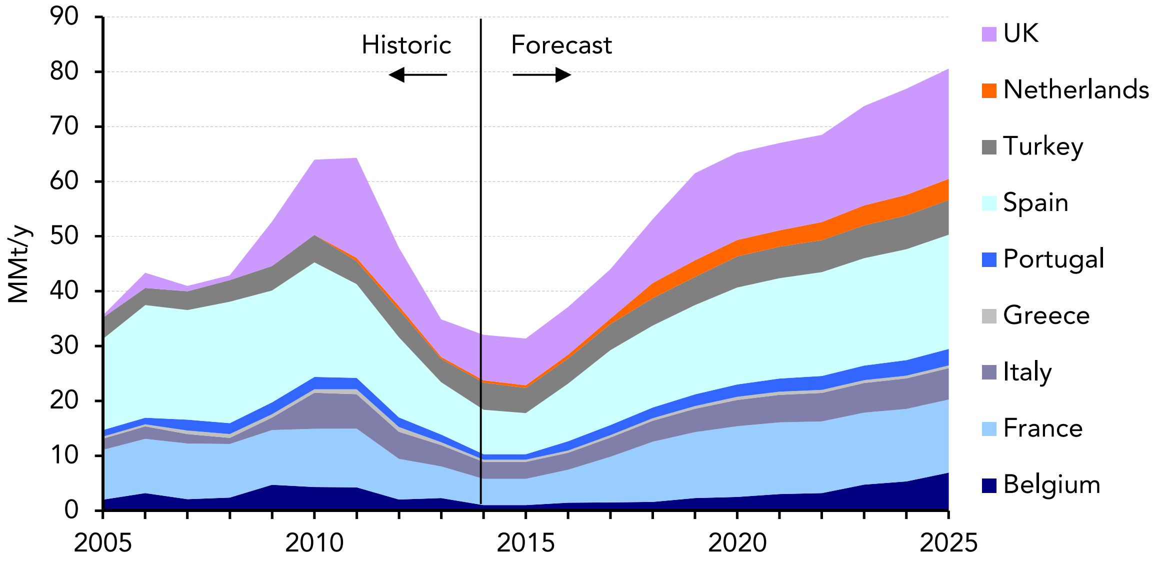
There is highly developed pipeline infrastructure to deliver natural gas into Europe. The pillars of this system have been pipelines from Russia, Norway and North Africa, primarily Algeria. More recently there have been efforts to link in Central Asian gas. A significant share of Russian natural gas flows through Ukraine and Russia is threatening to divert these volumes through a southern route.

Figure H-35 European Pipeline Gas Supply Routes



LNG imports into the EU peaked at around 64 MMt/y (8.4 Bcf/d) in 2011 before collapsing by half to around 32 MMt (4.2 Bcf/d) in 2014 due to the decline in European gas demand and the strength of demand in Asia by buyers willing to pay premium prices.

Figure H-36 Historical & Projected LNG Demand: Europe (EU28 + Turkey)



As the UK and the rest of Europe become more heavily dependent upon imported supplies of natural gas, aggregate LNG imports into the three largest NW European markets (UK, Spain and France) are projected to reach around 54 MMt/y (7.1 Bcf/d) by 2025. However, the UK currently has no long-term contracts for LNG supply in place (although companies such as BP, Centrica and BG, with access to regasification into UK, have recently signed up to long term supplies of LNG out of US) and will be competing on a global scale for available LNG supply.

European Gas Trading Hubs

North West Europe has developed deep and liquid traded markets in gas. The UK's National Balancing Point (NBP) which has generally been considered to be the most liquid trading point in Europe and most relevant for LNG as the UK has a very large capacity to receive LNG through its import terminals (5 Bcf/d) and has good interconnectivity with the rest of the European gas market (pipelines from Norway, the Netherlands and a bi-directional interconnector with Belgium). The Netherlands' Title Transfer Facility (TTF) has powered ahead over the past few years and is becoming the dominant pricing point for continental European natural gas.

H.3.4 LNG Pricing

Since natural gas developed as a regional business, gas and LNG pricing regimes and formula structures are developed to meet local constraints and the specificities of the end-user markets for gas. Accordingly, unlike the oil market, and although the situation may evolve in the future, gas does not currently have an international benchmark price. However, similarities lie in the extremely important influence that competing energies, and in particular crude oil and oil products, have on gas prices on all the regional markets. Natural gas does not have a captive market, and is always in competition with other energies: electricity, gas-oil and LPGs in the residential/tertiary sectors, electricity, coal and heavy fuel oil in the industrial sector, and coal, fuel oil and nuclear power in the power sector. Thus its price cannot deviate too much from competing energies, which always offer a satisfactory replacement.

Generally speaking, the key regional price mechanisms are as follows:

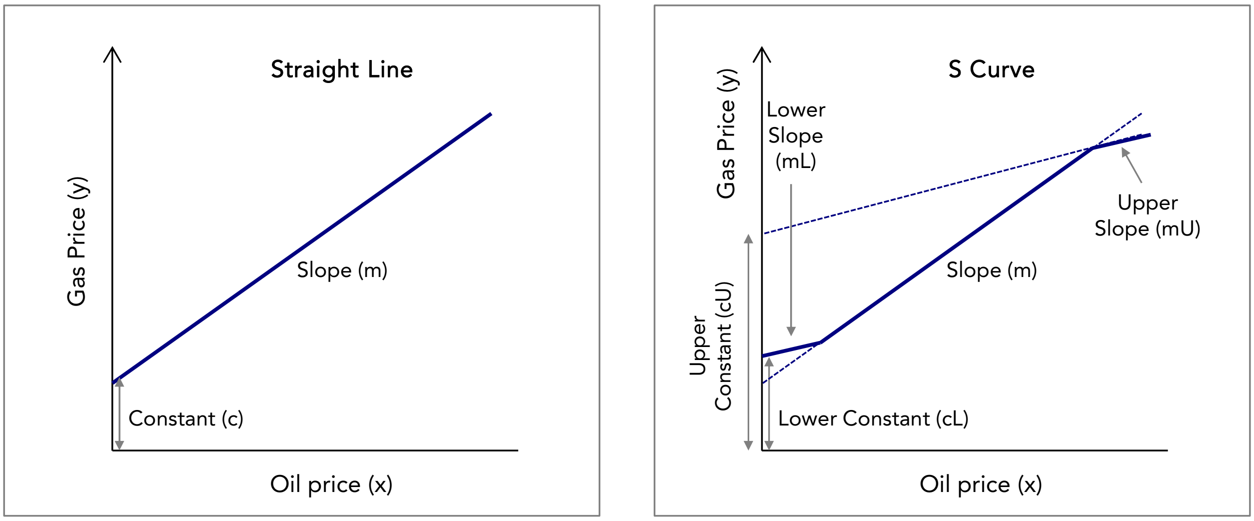
- Asia – indexation to crude oil.
- North America – supply and demand fundamentals.
- Europe – indexation to crude/oil products or, increasingly, based on supply and demand fundamentals.

H.3.4.1 Asia

Gas pricing in North East Asia has historically been set by oil-linked LNG imports. The majority of LNG trade flows in Asia are sold under long-term contracts with price related by formulae to a time averaged value of crude oil (usually over 3 or 6 months). This reflects the fact that there are no liquid markets or associated hubs in Asia and the role of oil and liquid products as, historically, the principal competing fuels.

The crude oil reference is typically the Japan Customs Cleared or the "Japanese Crude Cocktail" (JCC) price, the monthly average price of crude imported into Japan, rather than Brent. The coefficient linking LNG prices to oil prices differs between contracts based on the terms bilaterally negotiated by the buyer and seller. Some contracts also contain price ceilings and floors or an 'S' curve which moderates the more extreme oil price impact on the LNG price, as shown in the figure below.

Figure H-37 Example S-Curve Mechanism



Each contract pricing formula represents a 'snapshot' of the negotiated view of buyer and seller as to how the future LNG price should respond to oil price. Over time the differences in formulae relating LNG prices to oil price have led to a wide range of LNG contract prices which typically get corrected in periodic (~5 years) price reviews, although not all contracts contain such review provisions.

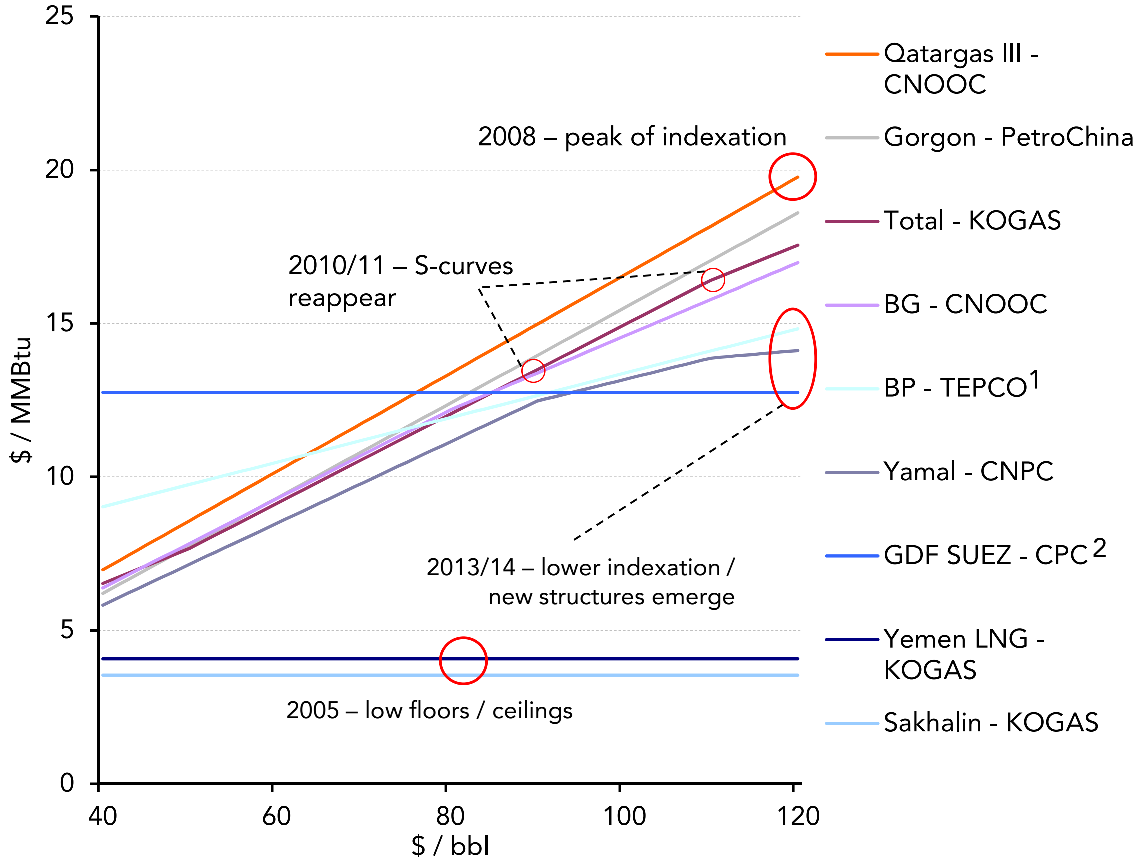
Although indexation to crude oil of around 15% has dominated the 40 year Asian industry history, long-term price have always responded to market conditions and have varied significantly over the past decade, as shown in the figure overleaf.

- In 2005, during a buyers' market and at a time of \$40-50/bbl oil prices, buyers were successfully able to push for LNG price caps (and floors), whereby oil-linked prices were capped above oil prices of \$25 – 40/bbl.

- By 2007/8, as market power switched towards sellers and oil prices rose, straight line relationships became the norm with indexation levels to crude oil of >0.15.
- Driven by CBM-based projects in Australia seeking markets, 2010/11 saw the reintroduction of s-curves in contracts, with upper inflexion points at \$80 - \$110/bbl.
- Reflecting increasing buyer power, a deal between Yamal LNG and CNPC in 2014 saw reported oil indexation of ~0.133 and more than one inflexion point to substantial reduce indexation at higher oil prices.

In response to the emergence of LNG exports from the US and a desire from buyers to procure LNG on a HH-linked basis, some recent deals have been done that are fully HH-linked or offer a hybrid between oil and HH indexation.

Figure H-38 Asian L-T LNG Contract Price Development, 2005 - 2014



1 Hybrid with 50% oil and 50% HH indexation. Assumes \$5/MMBtu HH
2 100% HH indexation. Assumes \$5/MMBtu HH

Asian importers also purchase spot LNG cargoes to supplement contracted supplies. An Asian LNG spot price, "JKM" produced by Platts, has emerged and has been used in contracts although there remain questions as to the extent to which it truly reflects market trading.

H.3.4.2 North America

Gas prices in the US are in the first instance driven by gas-on-gas competition and are discoverable at the many regional trading hubs. The best known is HH which is viewed as the marker for US natural gas prices and is the world's largest and most liquid gas market index. The US has a 'porous' gas trade border with Canada and Mexico, both of which have prices influenced by the US market.

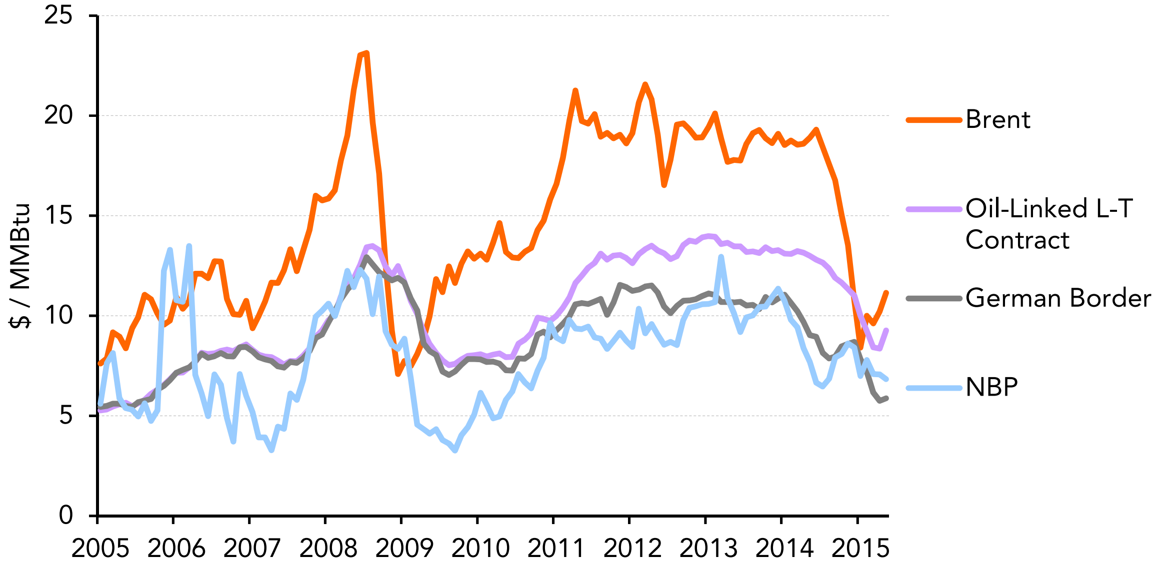
H.3.4.3 Europe

The UK is the only fully liberalised, liquid gas market in Europe. Liberalisation began with the 1986 Natural Gas Act, which set the necessary regulatory framework. UK gas prices at the NBP are set by gas-on-gas competition. The NBP is a virtual hub, unlike US or European equivalents such as HH or the Zeebrugge Hub in Belgium. The NBP was introduced with the Network Code, which is a set of governing rules for the UK gas market that all shippers must adhere to. The NBP established an entry/exit system which replaced point-to-point transport pricing. It should be noted that NBP, while considered to be the most liquid gas trading point in Europe, has only about one tenth of the liquidity of HH.

With the exception of the UK market, Europe began the 2000s with a market structure dominated by long-term, oil-indexed contracts for its pipeline and LNG imports, and also its domestic production. Pipeline gas purchased under long-term contracts from Russia and North Africa has historically been priced according to formulae which include six to nine month rolling averages of gasoil and fuel oil prices. A typical average mix in the basket of fuels used was as follows: 70% Gasoil; 10% LSFO; 20% fixed. The pricing terms are subject to periodic review (typically every three years) and may be amended through negotiation. Historically, pricing terms equivalent to 9 to 11% of Brent were common in European oil-linked gas contracts.

Gas market liberalisation in Continental Europe has been a slow process. However, as a result of the gas demand reduction caused by the economic recession and the rapid growth of LNG trade, oil-indexed contracts are slowly but surely being replaced by gas hub indexation, mainly NBP and TTF (Netherlands). As a result, the German border average price, historically taken as a proxy for oil-linked gas prices, and hub prices have converged, as shown in the figure overleaf. Nevertheless, many legacy oil-indexed pipeline gas supply contracts still remain.

Figure H-39 German Border Price and NBP Convergence



Currently in Southern Europe gas remains mostly priced against oil and/or oil products, partly reflecting the traditional competing fuels of gas and also the lack of gas market liquidity within these markets. Over the past few years a number of contracts have either been negotiated (or renegotiated) to include gas market indexation, mainly driven by the recent downturn in gas demand.

H.3.4.4 Latin America

The market for LNG in Latin America is relatively small and immature and, as such, there is no clear template for pricing deals. To date most LNG deals have been spot or short-term, to buyers with limited alternative options, and have therefore tended to be priced at a level that reflects alternative opportunities for sellers in absolute terms. This has led to deals being priced on the basis of HH+ and NBP+ as well as oil-linked deals. Chile is increasingly becoming a HH-linked market.

H.3.4.5 LNG Price Developments

Global Pricing

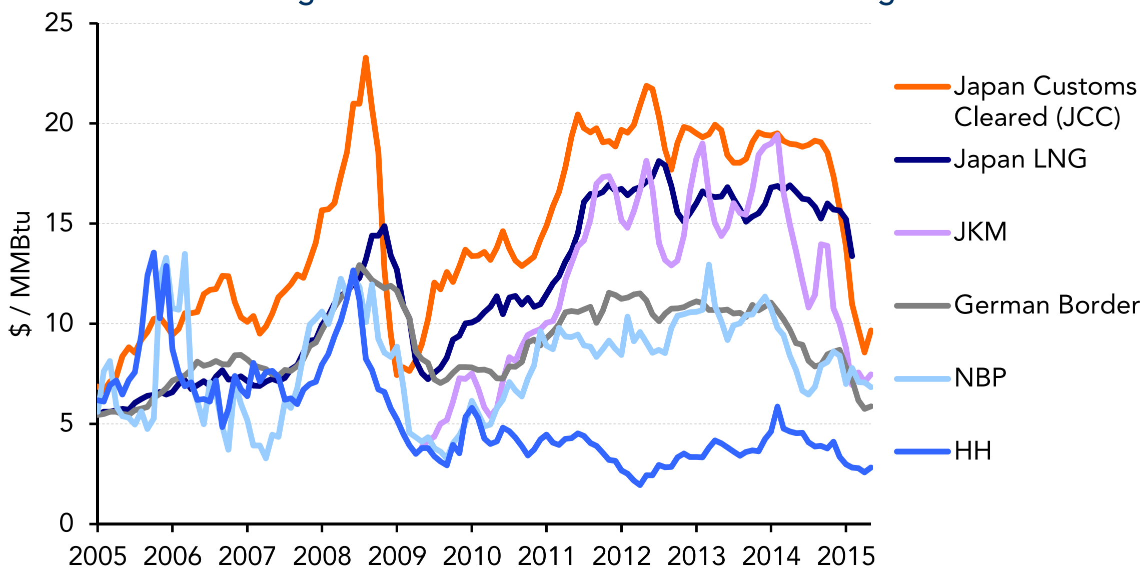
Until the very recent steep oil price decline, global gas prices have been increasingly divergent, as shown in the figure below. A decade ago regional gas prices, although set on different bases, were similar in value at around $4-6/MMBtu. Other than in the US, gas prices have risen substantially since then, although NBP and JKM prices have declined markedly since the beginning of 2014.

A key factor in the changes in gas prices was the increase in oil prices from ~$30/bbl in 2004 to ~$110/bbl in 2013:

- Oil and gas prices in the US have decoupled as a result of shale gas developments.
- Asian prices have been sustained well above European (and North American) levels.

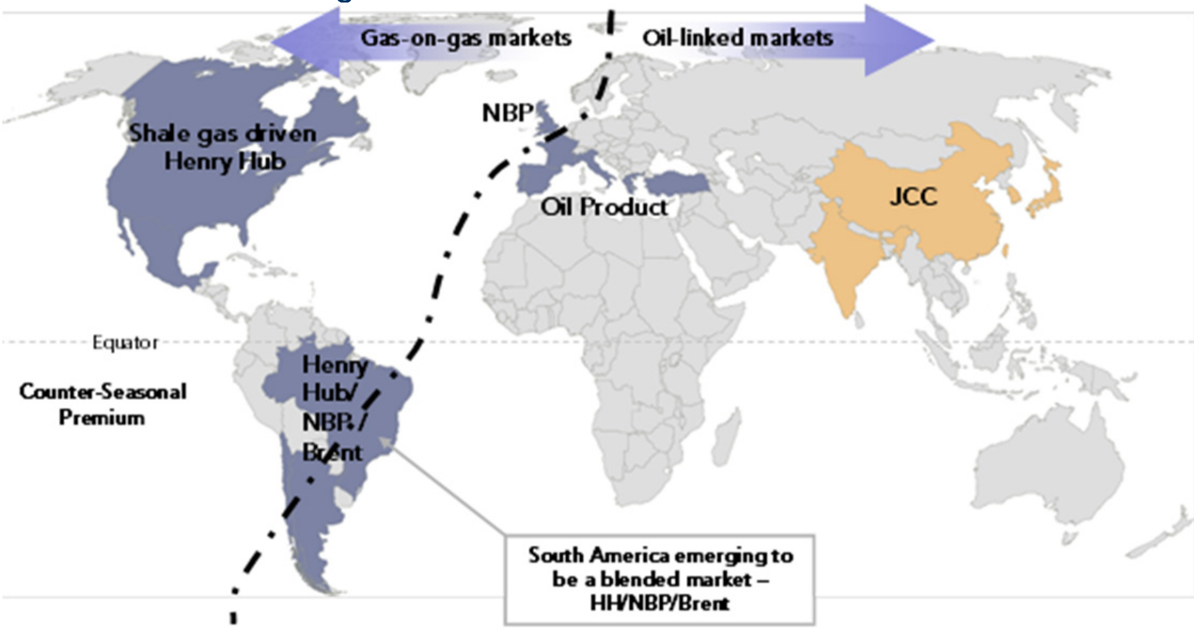
Recent lower oil prices will feed through to oil-indexed LNG prices after a time lag (3 months is typical in LNG SPAs).

Figure H-40 Global Oil & Gas / LNG Pricing



As shown in the figure below, gas markets remain compartmentalised.

Figure H-41 Global Gas Price Formation

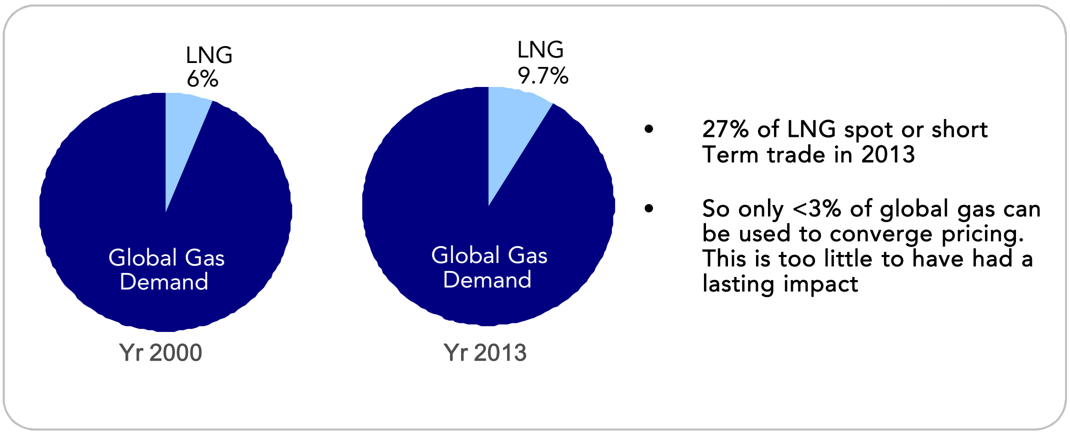


At the present time regional gas prices remain highly divergent, although this will reduce if oil prices remain low for a prolonged period.

As shown in the figure below, with flexible LNG trade at less than 3% of global gas demand, LNG trade has been insufficient to cause price convergence. In any truly commoditised market this divergence would not be sustainable over an extended period, however there is insufficient fungible gas (LNG) available to arbitrage the different regions.

Figure H-42 Flexible LNG Supply

(source: Poten, BP Statistical Review of World Energy)



Recent Contract Pricing

As shown in the table below, there has been some downward pressure on Asian long-term prices of late.

Table H-9 Recent Asian LNG SPA Pricing[2]

Year Signed	Supply Project	Seller	Seller Country	Buyer	Buyer Country	Volume (MMt/y)	FOB / DES	Start Year	Base Term (years)	Reference Crude Oil / Hub Gas	% Crude / Hub Price	Fixed Element ($/MMBtu)	S-Curve: Yes/No?
2013	N/A	Eni	Portfolio	KOGAS / Chubu EP	S. Korea / Japan	0.44	DES	2013	4	Crude Oil	0.13	1.35	No
2013	Tangguh	Tangguh	Indonesia	KOGAS	S. Korea	1.0	DES	2013	4	JCC	0.143	0.50	No
2013	N/A	BG	Portfolio	GSPC	India	1.25 (2.5 option)	DES	2015	20	Crude Oil	0.138	-	Yes
2013	N/A	BP	Portfolio	CFE / Pemex	Mexico	0.3	DES	2013	1.5	JKM	1.000	1.50	No
2013	N/A	BG	Portfolio	CNOOC	China	5.0	DES	2015	20	JCC 60% / HH 40%	JCC 0.139, HH 1.24	JCC 1, HH (2.52+premium) + shipping	No
2013	N/A	BG	Portfolio	GNL Quintero	Chile	1.7	DES	2009	21	HH	1.15	3.70	No
2013	N/A	BG	Portfolio	Endesa	Chile	0.4	DES	2013	17	Brent	0.1	Unknown	No
2013	N/A	Gas Natural	Portfolio	KOGAS	S. Korea	0.48	DES	2014	2	JCC	0.143	0.50	No
2013#	MLNG Tiga	Petronas	Malaysia	KOGAS	S. Korea	2.0	DES	2008	20	JCC	0.135	0.50	No
2013	N/A	Gas Natural	Portfolio	KOGAS	S. Korea	0.48	DES	2014	2	JCC	0.143	0.50	No
2013	N/A	GDF Suez	Portfolio	CPC	Taiwan	0.8	DES	2018	20	HH	1.25	6.25	No
2014	Pluto	Woodside	Australia	Chubu Electric	Japan	0.50	DES	2014	3	JCC	Low 0.14s	0.50	No
2014	NLNG	GALP	Nigeria	Petronas	Malaysia	0.4	FOB	2015	3	Brent	0.11	4.00	No
2014	N/A	Shell	Portfolio	KPC	Kuwait	1.30	DES	2014	5	Brent	Low 0.14s	-	No
2014	N/A	BP	Portfolio	KPC	Kuwait	0.65	DES	2014	5	Brent	~0.14	-	No
2014	N/A	Shell	Portfolio	Chubu Electric	Japan	0.76	DES	2017	17	Japan Landed Cost (JLC)	1.000	-	No
2014	N/A	Shell	Portfolio	Chubu Electric	Japan	0.76	FOB	2014	2	JCC	0.15	-	No
2014	Bontang	Pertamina	Indonesia	BP	Portfolio	0.76	FOB	2014	2	JCC	0.149	0.00	No
2014	Yamal LNG	Yamal LNG	Russia	CNPC	China	3.00	DES	2017	20	JCC	0.132 -	Unknown	Yes
2014#	ADGAS	ADGAS	UAE	Tokyo EP	Japan	4.70	DES	1994	25	JCC	0.147	0.53	No
2014	Sabine Pass	Cheniere	USA	Kansai EP	Japan	0.35	DES	2016	2	HH	1.30	8.00	No
2014	N/A	BP	Portfolio	Tokyo EP	Japan	1.20	DES	2017	17	JCC 50% / HH	JCC 0.145,	HH 6.5	No
2015	N/A	Trafigura	Portfolio	CFE	Mexico	0.50	DES	2015	1	JKM	1.00	0.15	No

#Price review of existing contract

Recent deals include lower oil indexation (14% of crude oil or less, versus the 15% level that has dominated the history of the industry), HH indexation or hybrid constructs. Growing supply competition, particularly from planned North American exports, is prompting some sellers to offer long-term hybrid pricing with an element of hub indexation alongside the traditional oil link.

The advent of the US liquefaction projects and the subsequent sale of long-term LNG has introduced the use of Henry Hub as a pricing reference for long-term LNG, with prices typically being set at 115% HH plus a constant (for example $3/MMBtu at Sabine Pass (with the exception of the first deals with BG and Gas Natural which were <$2.50/MMBtu) and $3.50/MMBtu at Corpus Christi), which is representative of the liquefaction costs incurred by the supplier.

Future USGC capacity should have a liquefaction charge of $3.50/MMBtu or less:

- Brownfield projects, i.e. conversions of existing import terminals, should be able to charge $3/MMBtu or less and still make attractive returns.
- Greenfield projects are likely to require a higher figure along the lines of the $3.50/MMBtu being charged at Corpus Christi.

[2] Information contained in the table above is based on market intelligence and is provided without warranties of any kind, whether expressed or implied. Information is not to be re-produced without consent of Poten & Partners. Copyright 2015.

There are few recent price benchmarks for long-term sales into the Atlantic Basin. With the exception of a deal between Yamal LNG and Gas Natural, recent Atlantic Basin deals have been largely restricted to short-term arrangements (1-2 years or less). The Yamal-Gas Natural deal reportedly has a 60%/40% hybrid price at 12% of Brent/97.5% of NBP. The most recent short-term deal (2 years) was reportedly at ~14% of Brent in January 2015, involving 72 cargoes to Egypt's EGAS from a combination of Vitol, Noble Group, Trafigura and BP.

Table H-10 Recent Atlantic Basin LNG SPA Pricing[3]

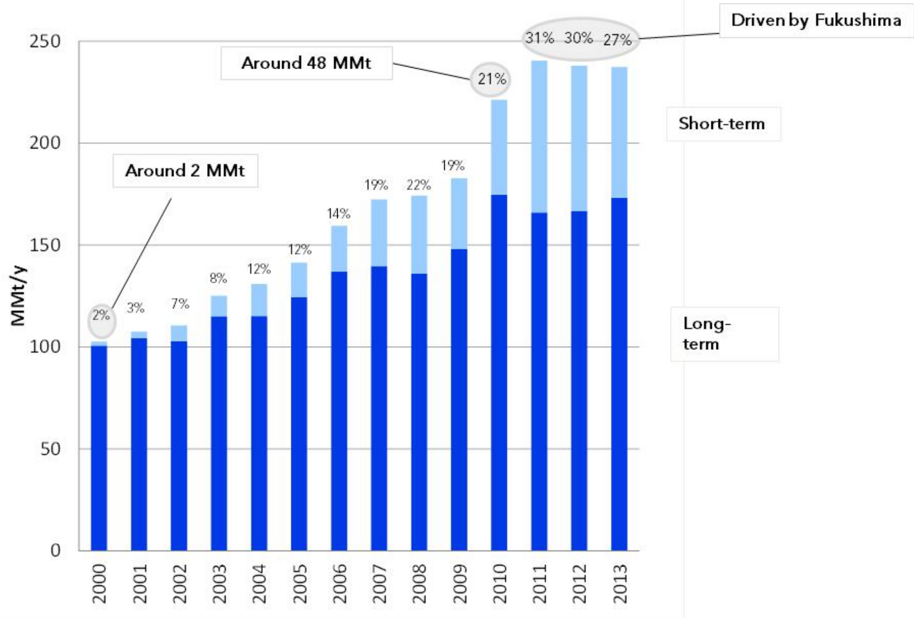
Year Signed	Supply Project	Seller	Seller Country	Buyer	Buyer Country	Volume (MMt/y)	FOB / DES	Start Year	Base Term (years)	Reference Crude Oil / Hub Gas	% crude/hub price	Fixed Element ($/MMBtu)	S-Curve: Yes/No?
2012	Sabine Pass	Cheniere	USA	BG	Portfolio	2.00	FOB	2015	20	HH	1.15	3.00	No
2012	N/A	BP	Portfolio	IEC	Israel	0.63	DES	2013	1	NBP	1	7.00	No
2012	N/A	Eni	Portfolio	Enarsa	Argentina	0.67	DES	2013	1	HH	1	12.00	No
2012	N/A	BP	Portfolio	Enarsa	Argentina	0.24	DES	2013	1	HH	1	13.50	No
2012	N/A	Gas Natural	Portfolio	Enarsa	Argentina	1.40	DES	2013	1	HH	1	12.00	No
2012	N/A	Vitol	Portfolio	Enarsa	Argentina	0.70	DES	2013	1	HH	1	13.50	No
2013	N/A	BP	Portfolio	Enarsa	Argentina	0.1	DES	2013	1	HH	1	13.50	No
2013	N/A	Shell	Portfolio	Enarsa	Argentina	0.13	DES	2013	1	HH	1	13.50	No
2013	N/A	Petronas	Portfolio	Enarsa	Argentina	0.1	DES	2013	1	HH	1	13.50	No
2013	N/A	BP	Portfolio	Enarsa	Argentina	0.13	DES	2013	1	HH	1	12.50	No
2013	N/A	BP	Portfolio	Enarsa	Argentina	1.23	DES	2014	2	HH	1	11.00	No
2013	N/A	Gazprom	Portfolio	Enarsa	Argentina	0.46	DES	2014	2	HH	1	11.50	No
2013	N/A	Gas Natural	Portfolio	Enarsa	Argentina	1.40	DES	2014	2	Brent	0.135	-	No
2013	Yamal LNG	Yamal LNG	Russia	Gas Natural	Spain	2.50	DES	2019	20	60% Brent / 40% NBP	0.12 Brent / 0.975 NBP	-	No
2014	N/A	Statoil	Portfolio	Litgas	Lithuania	0.40	DES	2015	4	NBP	1	2.00	No
2015	N/A	Vitol/ Noble Gp./ Trafigura/ BP	Portfolio	EGAS	Egypt	4.40	DES	2015	2	Brent	0.14	-	No

H.3.5 LNG Spot Market

Natural gas and LNG projects are highly capital-intensive. One result of this is the predominance of long-term offtake contracts, typically with a 20 or 25 year duration. These contracts underpin the project financing required. However, increasing quantities of LNG are being made available to the spot and short-term markets through divertible cargoes, cargoes sold FOB and the marketing of spare capacities at the liquefaction terminals. Poten estimates that around 66 MMt was traded spot/short term in 2013, as shown in the figure overleaf (42 MMt into the Pacific Basin, 22 MMt into the Atlantic Basin and 2 MMt into the Middle East).

[3] Information contained in the table above is based on market intelligence and is provided without warranties of any kind, whether expressed or implied. Information is not to be re-produced without consent of Poten & Partners. Copyright 2015.

Figure H-43 Development of LNG Spot/Short-Term Trade



A sharp growth in LNG demand in SE Asia, mainly in Japan following Fukushima, and in niche markets has driven the recent increase in spot and short-term LNG volumes being made available from existing projects (e.g. from Nigeria LNG, ramp up of new supply projects, and a significant increase in the percentage of flexible Qatari volumes sold as spot) and diversions from Atlantic Basin markets due to a reduction in demand and the resultant low gas prices. In many instances these volumes are part of the portfolio held by larger, more established buyers (also known as "aggregators"), but procured under long-term contracts with export projects.

H.3.5.1 Spot Market Realities

There are a number of factors that limit the availability of LNG for trading within the spot market and will also limit the ability of a player to participate/trade within the spot LNG market. These include:

- Spot cargoes – that is, those turned away or diverted from their originally nominated destination at short notice – have traditionally accounted for a very small proportion of the total volumes in the LNG market. In 2000, only 2% of total volumes could be classified as spot or short-term. While true spot volumes have grown significantly both in absolute terms and as a percentage of total volumes, spot and short term trade is still a minority (27%) of the total LNG market.
- High costs associated with building LNG production plants put an effective ceiling on the amount of LNG made available to the market as spot cargoes. Capital intensive projects need to secure long-term contracts prior to FID being made.
- Over-production at plants does create some extra volume, but usually this is first offered to the existing off-takers rather than to the open market. In recent times, some markets in Europe have offered "reloaded" cargoes – that is, volumes that have been delivered but which have not left the tank and are then reloaded for export on another ship.

However, the situation has been improving and this is mainly due to a greater degree of flexibility within the SPA terms afforded to a buyer of LNG in the diversion of cargoes and also the long term commitment to LNG tolling arrangements. Access to more liquid downstream natural gas markets and the ability for a Seller to buy backfill volumes in order to make up for the volumes that would have otherwise been delivered into the downstream market will also play a role in improving the availability of LNG on the spot market, making the more liquid tradable gas markets of North West Europe, such as UK and Netherlands, potentially attractive markets to divert to and away from.

Access to shipping is extremely important in the short term purchase of LNG. Most LNG vessels were built to serve a specific project and continue to serve fixed routes. However, the growing number of owners and projects, and the rate at which vessels have been being built during recent years, means that the global LNG fleet is increasing. This in turn is opening up the market for some of the smaller, less well-established, players to participate and not only those large companies with their own sizable fleets. This offers greater opportunities for the type of short-term chartering, with ships being built on a more "speculative" basis. The availability of short term charters is often what is required for parties wishing to take part in the spot or short term LNG market.

H.3.5.2 Spot Market Pricing Trends

Spot Market Pricing

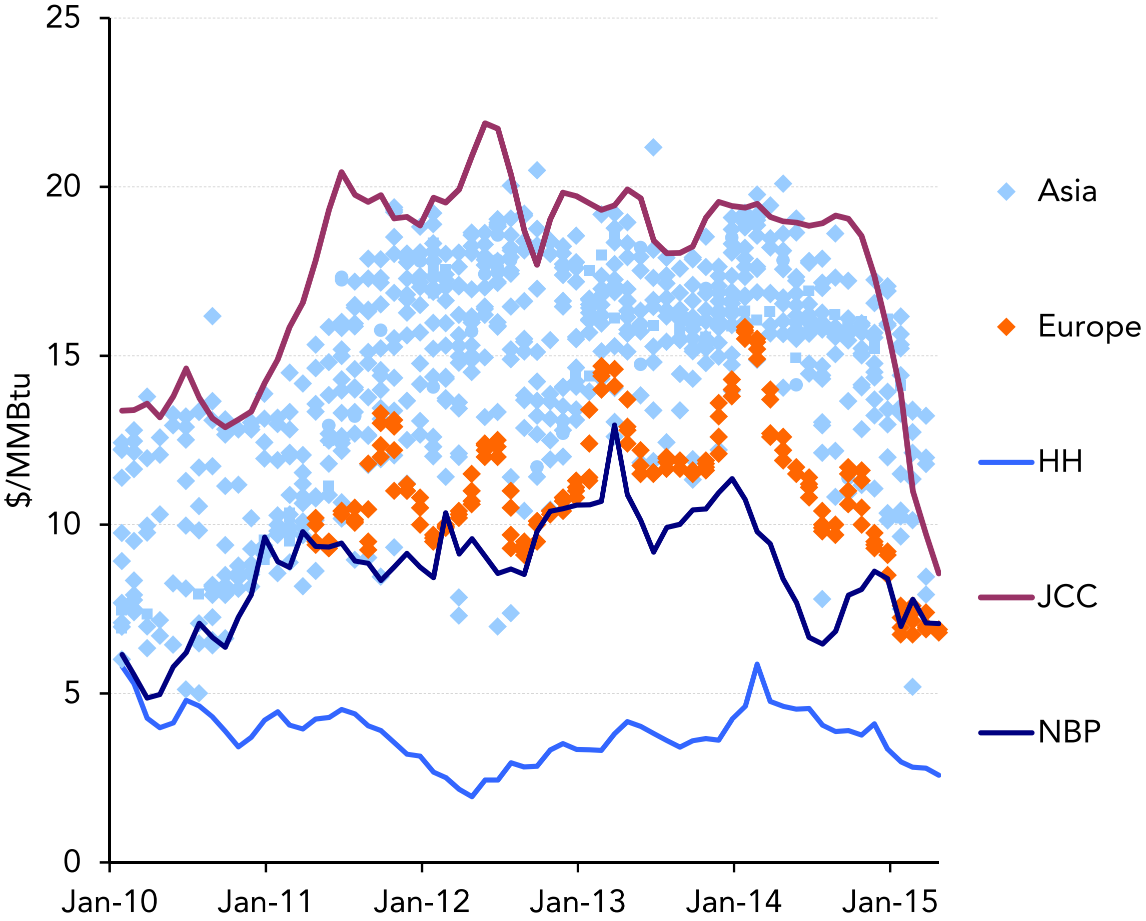
Whereas long-term contract pricing formulae which has so far been usually a percentage of crude oil price, e.g. Brent, with the addition a fixed component to cover the cost of production, liquefaction, etc., spot volumes are usually priced on a 'US$/MMBtu' basis, which is usually driven by the price achievable at a regional hub, such as HH or NBP and the ability of the seller to "backfill", i.e. buy gas back at the hub to replace the gas that might be otherwise delivered to the market as a cargo of LNG. Spot volumes offered to the market are priced according to the market conditions at the time and what the alternative might be for the seller.

Asia Sets the Price

Much of the increase in the "trading" of LNG on a spot basis has been driven by the increased demand for LNG in Japan (after Fukushima) and Korea (due to an increase in demand for power). A lack of availability of long term supplies of LNG means that countries such as Japan and Korea have become reliant upon the availability of LNG within the short term, spot, market. As a result, Asian buyers have tended to buy LNG supply at the higher price reflective of the contract price being paid by those buying LNG on a long term basis under oil indexed (referred to as JCC) SPAs In the US and Europe buyers will tend to be looking to pay prices based on the more liquid natural gas hubs, for example, UK's NBP.

However, the ability for buyers in Europe to buy spot LNG at the lower "gas-indexed" price will be very much dependent upon the ability of the seller to divert a cargo to the more lucrative Asian market, or not.

Figure H-44 Spot/Short-Term LNG Prices



Over the last two years, with the rise of gas demand in South America, Brazil and Argentina have entered the fray and have had to compete on an equal footing with the Asian buyers for a limited availability of LNG on a short-term basis. Players from these countries have on occasions been forced to pay a premium to the price bid by the traditional Asian buyers in order to secure the cargoes.

Cross-Basin Diversion

Recent demand across regions has been strong enough to attract cargoes from afar. As a rule of thumb, if Asian demand is strong enough to justify offering a premium or “spread” of US$4/MMBtu or more over European prices, this is considered to be sufficient to bring Atlantic Basin cargoes over to the Pacific Basin. Since the Fukushima disaster in Japan, and to the need for Korea to produce more electricity, this has happened more often, with raised demand in Asia and as a result an increased spot price. There have also been a few cargoes that have even gone in the opposite direction, from the Pacific Basin to the Atlantic Basin, for South American buyers, such as Brazil and Argentina, willing to offer a premium above the Asian price sufficient to cover any additional shipping costs.

It is important to note that while Asian buyer will tend to be setting the higher price at which LNG might trade within what might be considered to be a “seller’s” market, the demand for short-term LNG in Asia will determine whether it is the towards the higher priced Asian market that a cargo is headed or the lower priced markets such as Europe. More recently a change in the demand for LNG in Asia, along with a reduced oil price, has seen the spread achievable by those looking to divert their cargoes away from the

Atlantic Basin and towards the Asia-Pacific Basin fall below the threshold of US$4/MMBtu generally considered to be required in order to cover the additional costs of shipping. This has resulted in more cargoes being destined for the European market which is fast being considered as being the location of last resort for such cargoes.

Volatility of Spot Prices

By their very nature, spot LNG prices are considered to be volatile. This depends entirely on the available of supply elsewhere and the demand for LNG at the time. Global trends will have an effect on the market, as has been seen during recent months with reduced oil price, as do local factors such as the mild winter that was experienced in Korea and the subsequent downturn in demand for spot LNG. Shipping availability is also a key factor in formulating spot prices. Some broad trends are obvious: spot prices tend to be higher in premium markets such as Far East Asia and during the winter within the northern hemisphere.

H.3.5.3 Reloads/Re-exports

Reloading, also known as "re-exporting", has been around since 2004, but at first was mainly used as a means of sorting out internal balances or specific problems in relation to the terminals. Re-exporting on a commercial scale started four years later, in 2008, after Belgium's Zeebrugge terminal offered a reloading service to third parties. This was used by Distrigas (Eni) when volumes originally delivered to Zeebrugge by Qatar, to be sold into the Belgian market by Distrigas, were instead reloaded by Distrigas and delivered into the Spanish market via the Bilbao terminal. The vast majority of reloads now, however, end up leaving Europe and reloading of cargoes has been used as a means of overcoming any contractual restrictions that might still exist in diverting cargoes, i.e. in relation to location specific SPAs, in order to deliver LNG into more lucrative markets.

Such reloading is obviously unpopular with sellers, particularly those in Yemen, Qatar and Nigeria who are also unable to divert their cargoes and are obliged to deliver these volumes into European terminals as part of a long-term, location-specific SPA at prices that may be considered to be non-optimal when compared to prices elsewhere. Unless the terms say otherwise, they can only watch as their Buyers reload them and ship them as Sellers, so adding to the competition in these higher priced markets.

H.4 PETROCHEMICAL MARKETS

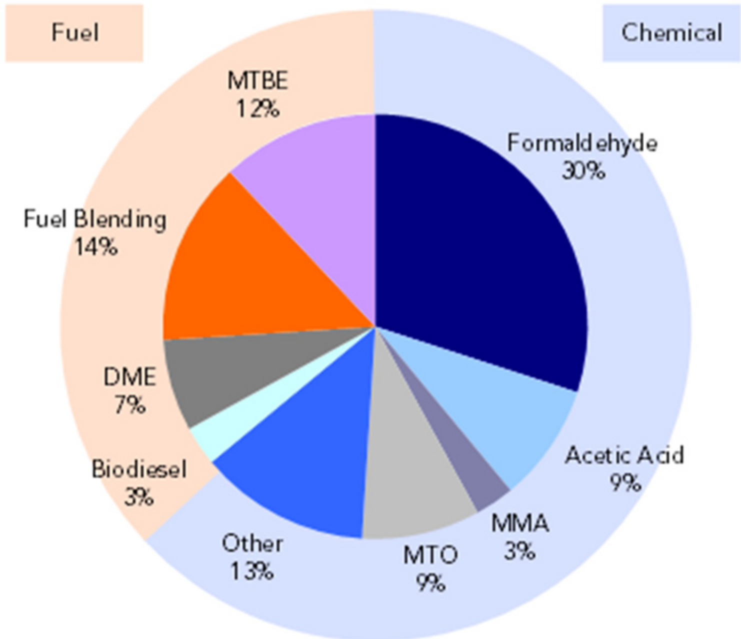
H.4.1 Methanol

Methanol is an important global commodity chemical. It is the simplest alcohol with chemical formula CH_3OH. Outside of China, which has a very large and growing production capacity based on coal, methanol production is mainly from natural gas feedstock. Historically, gas-based capacity has been focused on low-cost regions such as the Middle East, but the advent of the shale gas revolution in North America will see a large increase in methanol production capacity in the US, including relocation of two plants from Chile to Louisiana.

The major uses for methanol are as a chemical intermediary in the production of wide variety of downstream derivative products, and the use of methanol or methanol derivatives as a fuel.

Figure H-45 Methanol Demand by Derivative/Sector 2014

(excluding CTO/CTP)



H.4.1.1 Chemical and Industrial Uses of Methanol

Chemical uses for methanol account for around 60% of demand. Traditional chemical derivatives include formaldehyde, acetic acid and methyl methacrylate (MMA), while methanol-to-olefin (MTO) technologies including methanol-to-propylene (MTP) have recently been commercialized.

Traditional Chemical Uses (Formaldehyde, Acetic Acid, MMA)

The largest of the traditional chemical uses for methanol is in the production formaldehyde which is predominantly used in the production of glues and resins (urea formaldehyde, melamine formaldehyde and phenol formaldehyde) for plywood and chipboard/particle board production. These products are generally used in construction and furniture manufacture. Among many other smaller uses, formaldehyde uses also include polyacetals (polyoxymethylene or POM), used in engineering plastics and 1,4-

butanediol, which is used as a solvent and in the production of polybutyl terephthalate (PBT), a high-performance plastic.

The second largest chemical consumption of methanol is in the manufacture of acetic acid which accounts for around 10% of methanol demand globally. Acetic acid is used in the production of vinyl acetate, cellulose acetate and acetate esters for use in paints, adhesives and textiles. Acetic acid is also used in the production of purified terephthalic acid (PTA), a raw material used in making polyethylene terephhalate (PET) and also, a raw material for PBT production.

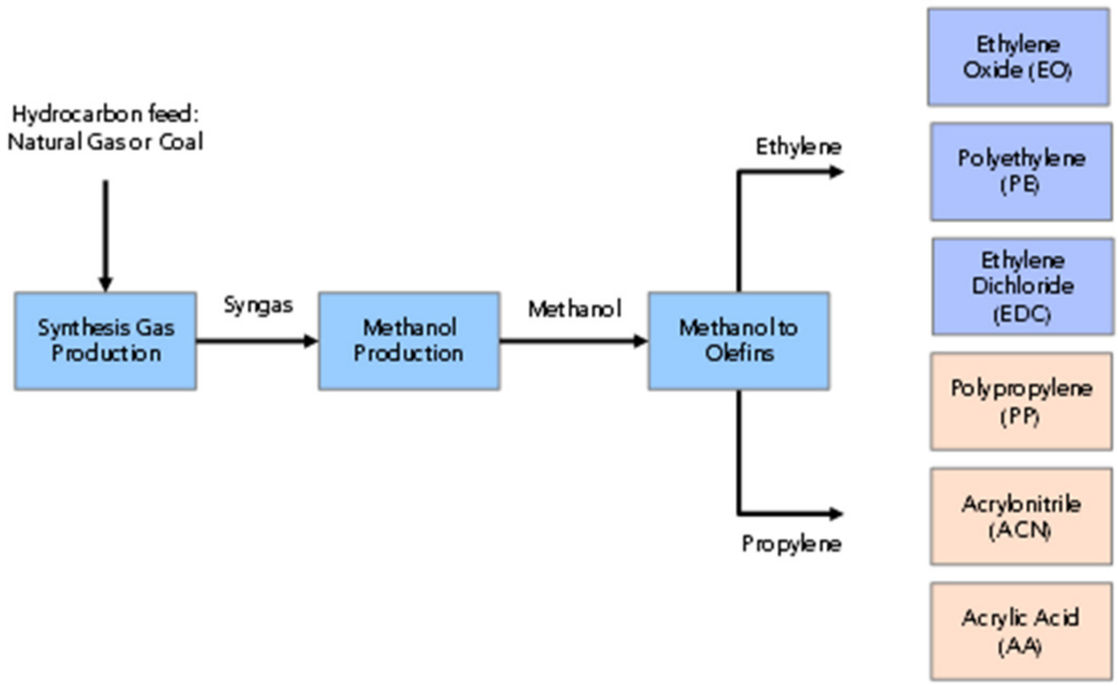
Other traditional chemical uses for methanol include methyl methacrylate (MMA) which is used in the production of acrylic sheet, surface coatings and moulding resins; and dimethyl terephthalate (DMT) which is used in polyester fibre, film and bottle resins. There are many other smaller uses of methanol, which together account for around 13% of methanol demand. Overall demand for these traditional chemical derivatives for methanol is expected to grow related to GDP growth rates.

Methanol to Olefins (MTO)

Methanol to Olefins (MTO) is a relatively newly commercialized technology for converting methanol to light olefins (ethylene and propylene).

Figure H-46 Schematic for Methanol to Olefins

(incl. Major Ethylene and Propylene Derivatives)



China is leading the commercialization of MTO, where olefin production from methanol has grown strongly since the first MTO plant started up in 2010. At end-2014, there were six plants operating in China with the capacity to consume over 6 MMt/y of merchant methanol (where methanol is purchased from the market) and are important methanol buyers. The remaining plants are based on large-scale coal to olefin (CTO) technology where the methanol is produced from coal and directly consumed on site. Although these plants do not generally impact the merchant methanol market as they are integrated coal-to-methanol-to-olefins projects, they can also source merchant methanol to supplement their own production. Poten's methanol supply and demand figures do not include methanol consumed in these integrated CTO plants.

The increase in the use of methanol to produce olefins is driven through by the traditional production of olefins from naphtha and several other integrated and non-integrated projects are currently under construction in China.

H.4.1.2 Fuel Use of Methanol and Methanol Derivatives

Methanol finds its way into the gasoline pool through direct blending of methanol into gasoline and use of the high-octane blending component MTBE as an oxygenate for gasoline. It is also used in the production of biodiesel. Other applications for methanol in fuel use include its derivative dimethyl ether (DME) which can be blended with liquefied petroleum gas (LPG) as an alternative domestic heating fuel, or used directly as a diesel fuel replacement. Future uses of methanol which are being developed include its use as a low Sulphur marine fuel.

While the traditional chemical uses for methanol are mainly in mature industry sectors, with demand related to GDP growth, the methanol-to-fuel sectors have grown very rapidly, driven by gasoline blending in China.

MTBE (methyl tert-butyl ether)

Production of MTBE accounts for around 12% of methanol production. It developed as a replacement for tetra-ethyl lead (TEL) as an octane-enhancing component of unleaded gasoline where it also benefits from being an oxygenate, aiding clean combustion in the engine. Although MTBE has been banned in the US, due to contamination of ground water through leakage from underground storage tanks (MTBE is water soluble and gives an unpleasant taste even at extremely low concentrations), it is still in global use. In the US, its use has been replaced by other oxygenates such as ethanol. Globally, methanol demand into MTBE is growing at around 4% p.a. driven by increasing use in Asia.

Dimethyl Ether

Dimethyl ether (DME) is a clean-burning fuel which can be blended with LPG as an alternative domestic heating fuel, or used directly as a diesel fuel replacement. Its use has grown significantly, with methanol demand into DME estimated at around 5-6 MMt in 2014, chiefly in China where it is also an intermediary in MTO and MTP processes.

Gasoline Blending and Biodiesel

Methanol can be used directly as a fuel in gasoline; it is a clean-burning oxygenate fuel which can be blended directly into gasoline, or used as a fuel additive to reduce emissions. It benefits from being in liquid state under normal conditions and offers transportation advantages versus gas and LNG, although it has a relatively low energy density in comparison to liquid hydrocarbons.

There are no technical hurdles in the delivery infrastructure for methanol blended gasoline and no need for specialised vehicles for significant methanol penetration. Gasoline with methanol content of up to 30% (M30) is generally interchangeable with normal gasoline and is compatible with existing gasoline engines without engine modification. Gasoline with even higher amounts of methanol, such as M85 (85% methanol) M100 (100% methanol) can be used in specialised or modified vehicles. Direct blending of methanol into gasoline has grown strongly in China, and is supported by provincial fuel blend standards. As well as burning cleanly, a further key factor driving the strong growth of methanol as a transportation fuel, is methanol's cheaper cost relative to gasoline.

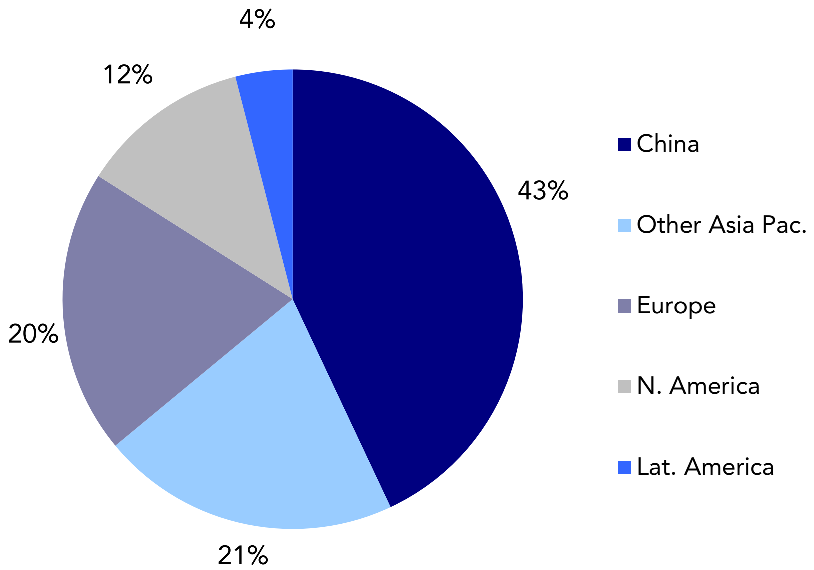
Methanol is also a key component in the production of renewable biodiesel fuels, where methanol is mixed with biological products such as corn and vegetable oils. Methanol is also beginning to show promise as a marine fuel, but this application is still at a very early stage of commercial development.

H.4.1.3 Global Methanol Market

Global demand for methanol (excluding methanol demand in vertically-integrated Chinese CTO plants) is estimated at around 67 MMt/y in 2014. Including methanol consumed in CTO, the total methanol market is estimated at 72 MMt/y. China dominates the global methanol market, with around 50% of installed capacity and 43% of global demand. Iran, T&T and Saudi Arabia are the largest global net exporters of methanol, each exporting volumes around the 4 – 5 MMt/y range. These positions have been developed on the basis of very low cost feedstock gas (less than US$1/MMBtu in the cases of Iran and Saudi Arabia). However, low prices in the Middle East have led to booming domestic demand for gas and have resulted in gas shortages, such that we would expect gas prices to be substantially higher for future projects.

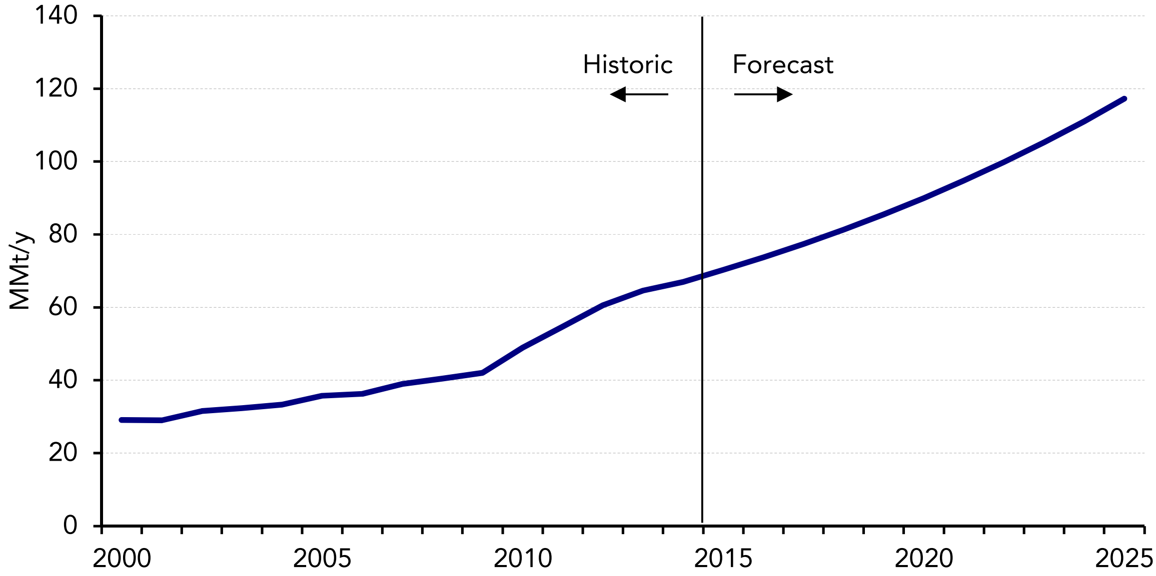
Figure H-47 Global Methanol Demand by Region in 2014

(source: Methanex)



Chinese demand is driving the global methanol market. Demand in China is growing at around 12% p.a. while the rest of the world has seen growth rates just over 3% p.a. Methanol to olefins and gasoline blending are leading the growth in the Chinese market. Global methanol demand is expected to reach 117 MMt/y by 2025.

Figure H-48 Historical & Projected Global Methanol Demand



H.4.1.4 Methanol Supply

Methanol is produced from syngas (a mixture of hydrogen and carbon monoxide), which can be produced from a wide array of feedstocks (coal, natural gas, naphtha, fuel oil, coke, etc.). The most prevalent feedstock is natural gas, which accounts for around 70% of production, due to the cost advantages of natural gas feedstock. The two largest players in the market (Methanex and SCC/Helm) have a combined market share of around 25% of the global merchant market.

Chinese Supply

China is the largest producer of methanol globally, accounting for nearly 50% of all installed capacity worldwide. Ownership of China's methanol production is highly fragmented, with many hundreds of small producers as well as very large coal-to-methanol and integrated coal-to-olefin producers. Chinese methanol production is centred on the remote and abundant coal resources in northern China (Inner Mongolia, Shanxi and Shaanxi provinces) and western China (Xinjiang and Ningxia provinces).

North American Supply

The rise of North American shale gas has already resulted in the restart of existing plants and the construction and start-up of new plants in North America. As well as several smaller expansion projects and debottleneckings, the past three years has seen the restart of three plants (Methanex's 470 kt unit at Medicine Hat, Alberta; OCI's 750 kt Pandora facility at Beaumont, TX; and Lyondell's 740 kt at Channelview, TX) and the relocation and start up of the first 1000 kt (1.0 MMt/y) Methanex facility from Chile to Geismar, LA. We expect to see a continued large build up of methanol capacity in North America, driven by abundant, cheap shale gas.

Table H-11 North America Planned Methanol Capacity Additions

(source: company data)

Company	Location		Project Type	Capacity kt	Start	Status
Celanese	Clear Lake	Texas	New	1,300	Q4 2015	Construction
Methanex	Geismar	Louisiana	Relocation	1,000	Q1 2016	Construction
OCI N.V.	Beaumont	Texas	New	1,800	Q1 2017	Construction
South LA Methanol	St James Parish	Louisiana	New	1,800	2018	Planning
Valero	St Charles	Louisiana	New	1,800	2018	Planning
Big Lake Fuels (G2X/MHTL)	Lake Charles	Louisiana	New	1,400	2018	Planning
Fund Connell	TBD	TX/LA	New	3,600		Proposed
Methanex	Medicine Hat	Alberta	Expansion	1,000		Proposed
LCCE	Lake Charles	Louisiana	New	1,000		Shelved

Over 4 MMt/y of capacity is under construction in the US including two new plants and a relocation from Chile (1.3 MMt/y Celanese plant is under construction in Clear Lake, Texas; OCI N.V. has commenced construction of a 1.8 MMt/y plant in Beaumont, Texas; 1.0 MMt/y Methanex plant is being relocated from Chile to Geismar, Louisiana). In addition, more than 9 MMt/y of methanol capacity is in advanced planning or has been proposed in North America as shown in the table above. These plants see their markets as supply targeting the North American fuel-blending market and secondarily the Chinese export market.

Several more methanol export-oriented projects have been announced where much of the proposed capacity is earmarked for export, including Chinese-sponsored projects. At least one plant is proposed for the US Gulf Coast (Yuahuang Chemical) and plans for three plants have been announced for the Pacific North West Coast (Northwest Innovation Works – 3 x 1.6 MMt/y plants).

H.4.1.5 Methanol Trade

The USA and China are the key global methanol importers. Net imports into both the USA and China were of the order of 5 MMt in 2013/14. Other major import markets are Japan, South Korea and the EU.

Table H-12 2014 Methanol Trade Patterns
(source: Eurostat, USITC,UN)

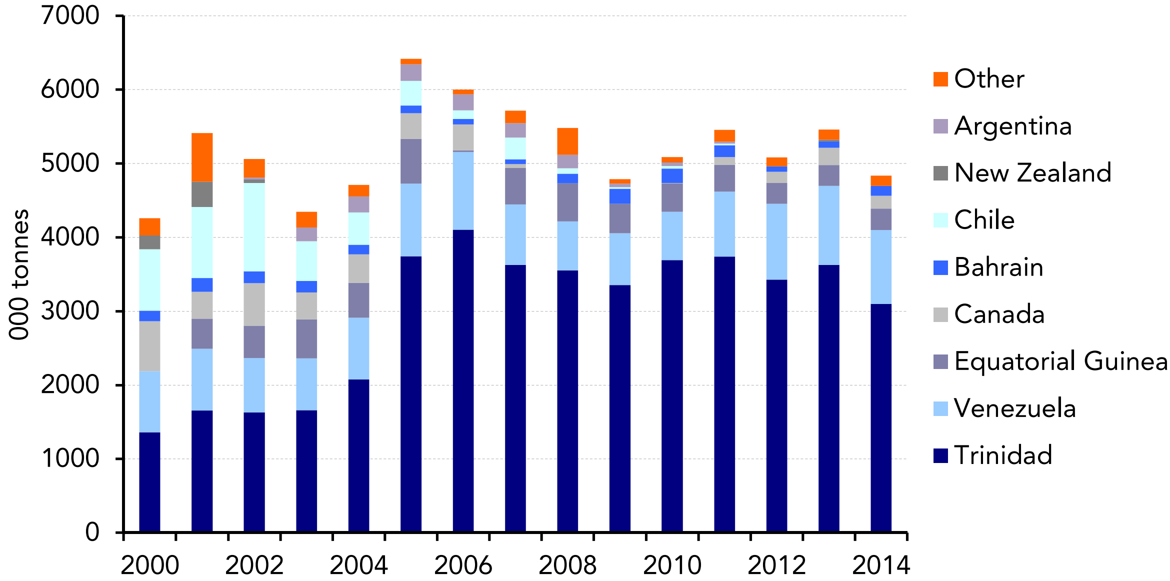
Country	Imports 2014 MMt	Main sources (Volume MMt)
EU 28	9.3	Intra-EU (2.6) Russia (1.1) Norway (0.4) Saudi (0.7) Eq. Guinea (0.7) T&T (0.5) Libya (0.2) Venezuela (0.1)
China (2013 figures)	5.0	Iran (2.0) Oman (0.8) Saudi (0.6)
US	4.8	T&T (3.1) Venezuela (1.0) Eq. Guinea (0.3) Canada (0.2) Bahrain (0.1)
Japan	1.7	Saudi (1.0) New Zealand (0.3) Malaysia (0.1)
Korea	1.5	New Zealand (0.8) Oman (0.2) Saudi (0.2)

US Imports

According to US International Trade Commission (USITC), the US imported 6.1 Bn litres of methanol (4.8 MMt) of methanol for domestic consumption in 2014, 64% of which (3.1 MMt) originated from T&T.

The build-up of US methanol capacity will reduce the US import need for methanol, and the US is expected to become a net-exporter of methanol around 2017/18. In addition to loss of North American markets, having lost the 5MMt/y US import market, T&T methanol producers will have to compete against North American exports into other global markets including the regional South American market, Europe and Asia (China).

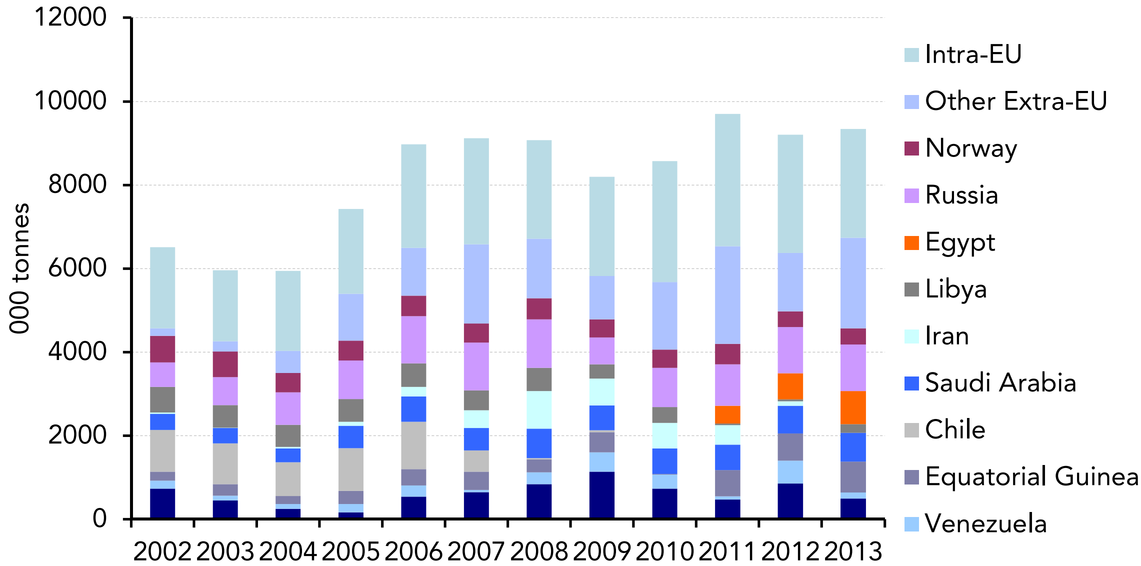
Figure H-49 US Methanol Imports
(source: USITC)



European Methanol Imports

According to Eurostat data, EU 28 countries imported 9.3 MMt of methanol in 2013. While a significant volume is traded within the borders of the EU (exports from the Netherlands), Europe imported 6.7 MMt from extra-EU sources.

Figure H-50 EU 28 Methanol Imports
(source: Eurostat)



The largest single source of European imports is Russia (1.1 MMt in 2013), followed by Egypt (0.8 MMt), Equatorial Guinea and Saudi Arabia (both at 0.7 MMt). T&T is also a major source of European methanol imports, with EU28 declared imports standing at 496 kt in 2013, down from 857 kt in 2012.

H.4.1.6 Methanol Pricing

Historical Methanol Pricing

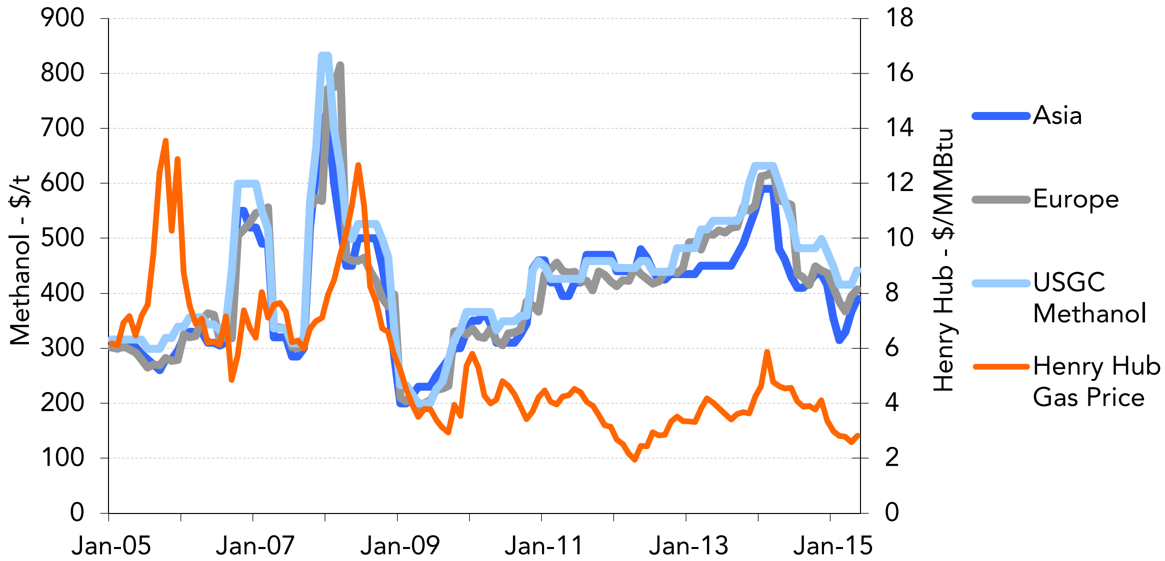
As with other commodity chemicals, methanol prices respond to market forces. However, two key underlying factors are seen as the major drivers for methanol pricing:

- Production costs, which are in turn mainly driven by feedstock prices. The cash cost of production (from low cost natural gas or coal in China) sets a floor.
- Margin over costs which is driven by supply and demand fundamentals. Prices can be well above costs if demand is high.

Prior to 2006, US methanol production costs, which are a function of US gas prices, were a significant influence on global pricing as the US was the marginal source of production. Since then the influence of the US waned and methanol prices decoupled from US natural gas as a large proportion of US methanol production closed due to rising costs, reducing its market impact. US gas prices have subsequently been depressed by the advent of shale gas while methanol prices as shown in the figure below have risen strongly since mid-2009 as demand has grown.

Figure H-51 Methanol and Henry Hub Prices

(Posted Contract price US$/tonne v Henry Hub spot US$/MMBtu. source: Bloomberg, Methanex)



Methanol Price Forecast

Methanol prices have historically been very volatile, and are sensitive to global supply and demand dynamics. However, the economics for fastest growing methanol uses and derivatives (gasoline blending, MTO and DME) are based on substitution of or competition with oil products, particularly in the Chinese market (methanol gasoline blending and MTO.

Figure H-52 Methanol and Crude Oil Prices

(Posted Contract price v Brent spot. source: Bloomberg, Methanex)

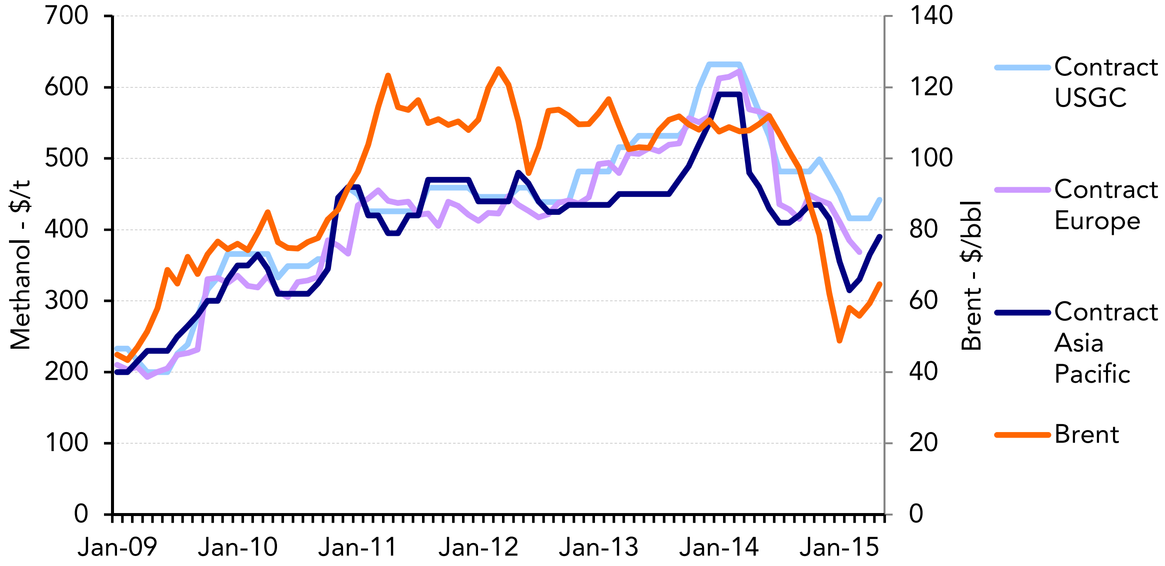
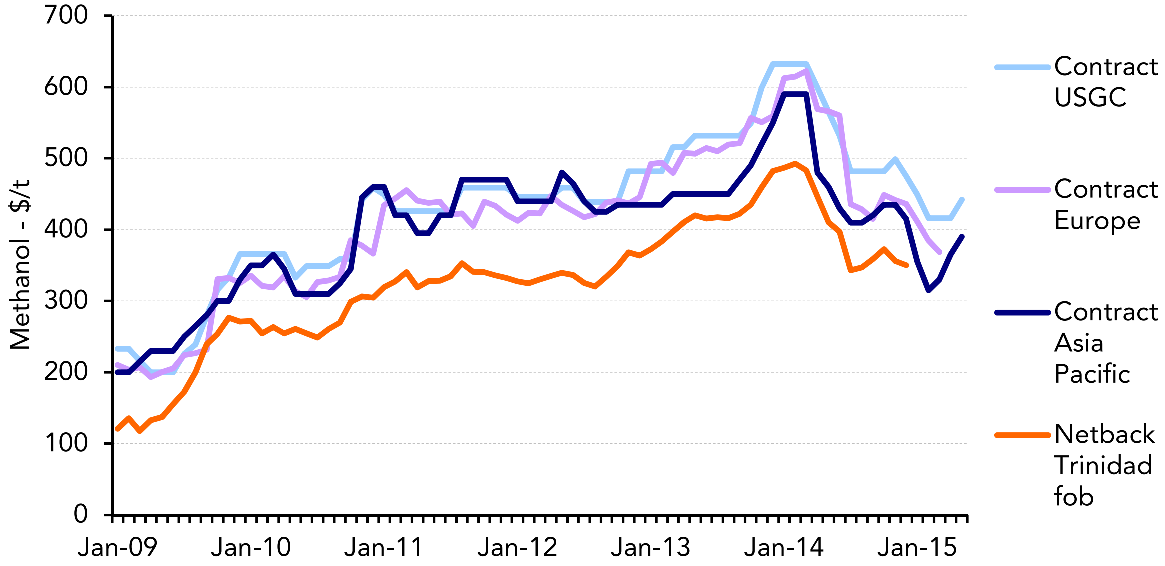


Figure H-53 Realised Methanol Prices

(fob T&T v Posted Contract prices, source: Methanex, MEAA)



This has had the effect that methanol prices have increasingly tended to correlate with crude oil prices. We expect that methanol prices will continue to be correlated with oil prices, with supply and demand factors playing a less significant factor.

H.4.2 Ammonia

Ammonia is a major globally-traded chemical intermediate. Its main use is in the manufacture of nitrogen fertilisers, which account for over 80% of ammonia use. Fertiliser demand is driven by population growth and economic growth. Population demand increases food consumption of fruit and vegetables in developing countries, while economic growth also increases protein (meat) uptake, which results in higher grain consumption as animal feed. These combined effects boost fertiliser use in agricultural production, with increased demand for food being met by higher fertiliser application rates per hectare to boost production. Biofuels such as ethanol derived from corn and vegetable oils for biodiesel are also gaining importance and contribute to increasing demand for fertilisers.

Ammonia and its derivatives are also used in the manufacture of a wide variety of chemical products and industrial applications including plastics, fibres, explosives, nitric acid and intermediates for dyes and pharmaceuticals.

Anhydrous ammonia is a colourless, pungent-smelling gas at room temperature and atmospheric pressure. Large quantities are usually stored in cryogenic facilities as a liquid with bulk storage usually operated at a temperature of around -33.3^{o}C at ambient pressure in single or double-walled tanks. Its volatile and dangerous nature requires special care in its handling and storage, but this is not unduly difficult. Anhydrous ammonia is similar to LPG in some respects and is usually transported a refrigerated/cryogenic or compressed liquid. It is readily soluble in water and can be also be used/transported as an aqueous ammonia solution.

Ammonia is produced from natural gas via a syngas process. The main feedstock globally is natural gas, but it is also produced from liquid or solid fuel, for example in China where there is very large and growing ammonia production based on coal, while in India, naphtha is widely used.

H.4.2.1 Uses of Ammonia - Fertiliser

The main use of ammonia is in the production of nitrogenous fertilisers. Ammonia (82% N), is the main source for nitrogen in various types of fertilisers used in crop production. The most important of these is urea (as discussed later in this Appendix). Anhydrous ammonia can be applied directly to soil in its pure form, although it is mainly used in the production of other solid or liquid fertilisers such as ammonium nitrate (AN), ammonium phosphates - diammonium phosphate (DAP) and monoammonium phosphate (MAP), urea ammonium nitrate solution (UAN) and ammonium sulphate. Other fertilizers, including the direct application of ammonia, accounted for a further 34% of total consumption.

H.4.3 Urea

Urea is used in many areas of the world as the primary source of nitrogen for crop nutrition because of its high nitrogen content (46% N). It is used extensively in developing regions of the world and traded widely on international markets. Around half of the global production of ammonia is consumed for urea production for fertilizer.

Urea, chemical formula $CO(NH_2)_2$ is a solid, produced from the reaction of ammonia with carbon dioxide (CO2). It is usually produced adjacent to/integrated with ammonia production as ammonia production produce carbon dioxide as a by-product. Many facilities can switch between the production of ammonia and urea depending on prevailing global prices.

Urea can be used alone for fertiliser use, or combined with other phosphate and potash fertilisers in NPK blends. It is also a constituent of UAN along with ammonium nitrate, which T&T exports in solution form.

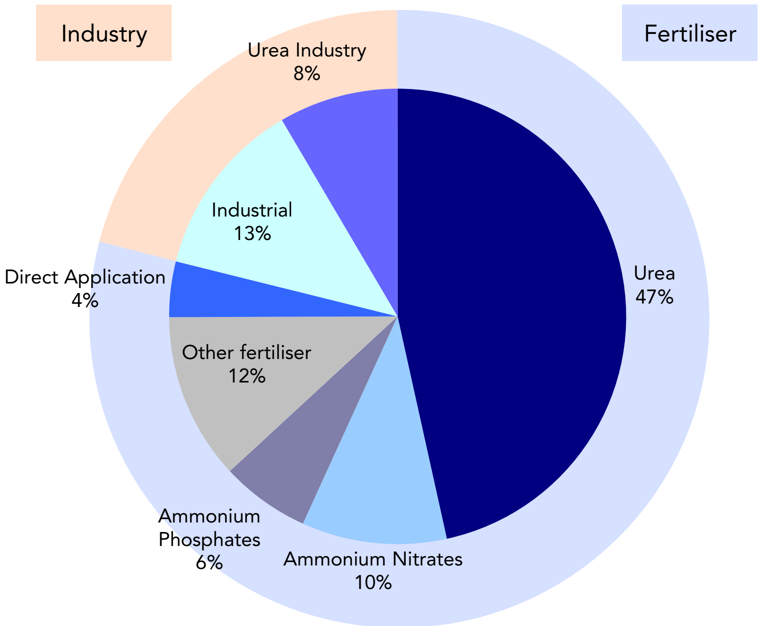
There are several chemical and industrial uses for urea. The main uses are in urea-formaldehyde resins and melamine which are used in furniture and building applications. An outlet for urea which is enjoying strong growth rates in Western Europe in particular is its use as a selective catalytic reduction (SCR) in diesel engines, where a urea solution (for example AdBlue) is injected into the engine exhaust system to reduce emissions.

Including the urea share from industrial consumption, urea consumes around 55% of all ammonia production. China (estimated 62 MMt) and India (23 MMt) are by far the world's largest producers and consumers of urea. Urea production reached 169.3 MMt in 2013, up 4.6% from 161.8 MMt in 2012.

H.4.3.1 Chemical and Industrial Uses of Ammonia

Ammonia is also consumed in numerous chemical and industrial applications such as production of acrylonitrile, caprolactam, aniline (through nitric acid and nitrobenzene) and nitrate based explosives, and in aqueous solution as a solvent. It is also used as a refrigerant. Around 13% of ammonia is consumed in these chemical and industrial applications. The estimated breakdown between fertiliser use and non-fertiliser use by derivative is shown in the figure below.

Figure H-54 Ammonia Demand by Derivative/Sector 2014

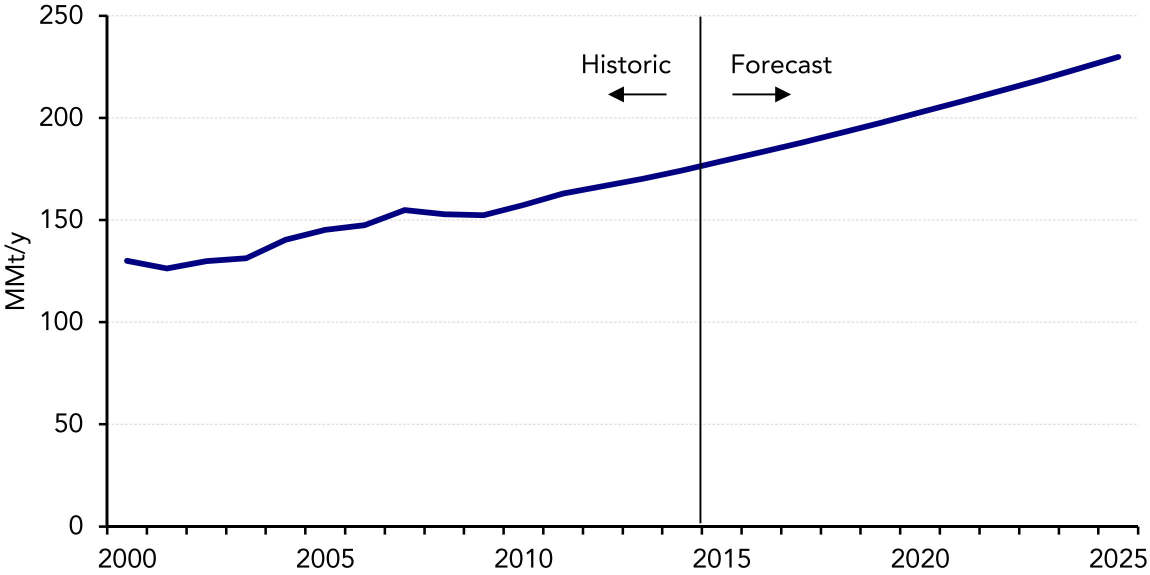


H.4.3.2 Global Ammonia Market

The global ammonia market is estimated at around 170 MMt in 2013. Global nitrogen-fertiliser demand is expected to continue to grow at around 2.3% p.a. or around 3 MMt/y of nitrogen (6 MMt/y of urea product). This equates to around 4-5 new world scale urea plants each year. Industrial use is projected to grow at a higher rate (3.7% p.a.), largely due to increasing demand for urea in emissions control applications.

Demand growth is expected to be strongest in developing regions, particularly Asia, and Latin America. Growth is expected to be more muted in North America. Global ammonia demand is projected to reach around 230 MMt/y by 2025.

Figure H-55 Historical & Projected Global Ammonia Demand



H.4.3.3 Ammonia Supply

We estimate global ammonia production at around 170 MMt in 2013, up from 166.6 MMt in 2012. The trend over the last decade has been upwards, with global average growth 2003-2013 at 2.6% p.a. Global ammonia production is dominated by China, which produces around one-third of global output (approx. 55 Mt/y). China is followed by Russia (14 MMt/y) and India (13 MMt/y) and then the US, with production of around 10 MMt/y in 2013. Global ammonia capacity is projected to grow around 4% to 224 Mt in 2015. New capacity is expected to come onstream in Brazil, China, Egypt, India, Indonesia, Russia and Vietnam.

North America Ammonia Supply

Between 2000 and 2006, much of the ammonia capacity in the US was closed due to high costs. From 2000 to 2006, the annual capacity declined from 20 MMt/y to 13 MMt/y. Over the same period, annual U.S. ammonia production fell from 18 MMt/y to 10 MMt/y, some 44%. Ammonia and nitrogen fertiliser demand was still strong, and the increased need for US imports of ammonia created the opening for exports from T&T with to exploit its low cost gas.

As natural gas feedstock costs account for over 50% of the manufacturing costs for nitrogen fertilisers, cheap natural gas is the main driver for the expected build up of new nitrogen fertiliser plants and revamp of existing ammonia facilities in the US. New developments in the US will be key for T&T as the US is expected to become increasingly important in petrochemicals and bulk agro chemicals. This has already lead to the decline in imports seen in 2014, and we expect to see a continuing decline in US ammonia, urea and UAN imports as new capacity is built.

The list of identified projects (greenfield, brownfield and debottlenecks) shown in the table below show that there is around 6 MMt/y of new ammonia capacity expected on stream in in North America mainly in the US by 2018.

Table H-13 North America Planned Ammonia/Fertiliser Capacity Additions

(source: company data)

Company	Location	State	Capacity kt			
			Ammonia	Urea	UAN	Start
PCS Nitrogen	Lima	Ohio	110	88		2015
OCI/Iowa Fertilizer Company	Wever	Iowa	850	850	1700	Late-2015
CF Industries	Port Neal	Iowa	849			2016
CF Industries	Donaldsonville	Louisiana	1274	1348	1768	2016
Dyno Nobel	Waggaman	Louisiana	880			2016
Koch Fertilizer	Enid	Oklahoma	160	900		2017
J. R. Simplot	Rock Spring	Wyoming	210			2016
Agrium	Borger	Texas	146	612		2016
LSB Industries	El Dorado	Arkansas	375			2017
CHS Inc	Spiritwood	N Dakota	770			2017
Mosaic	St. James Parish	Louisiana	800			2018

In addition to the list of plants shown above, there are a whole host of proposed projects for ammonia and nitrogen derivative capacity, totalling more than 10 MMt/y of ammonia capacity. These proposed projects are at varying stages of development, and while we do not expect most of the plans to come to fruition, several undoubtedly will go ahead.

Although current projections (based on new supply projects which are reasonably firm) do not show the US as a net exporter of nitrogen, there are many other planned capacity additions. If these plans came to fruition, the US could become a net exporter, and it would have to export to the emerging economies of Asia Pacific and South America. This would put US producers/exporters into competition with T&T for these markets. T&T, which mainly produces ammonia for the US market, will potentially be seriously affected as it will have to find new markets. In Asian markets T&T will see competition from the existing Middle East exporters to the region plus new US exporters. However, T&T's location would give it a logistical advantage over USGC ammonia and nitrogen exports to the growing South American market.

H.4.3.4 Ammonia Trade

T&T is the world's largest exporter of ammonia (4.3 MMt in 2013), followed by Russia (3.4 MMt in 2013) and Saudi Arabia (1.6 MMt in 2013). Canada exports ammonia to the US (1.2 MMt in 2013) and Australia and Indonesia exported around 0.7-0.8 MMt to the Asian markets in 2013. Global ammonia trade has remained fairly constant over the last decade as most ammonia is consumed at its production site, with global trade standing at around 18 MMt/y for 2013 and 2014. The major ammonia trades are shown in the table below.

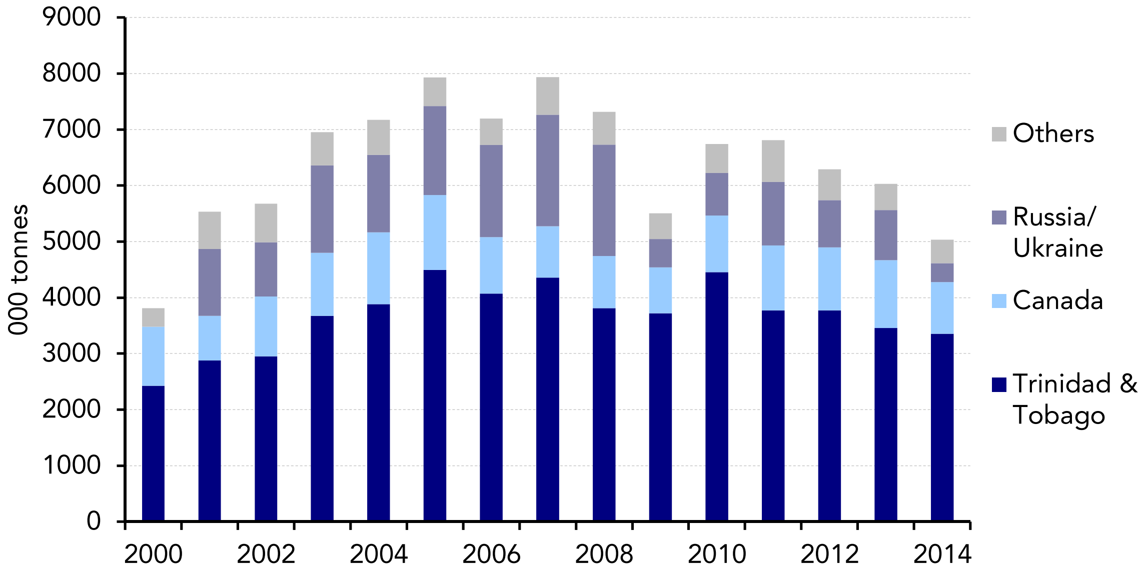
Table H-14 2014 Ammonia Trade Patterns

(source: Eurostat, USITC,UN)

Country	Imports 2014 MMt	Main sources (Volume MMt)
US	5.0	T&T (3.4) Canada (0.9) Russia/Ukraine (0.4)
EU 28 (2013 figures)	3.4	Russia (1.0) Algeria (0.5) Ukraine (0.2)
India (2013 figures)	1.9	Iran (0.5) Qatar (0.4) Saudi (0.4) Ukraine (0.3) Russia (0.1)
Korea	1.2	Saudi (0.5) Australia (0.3) Malaysia (0.1) Indonesia (0.1)
Brazil (2013 figures)	0.4	T&T (0.4)
Morocco (2013 figures)	0.6	Ukraine (0.5)
Turkey (2013 figures)	0.6	Ukraine (0.5)
China (2013 figures)	0.3	

Figure H-56 US Ammonia Imports

(source: USITC)



By far the largest ammonia trade flow is from T&T to the US where it is used in direct application of ammonia and to produce fertilizer and chemical products. India and Korea are also significant importers of ammonia, with imports mainly sourced from the Middle East and South East Asia. In the Atlantic basin, Morocco imports sizeable volumes of ammonia, for production of phosphate fertilisers.

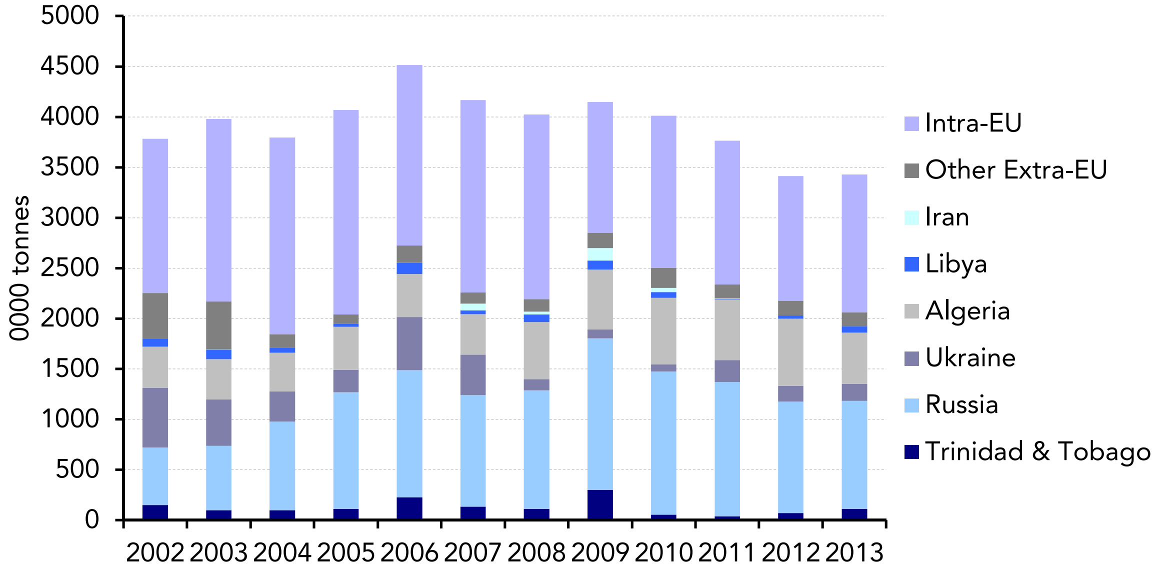
Brazil is one of the fastest growing fertilizer markets. It imported 4.4 MMt of urea in 2014. It also imported 0.4 MMt of ammonia. In future, Brazil's demand for nitrogen and imports of ammonia are expected to increase as regions with phosphate reserves, including Brazil, typically lack nitrogen capacity and will need to import ammonia for new phosphate production.

European Ammonia Trade

Europe currently is much less an important market for T&T's ammonia than the US, with EU28 countries importing 0.1 MMt of ammonia from T&T in 2013, compared with over 3 MMt of imports from the US.

The European market for ammonia (Western and Central Europe) stood at around 20 MMt in 2013. Although ammonia is traded within Europe, it is mainly consumed at the site of production. Imports for Europe stood at just over 4 MMt, with EU 28 countries accounting for nearly 3.5 MMt of imports. Aside from intra-EU movement of ammonia, the main suppliers into the market are Russia and Algeria.

Figure H-57 EU 28 Ammonia Imports
(source: Eurostat)



H.4.3.5 Urea Trade

Urea is much more easily transported relative to ammonia. According to IFA, global urea trade amounted to around 45 MMt/y out of global demand for urea 169 MMt in 2013. China is the largest urea market, both in terms of demand and production. Chinese demand for urea is estimated at 54 MMt in 2013, with production at 62 MMt, dwarfing the second largest producer India which produced 23 MMt of urea. The largest urea importers are India and the US, with the major trade flows outlined in the table overleaf.

Table H-15 2014 Urea Trade Patterns

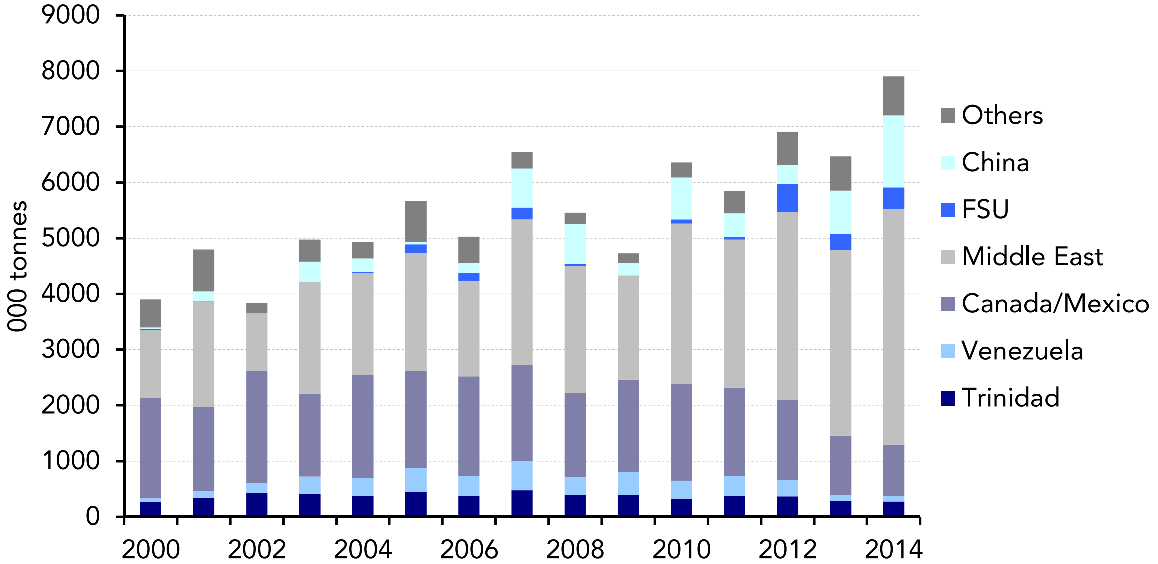
(source: Eurostat, USITC,UN)

Country	Imports 2014 MMt	Main sources (Volume MMt)
India (2013 figures)	8.6	China (3.6) Oman (2.4) Iran (2.0) Ukraine (0.3) Indonesia (0.2)
US	7.9	Qatar (1.4) China (1.3) Canada (0.9) UAE (0.7) Saudi (0.6) Oman (0.5) Russia/Ukraine (0.4) Bahrain (0.4) Kuwait (0.3) T&T (0.3)
EU 28 (2013 figures)	6.7	Intra-EU (3.1) Egypt (1.4) Russia (1.0) Ukraine (0.4) Qatar (0.2) Belarus (0.2)
Brazil	4.4	Qatar (1.1) Russia (0.8) Kuwait (0.6) Oman (0.5) UAE (0.3) Venezuela (0.2) Argentina (0.1) China (0.1) Saudi (0.1) Ukraine (0.1) Bahrain (0.1)

During 2014, there were significant disruptions in nitrogen capacity in Ukraine and Egypt. This led to a large increase in Chinese urea exports (which reached a record 14 MMt, or 30% of global trade of 47 MMt) to fill the market.

T&T's exports of urea currently are much smaller than its ammonia and methanol exports. However, downstream integration into urea instead of ammonia exports could provide a possible market outlet for ammonia production.

Figure H-58 US Urea Imports
(source: USITC)



H.4.4 Ammonia Pricing

Ammonia prices reflect the global supply and demand for ammonia and nitrogen fertilisers, with a floor price determined by the economics of the marginal global producer. The marginal highest cost production is currently ammonia/urea produced from Chinese coal. We expect that global pricing will continue to be supported by the need for production from higher cost regions including Ukraine and Western Europe, with Chinese coal-to-ammonia economics providing a floor price. New production in low cost gas regions including new US production will be price takers.

H.5 PETROCHEMICALS COMPETITIVENESS

H.5.1 Overview

T&T has historically enjoyed a competitive position for its exports of methanol and ammonia into the North American market. For the North American market, T&T, being nearer, benefitted from a logistics advantages relative to competing global suppliers. More importantly, T&T benefitted from the availability of competitively priced supply of natural gas compared with domestic North American producers and other exporters such as Russia and Norway.

The rise of shale gas in the US offers prospective producers there an abundant source of competitively priced natural gas in the same location as existing customers for T&T's methanol and ammonia. New production will substantially diminish the import need (including for T&T product).

Poten has assessed the relative economic competiveness of T&T's ammonia and methanol suppliers into global export markets against global producers. The competiveness has been assessed for year 2020 using the following pricing assumptions.

Table H-16 Competiveness Analysis
(Source: Poten)

Methanol Economics		2020 FCT
Methanol Price	USGC contract - $/T	326
T&T Gas Price for Methanol[4]	$/MMBtu	2.51
Ammonia Economics		
Ammonia Price	FOB Black Sea - $/T	303
Henry Hub Price	$/MMBtu	4.66
T&T Gas Price for Ammonia[4]	$/MMBtu	3.44
Regional Gas Prices		
Henry Hub	$/MMBtu	4.66
Saudi Arabia	$/MMBtu	0.75
Russia	$/MMBtu	3.50
Ukraine	$/MMBtu	8.00

We expect T&T to remain a competitive exporter into Atlantic basin markets, but US and Canadian producers are expected to be more completive into the North American market. It should be noted that this analysis is based on the prices that are paid to NGC for gas supply. Were NGC's margin from upsteam to reduce then T&T's competitiveness would increase.

H.5.2 Competeveness of T&T Ammonia

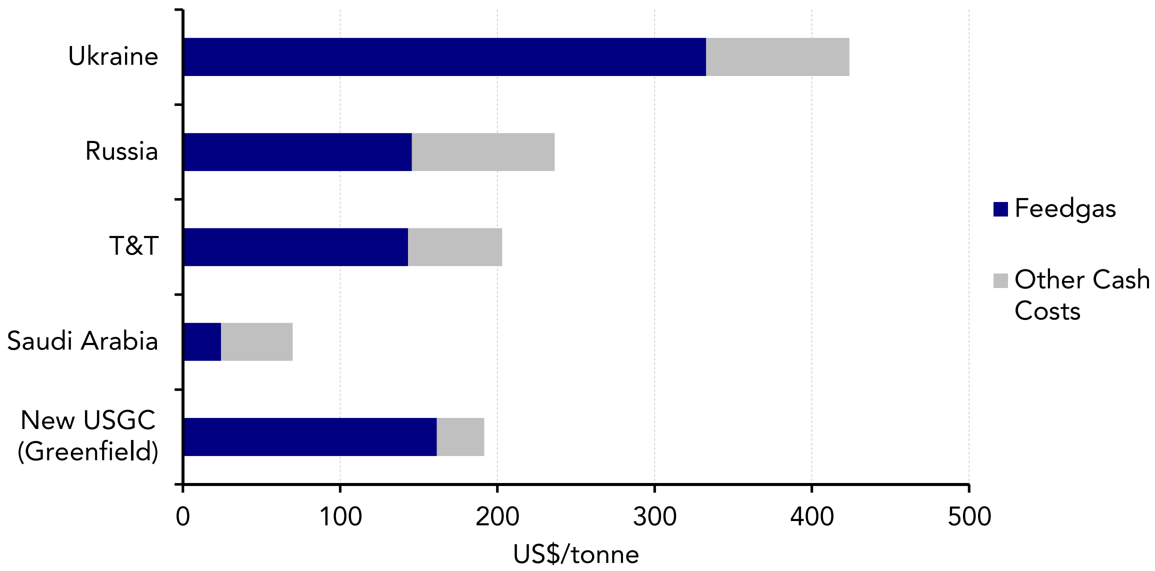
For ammonia, T&T's competeveness has been assessed against ammonia producers in the US, Middle East and Black Sea. On an FOB basis, T&T ammonia production is competitive against the major

[4] Average paid projected to be paid to NGC from methanol/ammonia at this methanol/ammonia price

potential exporters into the Atlantic basis market, including new USGC producers. Only Saudi Arabia has a substantially lower cash cost of production, but will be expected to target markets east of Suez.

Figure H-59 Ammonia Competiveness (Cash Cost FOB) - 2020

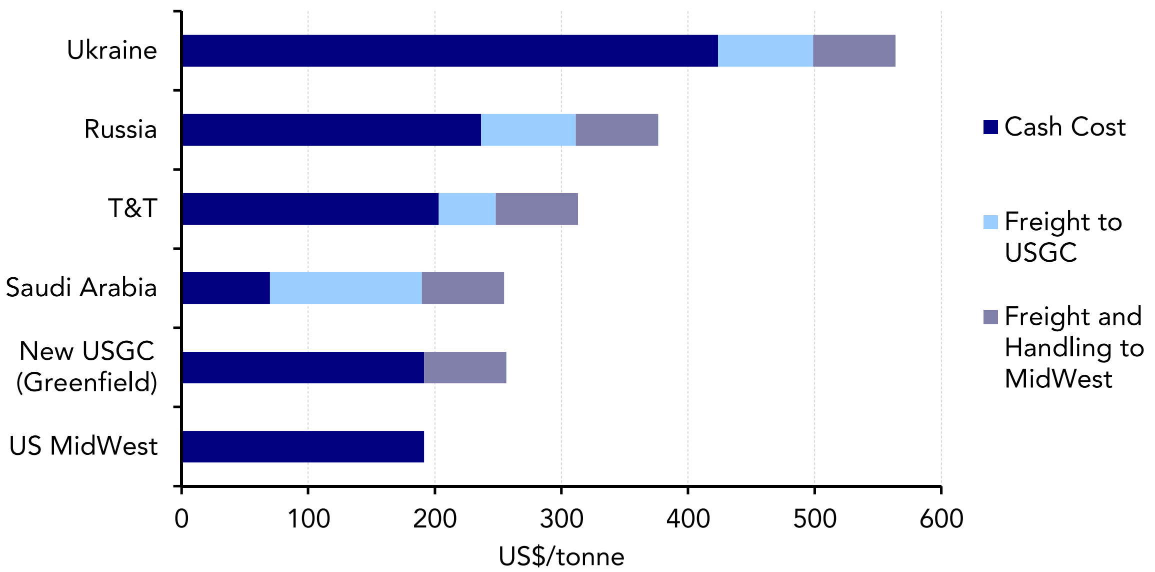
(source: Poten Estimates)



Looking at the competiveness of T&T on a delivered basis into the US Midwest which is currently the main end market for T&T's production, we see that US Midwest and USGC producers will be able to competitively displace T&T ammonia from this market.

Figure H-60 Ammonia Competiveness to US Midwest Market - 2020

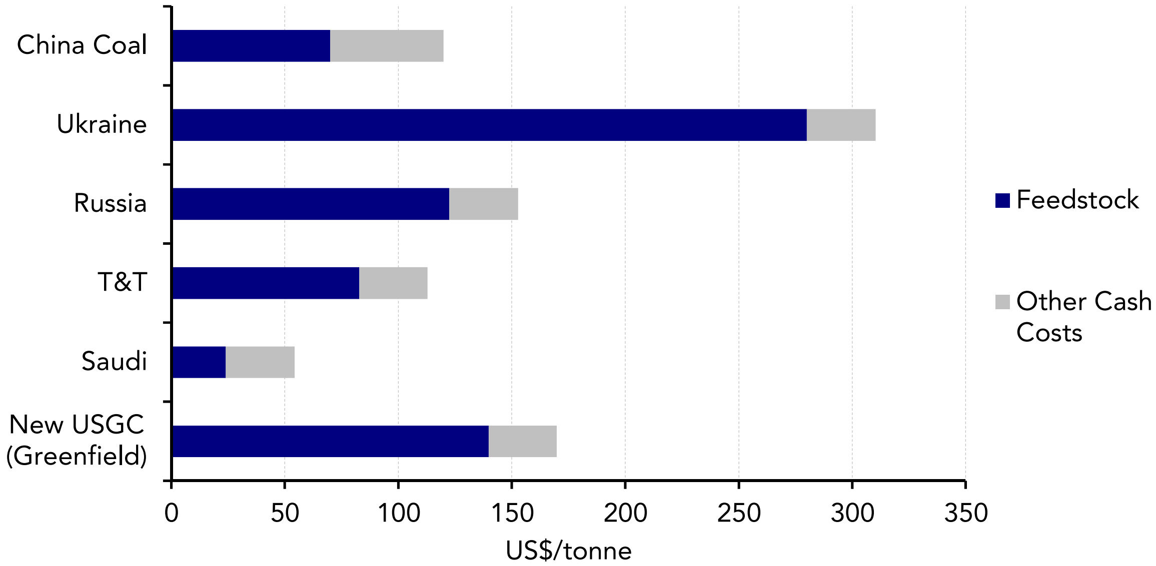
(source: Poten Estimates)



H.5.3 Competiveness of T&T Methanol

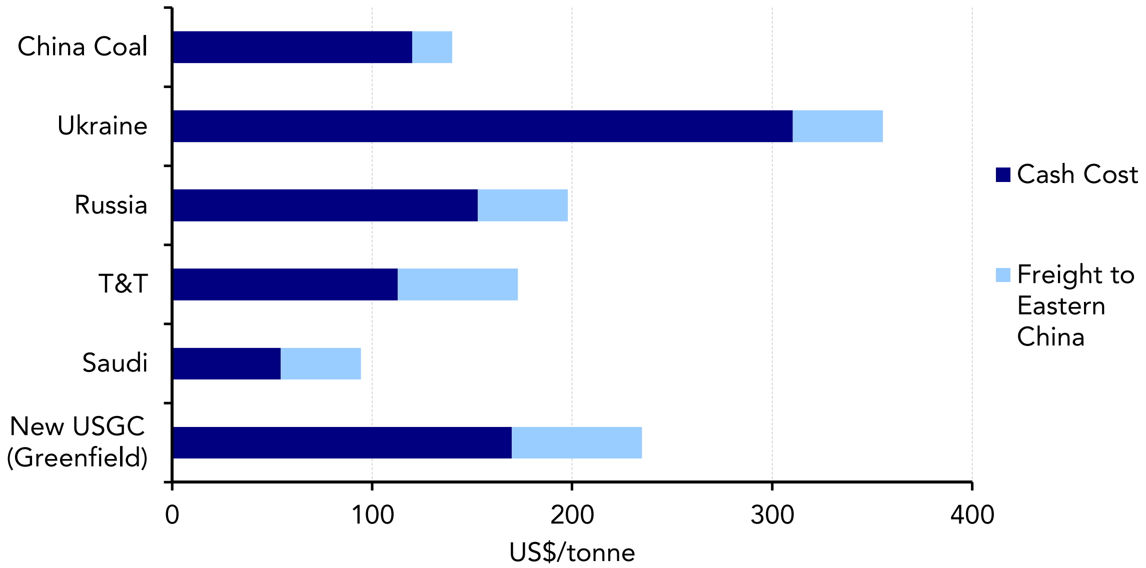
For methanol, T&T's competiveness has been assessed against methanol producers in the China, the US, Middle East and Black Sea. On an FOB basis, T&T methanol production is expected to have a lower cash cost than new greenfield USGC capacity. Methanol is a truly globally-traded commodity which is easily transported. At the margin, T&T methanol production will compete into global markets on a fob basis. On this basis, T&T can compete with USGC exporters, and it is only producers with extremely low-cost gas such as Saudi Arabia which have lower methanol production costs.

Figure H-61 Methanol Competiveness (FOB) - 2020
(source: Poten Estimates)



The competitive position of T&T methanol is demonstrated further by comparing the delivered cash costs into the Eastern China coastal market. Here, T&T gas-based methanol has a lower delivered cash cost than other major exporters (including prospective US-based producers). Only Saudi Arabia has a lower delivered cash cost. The cost of T&T methanol delivered to Eastern China is similar to our estimated costs of Chinese coal-based production in the west of the country.

Figure H-62 Methanol Competiveness to Chinese Market - 2020
(source: Poten Estimates)



H.6 IRON & STEEL PRODUCTION

H.6.1 Introduction

Iron and steel have been manufactured in T&T since 1980. Iron production uses the Direct-Reduced Iron (DRI) process which utilizes natural gas as a feedstock and iron ore that is brought in from Brazil. The DRI product, also called sponge iron, is produced from direct reduction of iron ore and is produced in the form of lumps, pellets or fines. Steel is manufactured from some of the DRI produced using an Electric Arc Furnace (EAF) process and processed into product in what is known as a mini-mill.

The specific investment and operating costs of DRI plants are low compared to integrated steel plants and are generally more suitable for many developing countries where supplies of coking coal are limited[5]. DRI is an excellent feedstock for the electric furnaces used by mini mills, allowing them to use lower grades of scrap for the rest of the charge or to produce higher grades of steel.

There are two iron and steel manufacturers in the country:

- ArcelorMittal owns and operates an iron and steel mill located at Point Lisas, which initially started up in 1980, and currently has an annual production capacity of 2.7 MMt/y of DRI pellets. This plant was originally owned by GoRTT but was taken over by Ispat in 1989 and completely divested in 1994. The facility was subsequently upgraded to become an integrated plant with an additional 1.36 MMt/y DRI plant and electric arc furnace (EAF) type steel melt shop of 600,000 t/y, a wire rod mill of 420,000 t/y and ancillary facilities. The production upgrade increased the output of the facility to 1,168,000 t/y of DRI, 1,000,000 t/y of billets and 734,000 t/y of wire rods. Ispat was eventually was subsumed into the Arcelor Mittal group.
- Nucor owns a 1.6 MMt/y DRI facility that was established as Nu-Iron in Port Lisas in late 2005. The plant was built with equipment shipped from Nucor's decommissioned Convent, Louisiana plant in the USA. This plant had become uneconomic due to the high gas prices in the US at this time.

H.6.2 Industry Structure and Competition

The steel industry is highly cyclic and has gone through several cycles in the last few decades where demand growth has led to overcapacity in the industry which is then followed by a wave of consolidation or closures. In the 1980's static steel consumption led to massive closures and consolidation of steel capacity in Western Europe and North America.

From about 2000 there was a further round of consolidation and privatisation among steel companies in both those regions and in Eastern Europe, leading to the emergence of the ArcelorMittal group as by far the largest steel producer in the world. That group has a particularly strong position in flat products[6]. This concentration has reduced competition in flat steel products in the EU, where there are only a few locally-

[5] The tradition mode of steel production was utilizing a blast furnace to manufacture iron from iron ore using metallurgical coke and limestone, the products are molten iron and slag. A basic oxygen furnace e.g. a Bessemer converter, is used to convert molten iron into molten steel. The electric arc furnace (EAF) has emerged as an alternative smaller-scale approach, which essentially combines these two approaches into one. In an EAF various forms of iron are used as feed together with flux material and large quantities of electricity to directly produce molten steel. The feed for an EAF can be scrap iron, DRI, pig-iron, hot metal, or HBI.

[6] Flat products include slabs, hot-rolled coil, cold-rolled coil, coated steel products, tinplate and heavy plate. They are used in automotive, heavy machinery, pipes and tubes, construction, packaging and appliances. Long products include billets, blooms, rebars, wire rod, sections, rails, sheet piles and drawn wire. The main markets for these products are construction, mechanical engineering, energy and automotive.

based suppliers. In other areas of the world, however, consolidation has not created dominant regional producers in flat products and competition remains strong. Long steel production has many more companies and low regional concentrations, so issues of competition are generally insignificant.

Much of the steel market is national or regional. The developments since 2000 have created global steel companies with operations across regions (ArcelorMittal, US Steel, Tata, Severstal, NLMK), as well as companies with a regional focus (Posco and Japanese producers with affiliates in China and South East Asia). Those companies are likely to present themselves as global suppliers of high quality products, a development towards the international corporate structure of the non-ferrous metals industry. Some of this globalising expansion was ill-advised and has been reversed, particularly the ventures into the USA by Severstal, who acquired uncompetitive plants. Chinese producers can also be expected to expand outside China and to raise the quality of their products to become major international competitors, modelling themselves on the experience of the Japanese and Posco of South Korea.

The great diversity of products and markets means that there will still be room for national or local suppliers, particularly in less sophisticated products such reinforcing bar and commodity-grade plate and welded tubes.

H.6.3 International Trade

Steel products are widely traded between countries and the volume of that trade has steadily increased as a proportion of production. This trend can be expected to continue and to be reinforced by the trend towards free trade and the growth of tariff-free regional trading blocks. The entry of China and Russia into the World Trade Organisation in 2011-2012 further opened the trade flows.

These trends will increase the opportunities for steel exports. As noted earlier, steel companies have become more international and this trend will continue. Greater freedom of trade and removal of tariffs continued against the backdrop of recession in 2009-12, when an increase of trade barriers might otherwise have been expected. The steel industry retains strong political influence in many countries and it can be expected that anti-dumping measures will be used whenever excessive imports threaten the stability of the domestic industry. Hence, while there are more opportunities for trade, there is also a risk that successful exporters may face specific anti-dumping efforts unless they can demonstrate to the authorities of the importing country the validity of their competitive advantage. T&T has significant experience of the use of such trade barriers in the past when the US Government imposed import duties on exported DRI from the T&T ISCOTT plant (which today is operated by ArcelorMittal).

In 2014 the slowdown in the steel market in China led to a massive increase in exports of finished steel products from China to nearby countries and further afield into the USA, South America and Europe. This will provoke a strong anti-dumping response and in the short term trade restrictions may increase, contrary to the long-term trend. Offsetting the potential growth of international trade will be the increase in the costs of steel transport. Greater use of larger ships or more systematic use of containers for shipping steel could reduce the cost impact and there may be opportunities for better organisation of ocean transport of steel products, including the operation of shipping fleets by steel companies.

H.6.4 Current Status of the Global Steel Industry

The global steel sector is currently facing a number of challengers, with tight margins caused mainly by an excess of capacity in a market for which demand is only just starting to show signs of recovery and a volatility in the price of iron ore and steel meaning that much of the available margin is being held within what is considered to be a highly illiquid upstream market.

The situation has worsened since 2000 when the industry was operating at above 80% capacity and it was forecast that around 60 MMt of unused capacity would need to be removed in order to for the market to be balanced out. Now, following investment in the industry, which is set to continue, less than 80% of available production capacity is being used. Despite this, the production of steel has continued to increase from approximately 850 MMt in 2000 to 1,606 MMt in 2013.

The challenges that are being faced by the steel industry include:

- Governmental intervention and the political advantage of creating or retaining jobs, regardless of profitability
- A shift in demand in traditional high-end products, such as infrastructure, towards the developing economies
- The need to meet a developing demand for more innovative products within the high-end market.
- A high volatility and lack of liquidity within illiquid upstream raw materials market.

Things are starting to show signs of improvement with regards to demand as the world starts to emerge from the current economic crisis and enter into a new phase of growth. Demand for steel is being driven, for example, by the urbanisation, and associated need to develop infrastructure, within some of the emerging economies and a demand for innovative, high-end, products to satisfy the need for cleaner automotive products in more developed OECD economies. Many of the players in the steel sector will need to make decisions as to whether to adapt to the changing demands of the markets within which they are already established with new products or to enter new geographic markets into which demand for traditional high-end products is shifting, such as China and Africa.

The oversupply of capacity will need addressed be during the coming years. Older, less efficient, steel works will need to close and there is expected to be a number of consolidations across the sector, particularly in China, where the government has mandated that 80 MMt/y of capacity be removed by 2018, but it is estimated that the amount of capacity that would need to be removed would be in the order of 300 MMt/y, or around 10% of current capacity.

There has also been a move by steelmakers to address the issue of volatility and retention of increased margins within the upstream raw material supply markets as part of the overall value chain, mainly though vertical integration. For example, POSCO and China Steel purchased a stake iron ore mines in Canada and Evraz invested in Russian coal production.

Financial instruments have also been used more and more as a means of hedging exposures to the volatility and liquidity risks associated with raw materials needed by steel producers.

H.6.5 Global Outlook for Steel Consumption

Consumption of steel products follows the trend of economic activity in individual countries. There is a clear trend for high levels of consumption of steel products at certain stages of economic development, which are associated with rapid urbanisation and construction, combined with industrialisation and the growth of manufacturing industry. The urbanisation and construction provide strong demand for steel long products (bars, sections) and some flat products (plate and galvanised sheet for construction), while the growth of manufacturing industry provides demand for flat products (hot- and cold-rolled coil, stainless steel, etc.).

As more developing countries pass through this phase, following on a smaller scale the path of China from the mid-1990s onwards, steel demand will increase rapidly in some parts of the world. The other clear long-term trend is that steel consumption stabilises or starts to fall in relation to GDP at high levels of income per head. This means that there will continue to be slow growth in steel consumption in the developed countries of North America, Western Europe and Japan.

The steel market has a relatively heavy dependence on the automotive and construction sectors. These are among the most cyclically variable of industries. Hence the steel market will continue to experience large cyclical movements in demand and companies need to structure their operations and organisations to cope with these fluctuations without major financial losses.

H.6.6 DRI Production

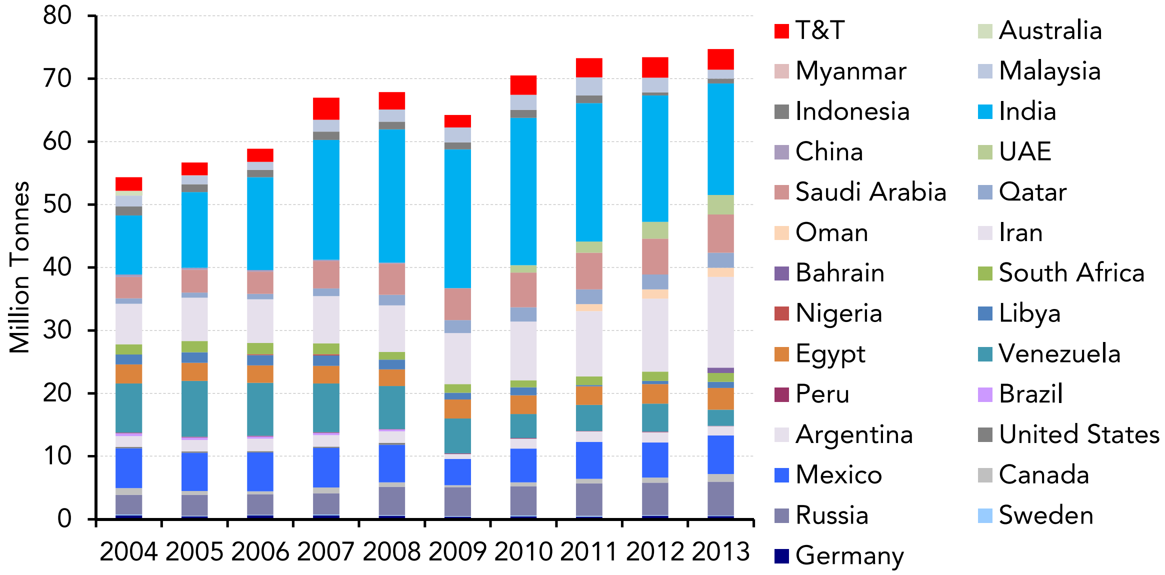
DRI production has increased steadily over the last decade with a downward blip in 2009 following the financial crisis. Output last year was more than 85% greater than in 2001. Factors that had placed a drag on growth in the preceding years continued, but were overshadowed by the demand for direct reduced iron in many areas. T&T accounts for 4% of global DRI production, which has remained stable for the last decade.

The global production of DRI in 2013 was 74.7 million tons, a 28% increase over 2005. India is the largest single producing country (17.7 MMt) followed by Iran (14.4 MMt) and Mexico (6.1 MMt). There are 164 DRI facilities worldwide. Most DRI is produced in the Middle East a (28 MMt/y) followed by Asia (20 MMt/y), and North America (10.6 MT/y - which includes 3.2 MT/y production from T&T). Latin America which in 2000 was the world's largest producing region has now dropped to sixth place. DRI production from Venezuela has dropped by two thirds over the last decade from 7,825 MMt in 2004 to 2,584 MMt in 2013.

The primary region of industry growth was the Middle East /North Africa region where more than five million tons more DRI were made than in 2012. Bahrain entered the group of DRI producing nations with a new 1.5 MMt/y facility and Iran demonstrated major growth, increasing output by nearly three million tons primarily via the ramp-up of a number of recently commissioned modules. Libya increased tonnage as industry there continued to rebuild from the civil war. Outside of MENA, additional growth was also seen in Russia, which had a new national record production of 5.3 MMt.

The growth seen in 2013 was quite remarkable since two key producing countries, India and Venezuela, saw a significant decline in production. In India main reasons for the decline were the difficulties due to lower availability of domestic iron ore due to regulations and licensing related to environmental requirements and extremely high prices of natural gas. As a result a number of companies in India are building facilities to make DRI using syngas produced from coal in place of natural gas. Two of these facilities are expected to be commissioned in 2014.

Figure H-63 Global DRI Production
(source: World Steel Association)



Venezuela continued to struggle with DRI production down 40% from 2012. The immediate reason is a shortage of iron oxide pellets to feed the DR plants, but the underlying reason is lack of funds for maintenance throughout the supply chain; mining, transportation, materials handling, pelletizing, iron-making and infrastructure.

H.6.6.1 New Production Capacity

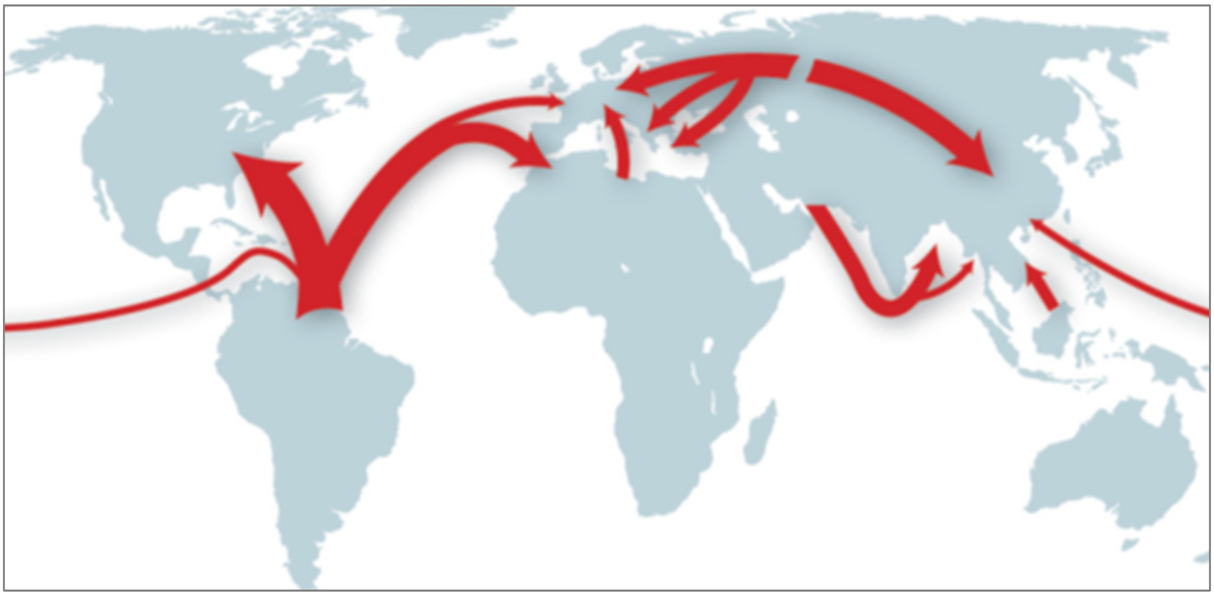
Six Midrex DRI modules are under construction in five countries; Egypt, India, Iran, Russia and the United States. They are slated for commissioning in 2014-2016 and have a combined capacity of 10.1 MMT/y. Three HYL/Energiron modules are contracted or under construction in Egypt, India and Venezuela. They have a combined capacity of 5.2 MMt.

Shale gas exploration in the USA and Canada has led to lower natural gas pricing in North America encouraging the building of new DR capacity. One plant has already begun commercial operation and another project broke ground for construction in April of this year. More facilities are expected to be contracted in the USA over the next few years.

H.6.7 DRI Trade

Some 7.2 MMt of DRI product was internationally traded in 2013, some 10% of the global production. T&T is the world's largest exported of DRI, and in 2013 exported 2.3 MMt equivalent to 70% of its DRI production. Only Russia has DRI exports of a similar magnitude (2 MMt), and these two countries dominate global trade with 60% of global trade between them.

Figure H-64 Major Global DRI Trade Routes
(source: Midrex)



In contrast to other regions, exports from Venezuela declined. Whereas, Venezuela at its peak in 2005 was shipping nearly 4 MMt/y of DRI to numerous markets, in 2013 shipments had fallen to a fraction of that (0.8 MMt).

The longer term outlook for trade is positive. New plants in Russia and Texas in the USA, will be adding to the global trade when they are commissioned.

H.6.8 Demand and Supply issues

H.6.8.1 DRI Sales for Export

All exports of DRI would be in the form of HBI, as this is a safer product for international transport by sea. The total world export market for DRI was 9.0 MMt in 2013 and probably less in 2014. The export market peaked in 2012 at 10.8 MMt and has not increased significantly since 2002. Our forecasts show the total world export market for DRI rising to 9.7 MMt in 2020 and 12.3 MMt in 2030. Our forecasts show that the only significant importers of DRI in North and South America over the forecast period are expected to be:

- USA (1.80 MMt in 2020)
- Canada (0.20 MMt in 2020)
- Mexico (0.28 MMt in 2020)

Imports into Canada and Mexico will probably be by the affiliates of ArcelorMittal that now use domestic DRI production supplemented by imports from ArcelorMittal's plants in T&T, depending on the relative cost positions at those plants. The prospects for sales to Canada and Mexico are therefore limited.

Consumption of DRI in the USA will depend on the price of DRI relative to steel scrap. There is an expectation that high quality steel scrap will become increasingly scarce, so that larger quantities of primary iron, as DRI or pig iron, will be needed by the US industry. Our forecasts show an increase in consumption of DRI/HBI from 2.4 MMt in 2014 to 5.7 MMt by 2020 and 6.4 MMt by 2030. This rapid increase in the short term is because of an expansion of DRI capacity in the USA by Nucor. This is assumed to replace imports and also to increase the use of DRI in place of scrap and pig iron.

Voest-Alpine of Austria also has a DRI plant under construction in the US, with the stated intention of exporting the product to its operations in Austria. This may be part of a long-term plan to close integrated steel production at the company's plant at Donawitz in Austria, together with an associated local iron ore mine. Nevertheless, transport costs for DRI from the USA to Austria will be high and alternative raw materials may be available from Eastern Europe, so some of the plant's DRI could be sold in the US market.

The forecast large increase in consumption is likely to put pressure on imports, which could be lower than our current forecast of 1.8 MMt in 2020 and 2.3 MMt in 2030. The main sources of imported DRI for the USA have been T&T (1.8 MMt), Venezuela (1.5 MMT tonnes until 2006, but only 340,000 tonnes in 2013) with occasional quantities from Canada and Russia.

The USA has had no significant exports of DRI, but is forecast to start exports in coming years. The total production of DRI is expected to increase from nothing in 2013 to 4.0 MMt by 2020 and 4.6 MMt by 2030. Given the planned expansion of capacity for DRI in the USA, based on low-priced natural gas caused by massive new gas supply capacity is expected to reach 9 MMt by 2018 and to exceed requirements throughout the period to 2030.

The only producer of DRI in the USA was Georgetown Steel (now part of ArcelorMittal) in South Carolina, using the product to produce high-grade wire rod. This plant operated intermittently according to the price of gas. In the late 1990's new DRI capacity was built at a time of low gas prices, but did not operate for technical or cost reasons. Given the expected surplus position of DRI in the USA, exports would probably need to be to more distant markets.

Forecasts of imports into the main countries of Europe by 2020 are:

- Spain: 0.65 MMt
- Turkey: 0.42 MMt
- Netherlands (possibly for Germany): 0.28 MMt
- Germany: 0.26 MMt
- Italy 0.34 MMt

These are mainly sales to electric steelmakers for blending with scrap to improve steel quality in the production of long products. Annual sales to individual consumers may be relatively small (under 100,000 tonnes). The main sources of supply for these countries have been Russia (Lebedinsky), Trinidad (ArcelorMittal) and Venezuela.

Asia is the other major market area for supply of DRI. Forecasts of imports into the main countries of Asia by 2020 are:

- China: 1.30 MMt (includes Taiwan)
- India: 0.58 MMt
- South Korea: 0.48 MMt
- Indonesia: 0.45 MMt

- Thailand: 0.22 MMt
- Malaysia: 0.18 MMt

China, Taiwan and South Korea use DRI as a supplement to scrap for higher-grade steel. In China there is also a large availability of pig iron that would keep DRI prices low. India, Indonesia and Malaysia are producers of DRI, so imports could be eliminated at any time by expansion of domestic capacity.

The prospects in the export market are therefore mainly for long-distance sales in relatively small individual quantities to electric steel producers in Europe and Asia. Overhanging the DRI market is the expansion of DRI capacity in the USA and the situation in Venezuela. In Venezuela there is 13 MMt/y of DRI capacity and production in 2014 was under 2 MMt. Peak production was in 2005 at 8.9 MMt and peak exports at over 4 MMt. So poor was the situation in Venezuela that domestic steel producers had to import DRI in 2012. It is likely to be some years before the political situation in Venezuela permits a return to higher levels of production and by that time some of the capacity, which has all been nationalised, may have become inoperable. The DRI industry in Venezuela has a fundamentally strong position of local iron ore, hydro-electric power and natural gas. If it can be revived in the medium and longer term it will be a strong competitor in the export market.

H.6.9 DRI, Steel and Raw Material Prices

Steel prices depend on the balance of demand and supply (utilisation of available supply) and the costs of production. The first shows a short-term fluctuation depending on the level of economic activity and the scale of capacity. The second depends on the movement of key input costs, mainly coking coal, iron ore and scrap.

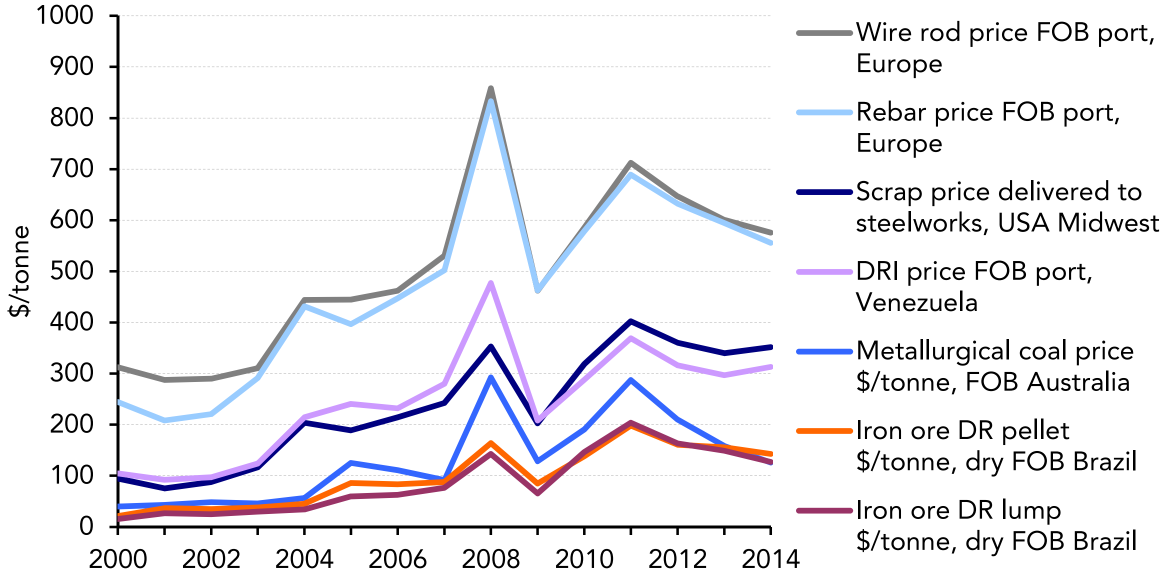
Prices for individual finished steel products tend to move closely together, despite having widely different end-use applications. This is probably because some producers are able to switch part of their production between products. For example, if the price of billets for constructional steel were high relative to the price of slabs for flat products, they could shift production into billets. Some producers can also shift from production of hot-rolled coil to bars or sections in such a situation. This is sufficient to ensure that prices of individual steel products cannot move significantly out of line over the medium term.

Steel prices vary between countries and this is generally due to the cost of bringing imports from an alternative source. This means, for example, that prices in the USA are generally higher than in other markets because the marginal product is an import from Europe or Asia carrying a transport cost of at least $50 per tonne. These differences persist, but in general steel prices in all countries move in parallel.

Steel prices are set by the vast number of negotiations between buyers and sellers, which are reported in the trade press and in market news.

Since about 2005 the key issue in the steel industry has become the availability and price of raw materials – iron ore, coking coal/natural gas and scrap. Demand from China drove the markets for iron ore and coal into tightness and the highly concentrated structure of the internationally traded markets for both products enabled prices to be raised to high levels, transferring profits from steelmakers to raw materials suppliers in the short term. Because of steel's strong position in its applications, those price increases could generally be passed on to customers after some time lag, so that the steel producers restored or even increased their profitability without losing volume to other materials.

Figure H-65 Price History of Marker Steel Products and Key Production Inputs
(source: MCI)



A period of sustained high capacity utilisation in the industry from 2005 eventually caused an extreme tightness in the market for steel and the price spike of 2008. The severe economic downturn in 2009 brought capacity utilisation and prices down to much lower levels. Since 2012 prices have moved closely in line with average production costs. Production costs themselves have become more variable over the short term as the pricing of raw materials has moved from an annual to a quarterly or shorter basis, with much greater influence of spot market conditions on those prices.

This pattern is expected to continue in the future, with the trend of prices continuing to depend on the underlying level of production costs for steel products. That will in turn depend on physical availability of iron ore and coal resources and the long-term trend in prices of energy, labour and capital equipment. Prices will fluctuate widely around that trend in response to short term changes in steel consumption.

The response to high prices for those materials has been threefold:

- An increase in investment in new iron ore and coal capacity by both the existing producers and by new entrants. That investment resulted in substantial new capacity starting production from 2012 onwards and continuing to add capacity for several more years.
- A move by steelmakers to acquire their own raw materials. This reversed a trend existing from the late 1970s where steelmakers in Europe and North America progressively closed or sold their own iron and coal operations because their costs were higher than the market prices of the products. Some western producers (particularly ArcelorMittal and Tata) and many Chinese producers have moved rapidly to acquire iron ore and coking coal operations or projects. This is changing the structure of the iron ore and coal markets, reducing the size of third-party sales at the same time as new competitors start up their capacity.
- A move by steel consumers in China to seek out new sources of supply from countries with previously small iron ore operations. Thus, large quantities of iron ore have been imported into China from Malaysia, Indonesia, Vietnam and Mongolia, which previously had only small iron ore industries. Chinese capital and enterprise has been used to expand the supply from these unconventional sources.

From 2014 these actions have resulted in lower prices for traded iron ore and coking coal. This will reduce the cost advantage of captive production, but it seems likely that companies with captive iron ore and coal supply will retain some of the large cost advantage that they had in 2012 and 2013. Access to captive iron ore and coal will remain a major strategic advantage of any producer already in that position or able to achieve it at reasonable investment cost.

Of the two main materials, coking coal is the one with the most problems of available resources. Deposits of high-grade coking coal appear limited and the capital, operating and transport costs of those deposits are high. This is likely to mean continued relatively high prices for good quality coal. This will drive the search for methods to reduce the use of coke, such as pulverised coal injection (PCI) on all new blast furnaces and retrofitting of existing furnaces. It will be one factor encouraging the use of the electric steel process in place of integrated steel.

Iron ore, on the other hand, has large resources potentially available to be mined. This includes major reserves in the existing largest producing countries, Australia and Brazil, as well as new resources to be developed in West and South Africa and elsewhere. Several factors will affect the future development of iron ore. These include:

- The high capital cost of infrastructure (railways, ports and towns) to open up the resources in remote areas of West Africa and parts of Brazil. This gives a large cost advantage to existing producers who can make incremental additions to existing infrastructure as they increase their capacity.
- Dwindling resources of the highest grades of ore. This means that natural high-grade ore products such as blast furnace and DR-grade lump ore will become increasingly scarce and consumers will have to switch to more processed products (sinter or pellets). It also means that there will be a gradual shift from natural high-grade hematite ores, on which, for example, the Australian, South African and Indian industries have been based, to magnetite ores with lower natural iron content and requiring concentration or pelletising to produce usable products.

The price of steel scrap tends to be determined by the prices of iron ore and coal, since the price of those materials determines the production costs of companies using them and therefore sets the baseline of prices with which scrap-based producers must compete. This meant high prices for scrap after 2005, prices far above the cost of collection and processing. Scrap prices were slow to fall from the peak levels, as demand for traded scrap was increased by the levels of steel production in China.

For the integrated process of steel production the main source of energy is coking coal, which is covered under raw materials above. Coking coal produces by-product energy gases that are used elsewhere in the plant instead of purchased natural gas or oil. Gas is the major fuel for the production of DRI, where it is reformed to provide carbon monoxide to reduce the iron ore. This process is economic only where the price of gas is relatively low, such as in countries of the Middle East. Electric steel plants and independent rolling mills are significant consumers of electricity. In some cases an electric steel plant generates its own electricity from natural gas. This is normally at electric steel plants associated with DRI (direct-reduced iron) plants, where natural gas is a major input to the iron making process.

H.7 T&T POWER SECTOR

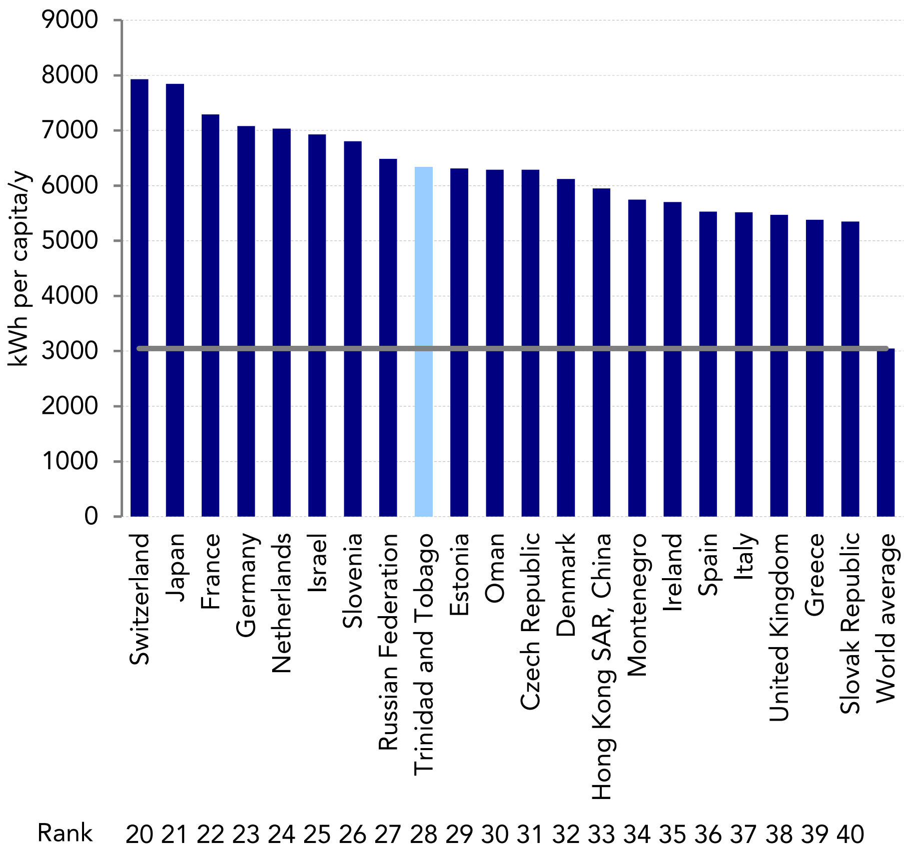
H.7.1 Introduction

T&T's 1.3 million population has annual per capita electricity consumption of 6,330 kWh (2011), ranking it 28th in the world (see Figure H-66), over twice the world average and consistent with its World Bank classification as a High-Income economy. Electricity generation in 2013 was 7.9 TWh, slightly higher than the previous year but significantly down on the 2011 value of 8.9 TWh (BP Statistical Review of the World 2014).

All of T&T's electricity is generated from natural gas. The government is, however, planning changes to legislation that will support electricity production from renewable energy sources, and in 2012 enlisted the UNEP to develop a framework for the introduction of feed-in tariffs7, which have been used successfully in many countries to boost renewable electricity production. The 2010 Finance Act introduced various incentives for solar and wind energy. In 2012 the Government commissioned a Wind Resource Assessment Programme with the aim of identifying candidate sites for wind farms (there is significant potential for wind generation on the east coast of Trinidad).

Figure H-66 Per Capita Electricity Consumption (2011)

source: World Bank)



[7] See "Feed-in Tariffs as a Policy Instrument for Promoting Renewable Energies and Green Economies in Developing Countries" - http://www.unep.org/pdf/UNEP_FIT_Report_2012F.pdf

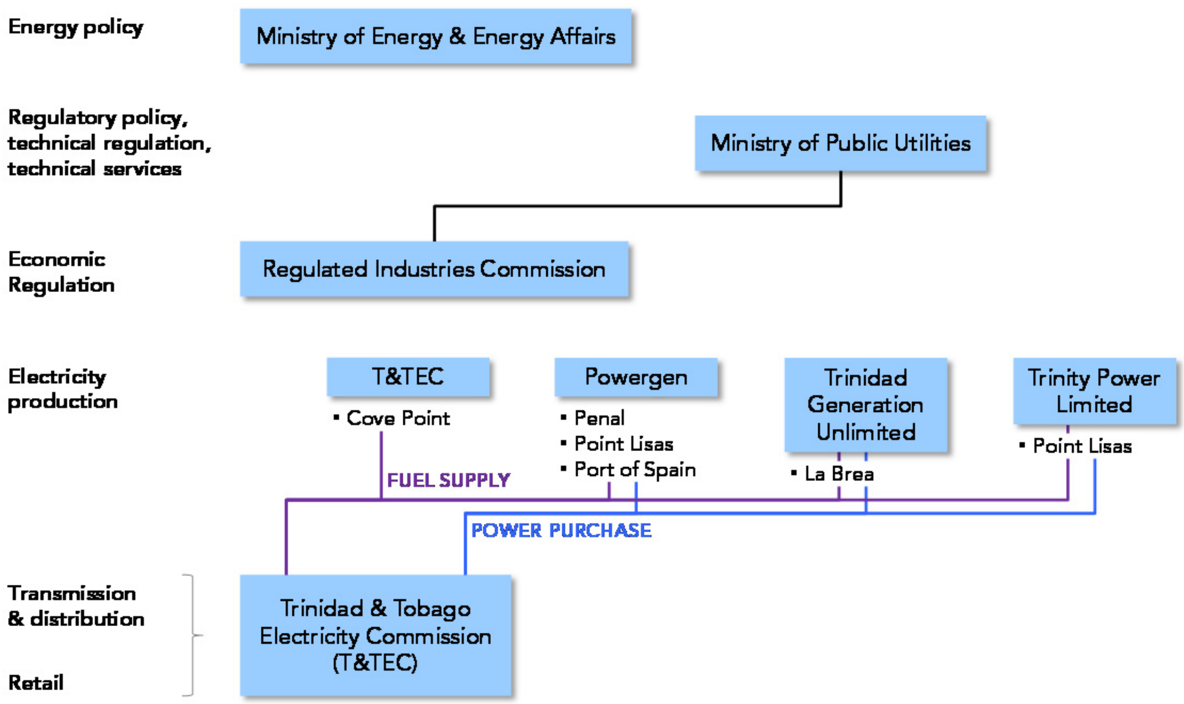
H.7.2 Industry Structure

The power sector in T&T remains predominantly state-owned, despite attempts over the years to increase private sector participation through Independent Power Producers. T&T has three power generating companies – Powergen, Trinity Power Limited and Trinidad Generation Unlimited – and the T&T Electricity Commission (T&TEC), which is responsible for transmission, distribution and sales (retail). T&TEC buys power from the generating companies, which it transports and sells to electricity consumers. T&TEC's responsibilities comprise:

- Electricity transmission;
- Electricity distribution;
- Ownership and operation of the Scarborough and Cove Point power stations, Tobago;
- Fuel purchase, for supply to the power generating companies;
- Power purchase from the power generating companies;
- Sales to end users (retail);
- Street lighting.

Electricity tariffs and quality of service standards are regulated by the Regulated Industries Commission (RIC). Investment in power generating capacity is controlled by the government; T&TEC in effect proposes its generation expansion plan, which includes specific project proposals that require government approval.

Figure H-67 T&T Electricity Industry and Regulatory Framework



H.7.2.1 Power Generation

T&T has 2,155 MW of installed capacity to serve a peak demand of around 1,400-1,500 MW, as shown in Table H-17, almost all (97 %) on Trinidad. All of T&T's power generation uses natural gas as fuel. T&TEC is responsible for ensuring that the country's generation capacity is adequate to meet the national demand at all times. The existing generating companies (Gencos) are mostly state-owned and controlled, but operate as Independent Power Producers, selling services to T&TEC under long term Power Purchase Agreements (PPAs). The current PPAs are tolling agreements – T&TEC provides the fuel (natural gas), which it purchases from the National Gas Company of T&T Limited (NGC), which is converted by the Gencos to electricity.

New power generation projects are implemented by T&TEC through competitive tender for Independent Power Producers (IPPs) to develop projects on a Build Own Operate (BOO) basis with long term PPAs.

Table H-17 T&T Power Plants

Power Station	Location	Generating Company	Technology	Capacity[8]
Port of Spain	Port of Spain, NW Trinidad	Powergen	Steam, OCGT	290
Point Lisas	Point Lisas, W Trinidad	Powergen	OCGT	635
Penal	Penal, SW Trinidad	Powergen	OCGT, CCGT[9]	210
TPL, Point Lisas	Point Lisas, W Trinidad	Trinity Power Limited (TPL)	OCGT	225
La Brea	SW Trinidad	Trinidad Generation Unlimited (TGU)	CCGT	720
Scarborough	Tobago	T&TEC	Engines	11
Cove Estate	Tobago	T&TEC	Engines	64
Total				2,155

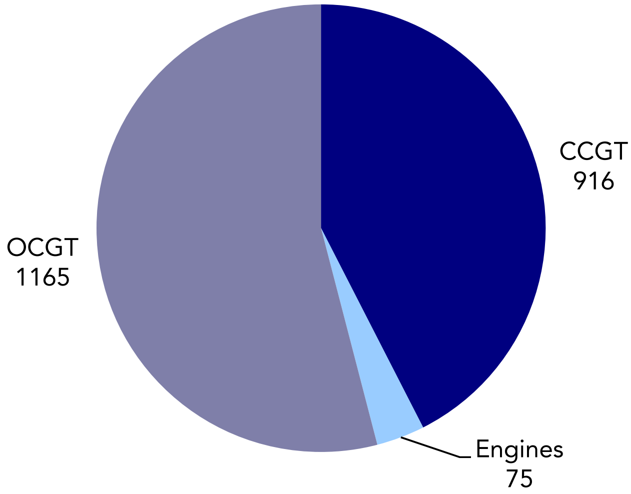
Table H-18 Generating Company Ownership

Generating Company	Ownership
Powergen	T&TEC (51%), Marubeni (19.5%), Abu Dhabi National Energy Company (TAQA) (19.5%), BP (10%)
Trinidad Generation Unlimited (TGU)	GoTT (100%)
Trinity Power Limited (TPL)	Carib Power Management LLC (100%)
Carib Power Management LLC is in turn owned by two US companies: Power Management Company (50.1%) and MDU Resources (49.9%).	

[8] Fifteenth Report of the Joint Select Committee on Ministries, Statutory Authorities and State Enterprises (Group 2) on the Administration and Operations of T&TEC, 2014.
[9] CCGT = combined cycle gas turbine, i.e. a power plant that generates electricity from one or more gas turbines and uses the heat in the exhaust gases to raise steam to produce additional electricity from a steam turbine. The efficiency of a combined cycle plant is typically about 50% higher than the equivalent open cycle gas turbine (OCGT), i.e. gas turbine only.

All the power plants are fuelled by natural gas, although the engines at Scarborough and Cove Point on Tobago have liquid fuel as back-up. 54 % of the existing capacity is OCGT, 43 % CCGT, and the balance is dual-fuel engines.

Figure H-68 Plant Mix
(All the power plants are gas-fired)



H.7.2.2 Transmission and Distribution

T&TEC was established in 1945 by the T&TEC Act as a corporate body, taking over from the Trinidad Electricity Board. It is 100 % state-owned, and is responsible for the design, construction, operation and maintenance of the Republic's electrical transmission and distribution network.

The maximum voltage on the transmission network is 220 kV, and it operates at a frequency of 60 Hz. T&TEC's transmission and distribution network includes over 1,300 km of high and medium voltage overhead lines and underground cables. There is also a subsea connection from Trinidad to Tobago comprising two 42km 33 kV AC submarine cables rated at 15 MW each.

H.7.2.3 Sales

T&TEC has agreements to secure the supply of electricity from generating companies, which it then transports and sells to consumers. T&TEC has about 460,000 customers in total, of whom about 3,700 (0.8 %) are industrial, the remainder residential and commercial.

Power Purchases

T&TEC has Power Purchase Agreements (PPAs) with each of the generating companies (Table H-19) for the provision of generating capacity (MW) and ancillary services, and the conversion of natural gas provided by T&TEC to electrical energy.

Table H-19 T&TEC Power Purchase Agreements

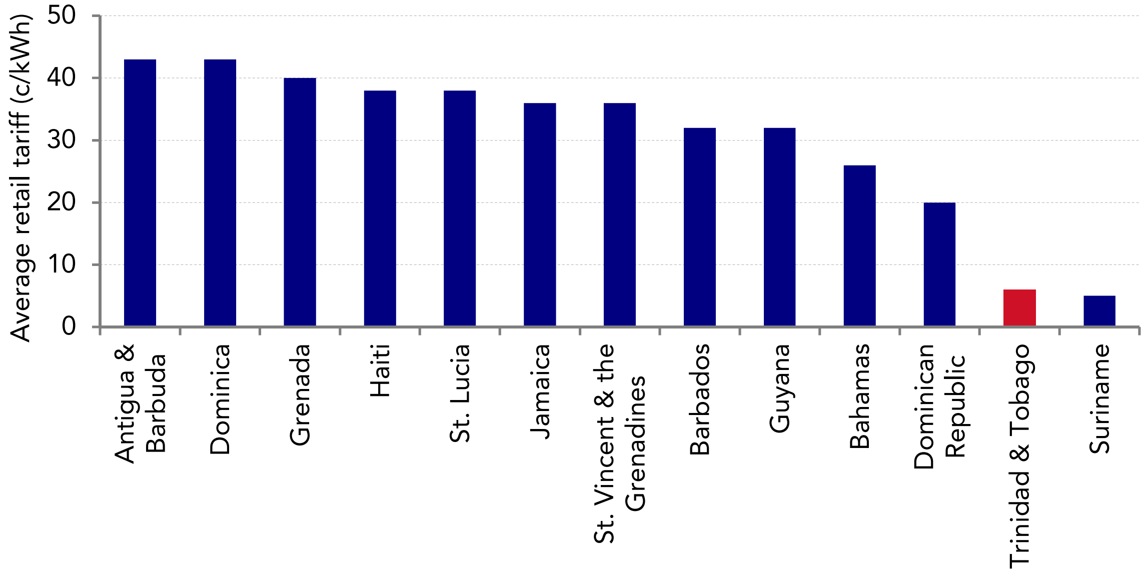
Agreement	Company	Capacity	Expiry	Notes
1998 PPA	Trinity Power	210	2029	30-y contract.
2005 PPA	Powergen	208	2035	30-y contract. From Point Lisas
2009 PPA	Trinidad Generation Unlimited (TGU)	720	2046	35-y contract.
2014 PPA	Powergen	742[10]	2030	15-y contract for power from the Penal and Port of Spain power plants. The PPA provides a sequenced decline in power generation from 819 MW in the previous PPA to 742 MW in 2014 and 624 MW in January 2016. Fuel efficiency incentives.

Electricity Tariffs

The Government has kept the price of electricity low in order to provide affordable power to the population. Presently electricity for residential use is around US$0.06/kWh11, which is very low by global standards, and particularly low by Caribbean standards, where power on other islands is generated by burning liquid hydrocarbons. Indeed in other Caribbean countries the price can be more than five times as much (US$0.30/kWh and above).

Figure H-69 Average Retail Tariffs in Caribbean Countries, 2012

(some tariffs from 2011, source: IADB)



The cost of electricity to industry in T&T ranges from 2.25 US¢/kWh (heavy industry) to 3.4 US¢/kWh for small and medium industry. The effective gas price realised by NGC for sales to the power sector is low at about US$1.40/MMBtu (projection for 2015 in T&TEC 2011-16 Business Plan). The average system thermal efficiency was projected to be only 32.7 % (LHV basis), despite the expected high utilisation of the new La Brea CCGT power station.

[10] 2014
[11] T&TEC tariff published on website: https://ttec.co.tt/services/tariffs/default.htm.

H.7.2.4 Regulation

The regulatory framework is illustrated in Figure H-67. Prices are controlled by the Regulated Industries Commission (RIC) on a cost-reflective basis. Price controls have been set for five-year periods, although the timing of the next review appears uncertain. The RIC in its 2006 Price Determination set an overall annual revenue cap for electricity transmission and distribution services based on RPI – X formula (X was set at 4.4 %).

H.7.3 Statistics

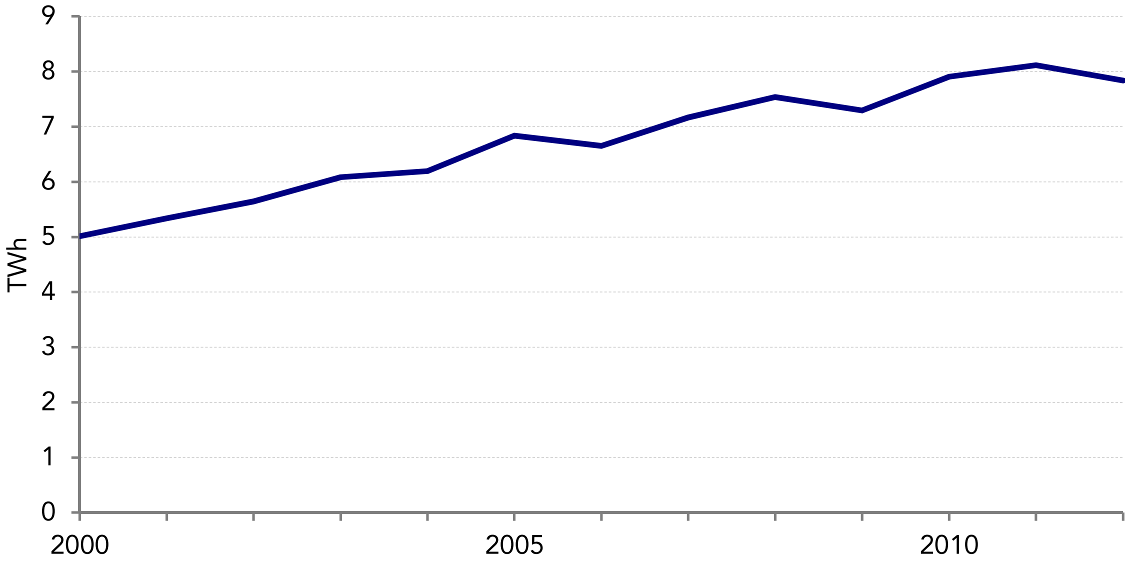
There is little publicly-available data about the power sector published on a regular basis apart from monthly gas consumption for power generation, published by the Ministry of Energy & Energy Affairs in the Monthly Bulletins.

H.7.3.1 Electricity Demand

T&TEC has close to 440,000 customers, serving 99 % of the population. The major part of electricity consumption is on Trinidad, which has 95 % of the Republic's population. Electricity consumption grew at an average of around 4.5 % per annum in the period 2000 to 2010, and peaked in 2011, but has since dropped. Peak demand in 2010 was 1,222 MW.

Figure H-70 Electricity Consumption

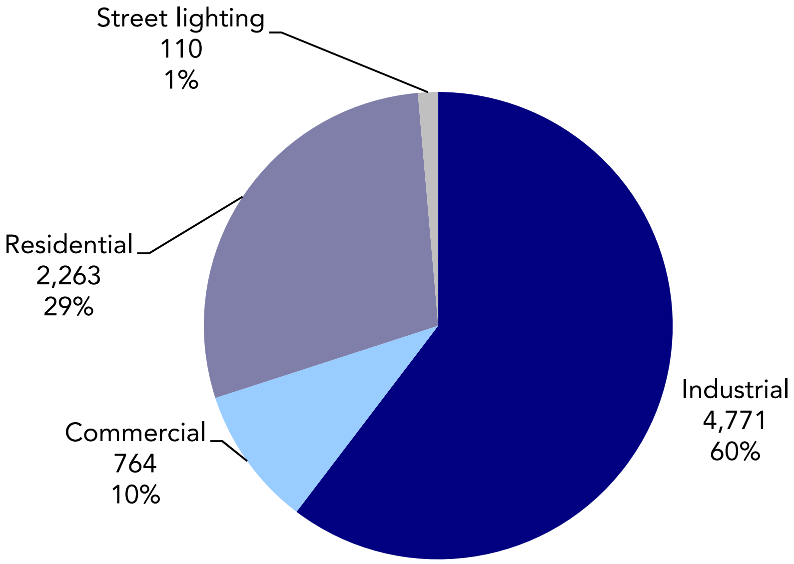
(source: BP, T&TEC Business Plan 2011-16)



The two biggest sectors are industrial and residential demand, which account for 59% and 30% of demand respectively (see Figure H-71. The fastest growing sector is residential demand (7.6 %/y), followed by industrial (3.8 %/y), leading to projected growth from 2011-16 of 4.8 %/y (source: T&TEC Business Plan 2011-16).

Figure H-71 Electricity Consumption by sector

(GWh (2010) and & of total, source: T&TEC Business Plan 2011-16)



H.7.3.2 Electricity Supply

Electricity supply is greater than consumption by the amount of transmission and distribution losses. In T&T these averaged 7 % of overall supply over 2005-10, or 7.5 % when expressed as a per cent of consumption. The level of losses varies year on year depending on demand and the infrastructure in place.

H.7.3.3 Gas Consumption

The gas requirement for power generation is presently around 305 MMscf/d, which is around 8% of total gas consumption. Average gas consumption has plateaued since 2011, assisted by the entry into service of the 720 MW La Brea combined cycle power plant (see Figure H-72). There is little seasonal variation – June is typically 3 % above the annual average and January about 4 % below (see Figure H-73).

Figure H-72 Power Sector Gas Consumption
(source: MEEA)

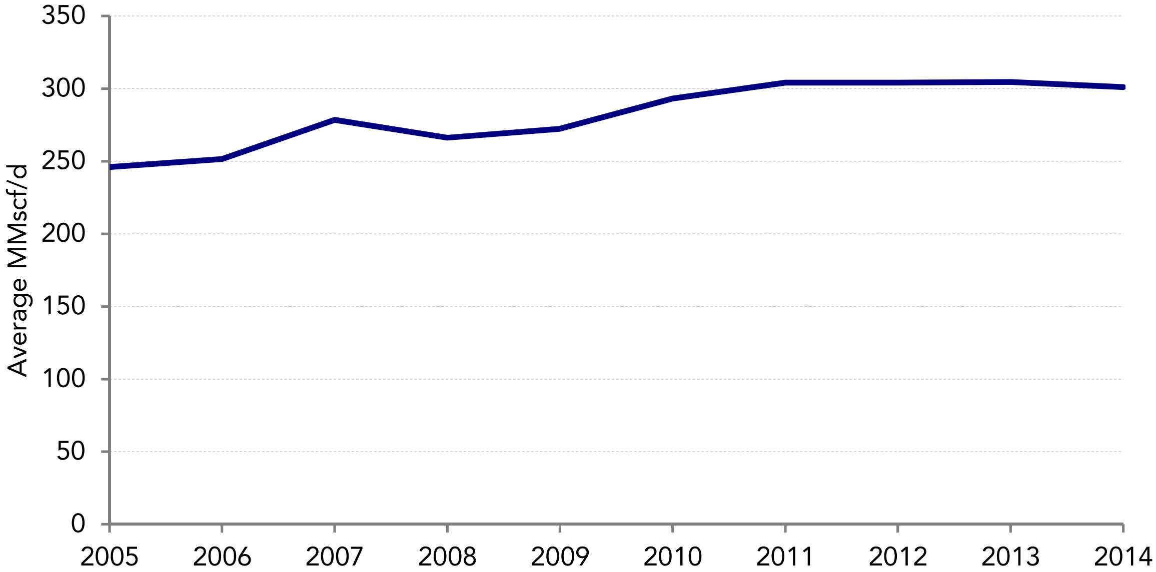
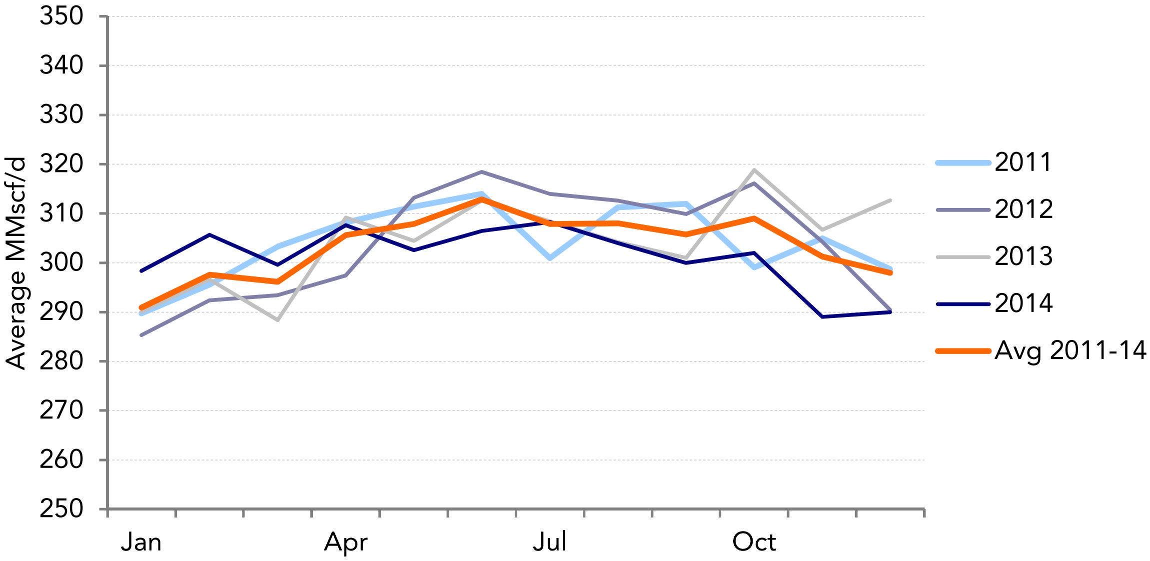


Figure H-73 Monthly Variation in Gas Consumption
(source: MEEA)



H.7.4 Plans

T&TEC's investment plans include the ongoing maintenance of and upgrades to existing equipment and construction of new transmission and distribution infrastructure required to cater for forecast demand growth and maintaining network quality standards. Proposed investments in power generation are shown in Table H-20.

Table H-20 Proposed Power Generation Investments

Name	Location	Technology	Capacity	Start Year
El Socorro	San Juan, Trinidad	CCGT	300 MW	2017
Wallerfield 1	Nr. Valencia, central Trinidad	CCGT	400 MW	2021
Wallerfield 2		CCGT	300 MW	2027
TBD	East coast	Wind (onshore)	TBD	TBD

H.7.5 Opportunities

Although the gas consumed in power generation is relatively small compared to that of the LNG and industrial sectors there are opportunities to improve the levels of consumption and reduce overall gas demand. The generation fleet is entirely fuelled by natural gas but the majority of the capacity is inefficient open cycle plant rather than combined cycle (CCGT) which would give a higher thermal efficiency and therefore consume less gas per unit of electricity produced. The average efficiency of Powergen's units (1,135 MW) is only 24 %[12], and Trinity Power (225 MW) only 27 %. That said it is noted that the most recent plant installed at La Brea on the Union Estate in 2012 is a 720 MW CCGT plant.

It is government policy that future thermal power plants should be combined cycle to maximise the conversion efficiency. This should improve conversion efficiency from the low level of 32.7 % (LHV basis) projected by T&TEC in its 2011-16 Business Plan. However, there is little incentive to improve efficiency when gas prices are low, and even less when costs are in principle simply passed through to end users in the tariff. As stated in the introduction, the government is considering support for electricity production from renewable energy sources, which would increase the volume of gas available for gas-based industries.

[12] Source: Fifteenth Report of the Joint Select Committee on Ministries, Statutory Authorities and State Enterprises (Group 2) on the Administration and Operations of T&TEC, 2014. It is not clear whether the thermal efficiencies quoted were based on the Lower Heating Value (LHV) of fuel as is customary in the electricity supply industry or on the Higher Heating Value (HHV), which is the custom in the oil and gas business. Efficiency on LHV basis for natural gas fuel is higher than on HHV basis.

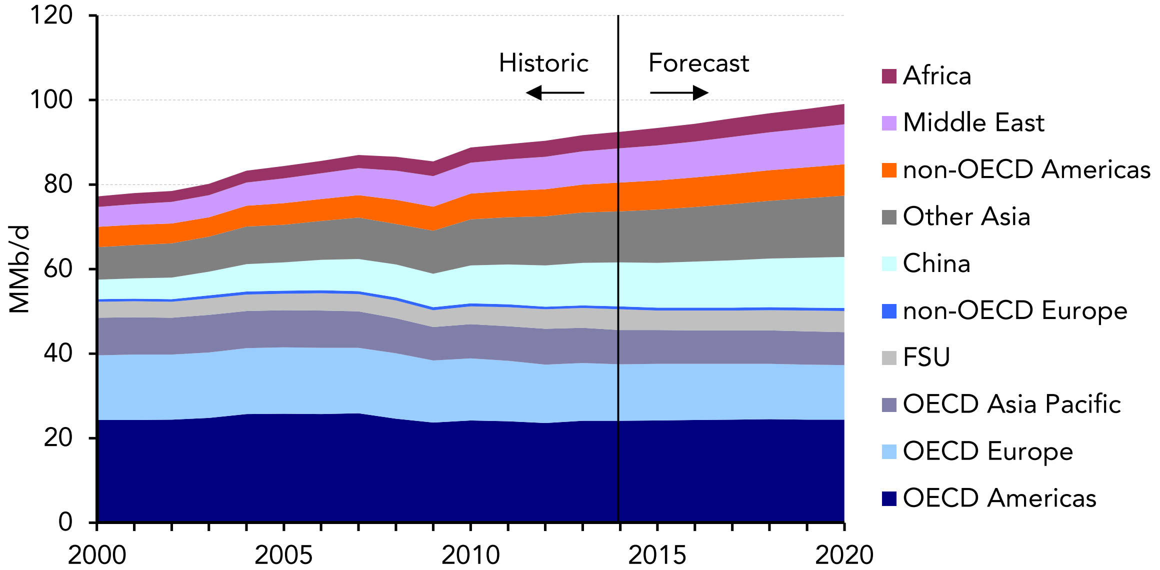
H.8 OIL SUPPLY & DEMAND

Global oil demand is projected to grow at an average rate of 1.2% p.a. over the next six years, reaching 99.1 MMb/d by 2020. The main trends that are expected are:

- Slowing demand growth in emerging economies including China as these countries enter less energy- (and oil-) intensive stages of their development. Service industries and other non-oil-intensive sectors increase their share of output in the economies of these countries.
- Declining oil demand in many developed economies including in the mature markets of Europe and Japan. Economic growth is stagnant and energy consumption patterns are increasingly moving away from oil as a result of efficiency gains and a move towards natural gas and renewables. The US is expected to buck the trend somewhat as the strong economy there is expected to lead to some oil demand growth there.

Figure H-74 Global Oil Demand by Region

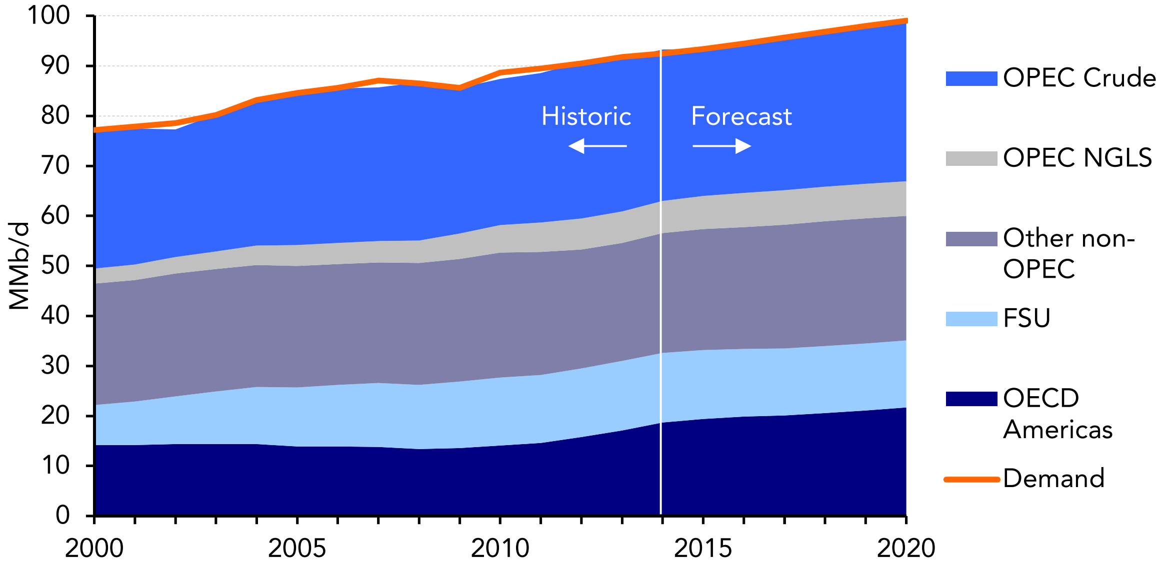
(source: IEA Medium Term Oil Market Report)



The oil price decline has stalled investment decisions, which will put the brakes on new forthcoming supply, and IEA forecasts see both OPEC and non-OPEC producers scaling back investment. The net result is a slowdown in global oil capacity growth to an annual rate of 860 kb/d between 2015 and 2020, compared with the 1.8 MMb/d in growth in supply witnessed in 2014. According to IEA projections global total oil capacity is expected to rise to 103.2 MMb/d by2020.

The most important recent development in oil markets has been the unlocking of the huge resource base of US unconventional supply from light tight oil (LTO). Production from the US has increased remarkably over the past three years, and the increase in this supply has been instrumental in the oil price collapse. Despite lower oil prices, US LTO production is expected to increase from 3.6 MMb/d in 2014 to 5.2 MMb/d in 2020, or more than one third of 2020 projected total US liquids production (14 MMb/d). Production from LTO has a fast lead time and its price-responsiveness allows it to act as a swing producer, responding to upside price movements, thus tempering future prices.

Figure H-75 Global Oil Supply and Demand
(source: IEA Medium Term Oil Market Report)



I.1 FINANCIAL ANALYSIS DATA & METHODOLOGY

I.1.1 Key Data Sources

The matrix below illustrates the key elements of the time-based data that was provided to Poten to enable the financial analysis of value chains of the various gas-based industries to be undertaken.

Table I-1 Data Matrix

Data	Source	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
ALNG T1-4 cargo-by-cargo price/revenue data	MEEA	Data received	Data received	Data received	Data received	Data received	Data received	Data received	Data received	Data received	Data received
ALNG T1 total LNG/NGL revenue	ALNG	Poten extrapolation	Poten extrapolation	Poten extrapolation	Data received	Data received	Data received	Data received	Data received	Data received	Poten extrapolation
ALNG T1 revenues by offtaker	ALNG	Poten extrapolation	Poten extrapolation	Poten extrapolation	Poten extrapolation	Poten extrapolation	Poten extrapolation	Data received	Data received	Data received	Data received
ALNG T1-4 feed gas volumes by supplier	ALNG	Poten extrapolation	Poten extrapolation	Poten extrapolation	Poten extrapolation	Poten extrapolation	Data received	Data received	Data received	Data received	Data received
ALNG T1 NGL revenue	ALNG	Poten extrapolation	Poten extrapolation	Poten extrapolation	Data received	Data received	Data received	Data received	Data received	Data received	Poten extrapolation
ALNG T1 feed gas costs	ALNG	Poten extrapolation	Poten extrapolation	Poten extrapolation	Data received	Data received	Data received	Data received	Data received	Data received	Data received
ALNG T2/3 total LNG/NGL revenue	ALNG	Poten extrapolation	Poten extrapolation	Poten extrapolation	Poten extrapolation	Poten extrapolation	Poten extrapolation	Data received	Data received	Data received	Data received
ALNG T2/3 NGL revenue	ALNG	Poten extrapolation	Poten extrapolation	Poten extrapolation	Poten extrapolation	Poten extrapolation	Poten extrapolation	Data received	Data received	Data received	Poten extrapolation
ALNG T2/3 Plant Net Entitlement by gas supplier	ALNG	Poten extrapolation	Poten extrapolation	Poten extrapolation	Poten extrapolation	Poten extrapolation	Poten extrapolation	Data received	Data received	Data received	Poten extrapolation
ALNG T4 Processing Fees by gas supplier	ALNG		Poten extrapolation	Poten extrapolation	Poten extrapolation	Poten extrapolation	Poten extrapolation	Data received	Data received	Data received	Data received
ALNG (by train)/PPGPL NGL production	MEEA	Data received	Data received	Data received	Data received	Data received	Data received	Data received	Data received	Data received	Data received
ALNG T1-4 taxes paid by train	ALNG	Poten extrapolation	Poten extrapolation	Poten extrapolation	Data received	Data received	Data received	Data received	Data received	Data received	Data received
ALNG T1-4 net profit by train	ALNG	Poten extrapolation	Poten extrapolation	Poten extrapolation	Data received	Data received	Data received	Data received	Data received	Data received	Poten extrapolation
Gas supplier flows & prices	NGC	Data received	Data received	Data received	Data received	Data received	Data received	Data received	Data received	Data received	Data received
NGC supply flows & prices	NGC	Data received	Data received	Data received	Data received	Data received	Data received	Data received	Data received	Data received	Data received
Methanol/Ammonia production by plant	MEEA	Data received	Data received	Data received	Data received	Data received	Data received	Data received	Data received	Data received	Data received
CNC/N2000 Corporation Tax	CNC/N2000	Data received	Data received	Data received	Data received	Data received	Data received	Data received	Data received	Data received	Data received
Total Ammonia / Methanol taxes	MEEA	Poten extrapolation	Poten extrapolation	Poten extrapolation	Poten extrapolation	Data received	Data received	Data received	Data received	Data received	Data received
Overall oil/petrochemical sector GORTT take	Central Bank	Data received	Data received	Data received	Data received	Data received	Data received	Data received	Data received	Data received	Poten extrapolation
GORTT oil sector take by company (non-MEEA)	TTEITI	Poten extrapolation	Poten extrapolation	Poten extrapolation	Poten extrapolation	Poten extrapolation	Poten extrapolation	Poten extrapolation	Data received	Poten extrapolation	Poten extrapolation
GORTT oil sector take by company (MEEA)	TTEITI	Poten extrapolation	Poten extrapolation	Poten extrapolation	Poten extrapolation	Poten extrapolation	Poten extrapolation	Poten extrapolation	Data received	Data received	Poten extrapolation
ALNG accounts	ALNG				Data received	Data received	Data received	Data received	Data received	Data received	
NGC Accounts	NGC	Data received	Data received	Data received	Data received	Data received	Data received	Data received	Data received	Data received	Data received
PPGPL Accounts	NGC					Data received	Data received	Data received	Data received	Data received	

Data received
Poten extrapolation

I.1.2 Other Data Sources

Other key data sources included the following:

- ALNG T1-3 contract/price summaries (source: ALNG)
- ALNG T2/3 example monthly statements for PFLE / Trinling (source: ALNG)
- ALNG T2/3 example price calculation for BP cargo (source ALNG)
- ALNG T2/3 Plant Net Entitlement worked example (source: ALNG)
- ALNG T4 Processing Fee worked example (source: ALNG)

I.1.3 Methodology

I.1.3.1 Upstream GORTT Take

- TTEITI data provided for oil sector take by company provided for MEEA (FY 2012 and FY 2013) and non-MEEA receipts (FY 2012).

- Overall annual oil sector GORTT receipts taken from Central Bank data.
- Using actual gas revenue (from LNG and sales to NGC) and assumed oil revenue based on oil production figures by company, GORTT take as a percentage of revenues was calculated.
- Extrapolations for tax receipts were made for other years based on scaling receipts by company for FY 2012 by total revenue by company per year versus FY 2012, then scaling again by overall oil sector GORTT receipts in that year to ensure that the totals matched.

I.1.3.2 LNG

Train 1

- Utilised ALNG cargo-by-cargo data to determine the realised FOB revenues under each of the LNG supply arrangements.
- Utilised Poten intelligence of actual LNG prices in the markets supplied and Poten estimates of shipping costs to determine FOB prices for "Poten Assessed End Market Prices".
- Scaled total revenue by offtaker from cargo-by-cargo data by total revenue figures from ALNG by train to ensure consistency, where available.
- Used revenue data and LNG sales volumes in MMBtu from cargo-by-cargo data to give average annual FOB LNG prices in $/MMBtu.
- Assigned NGL revenues to the different gas suppliers based on incomplete total NGL revenue figures. Extrapolations were made based on actual data and crude oil prices where actual revenue data was not provided.
- Calculated total revenues by supplier from LNG and NGL revenues.
- Extrapolated gas supply data by supplier from 2005 to 2009 based on actual supply data for 2010 to 2014 and actual LNG supply volumes.
- Extrapolated feed gas costs in $ for T1 for 2005 to 2007 based on data for feed gas costs as a percentage of total revenues for 2008 to 2014.
- Calculated feed gas costs in $/MMBtu from supply volumes and feed gas costs in $.
- Subtracted an NGL credit from the feed gas cost figure to ensure a fair comparison with gas supplied to NGC. NGL credit was calculated assuming that the NGL quantity in MMBtu had been sold at the price that NGC sold gas to PPGPL rather than as NGLs.
- Taxes paid taken from accounts for 2008 to 2011 and based on actual data provided by ALNG for 2012 to 2014. Taxes accounted for are: Corporate Tax, Green Fund Levy, Withholding Tax.
- Plant net profit taken from accounts for 2008 to 2013. For 2014 based on revenues minus feed gas costs, taxes and other costs extrapolated from earlier years' data.
- GORTT share of net profit based on NGC stake and GORTT stake in NEL.
- Upstream GORTT take in $/MMBtu calculated using the GORTT take as a percentage of revenues calculated under the Upstream GORTT Take methodology.

Train 2/3

- As per Train 1.

- Assigned actual NGL production by train to the different gas suppliers using actual data for Train 1 (bpTT) and extrapolations for Trains 2-4.
- Extrapolated Plant Net Entitlement (PNE) by gas supplier for 2005 to 2010 and 2014 based on actual data for 2011 to 2013 and the PNE worked example provided by ALNG.

Train 4

- As per Train 1.
- No other data sources were supplied to corroborate cargo-by-cargo revenue figures.
- Split total BG gas supply between NCMA (4% of total T4 supply), ECMA (19%) and CB (5%) by high-level data supplied by MEEA.
- Split total TTLNG gas supply between EOG & bpTT based on cargo-by-cargo data analysis.
- Extrapolated Processing Fees by gas supplier for 2005 to 2010 based on actual data for 2011 to 2014 and the Processing Fees worked example provided by ALNG.
- Subtracted Processing Fees from total revenues to give feed gas costs at the plant inlet in $.

I.1.3.3 PPGPL

- PPGPL accounts financials split into elements for ALNG NGLs and NGC NGLs based on respective production volumes.
- Split out financials then used to calculate:
  - Tax paid by PPGPL per MMBtu of gas supplied to NGC.
  - GORTT share (based on NGC stakes and GORTT stake in NEL) of post-tax NGL profit per MMBtu of gas supplied to NGC.

I.1.3.4 Ammonia

- NGC gas costs per plant calculated from gas price and volume data provided by NGC.
- NGC gas revenues per plant calculated from gas price and volume data provided by NGC.
- Shrinkage between gas purchased by NGC and supplied by NGC calculated from NGC data.
- Price paid to NGC per MMBtu of gas production calculated from NGC revenues and production before shrinkage.
- Estimated taxes paid by each plant by assuming a plant's share of total ammonia production was equivalent to its share of total GORTT receipts from the ammonia industry. Analysis excluded CNC and N2000 for which actual tax data was provided.
- GORTT receipts from NGL taxation and share of profits as per PPGPL methodology.
- Upstream GORTT take in $/MMBtu calculated using the GORTT take as a percentage of revenues calculated under the Upstream GORTT Take methodology.

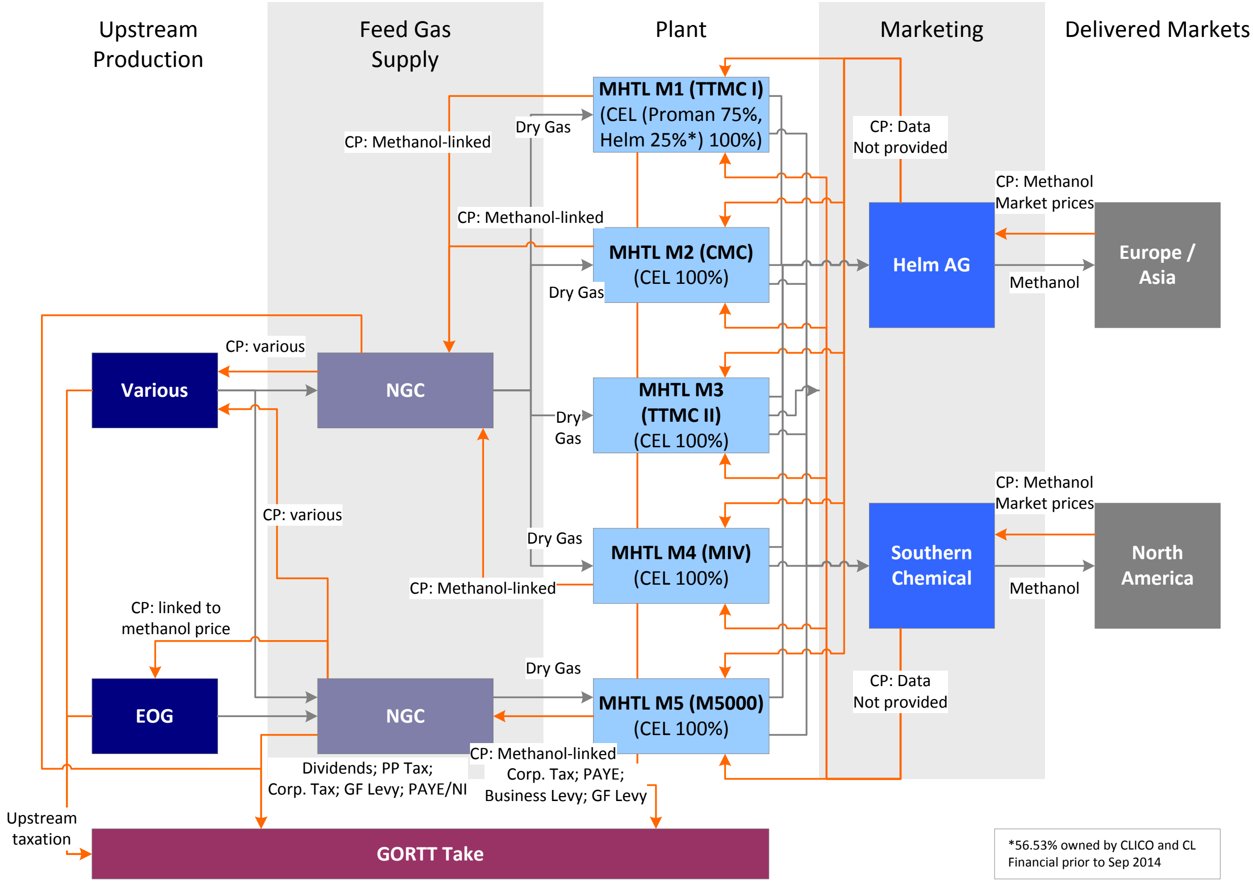
I.1.3.5 Methanol

- As per Ammonia.
- Estimated taxes paid by each plant by assuming a plant's share of total methanol production was equivalent to its share of total GORTT receipts from the methanol industry.

I.2 ADDITIONAL PHYSICAL, FINANCIAL FLOW GRAPHICS

I.2.1 Methanol

Figure I-1 MHTL Physical / Financial Flows



I.2.2 Ammonia

Figure I-2 Yara Physical / Financial Flows

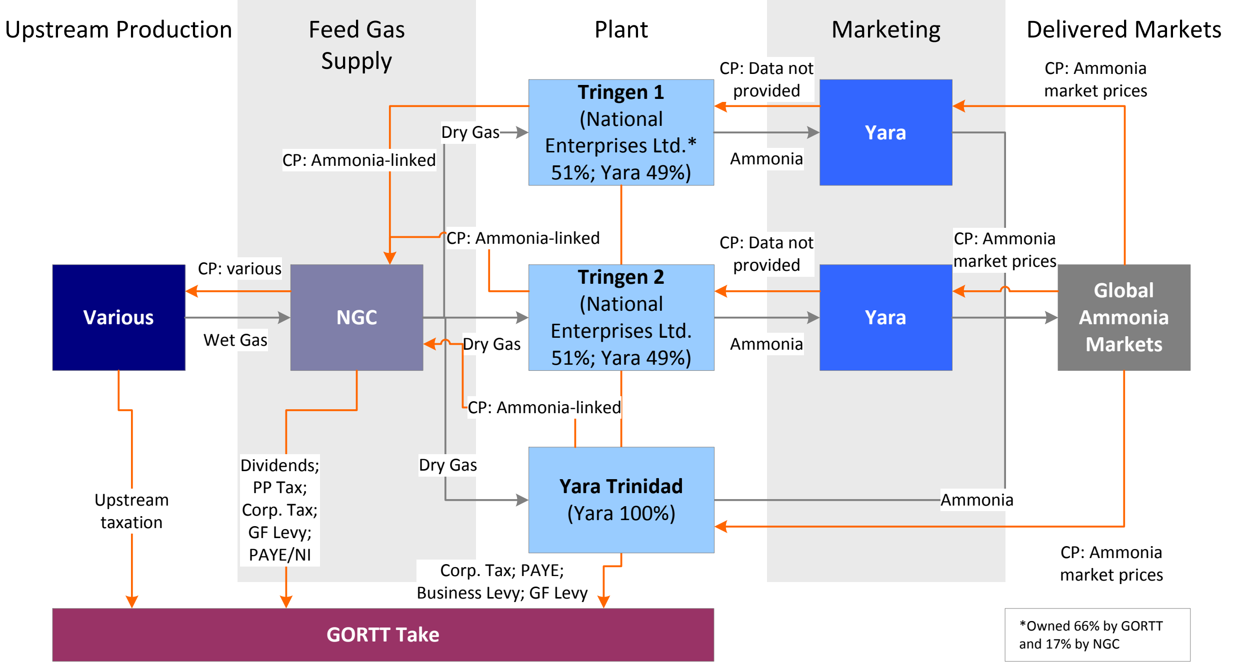
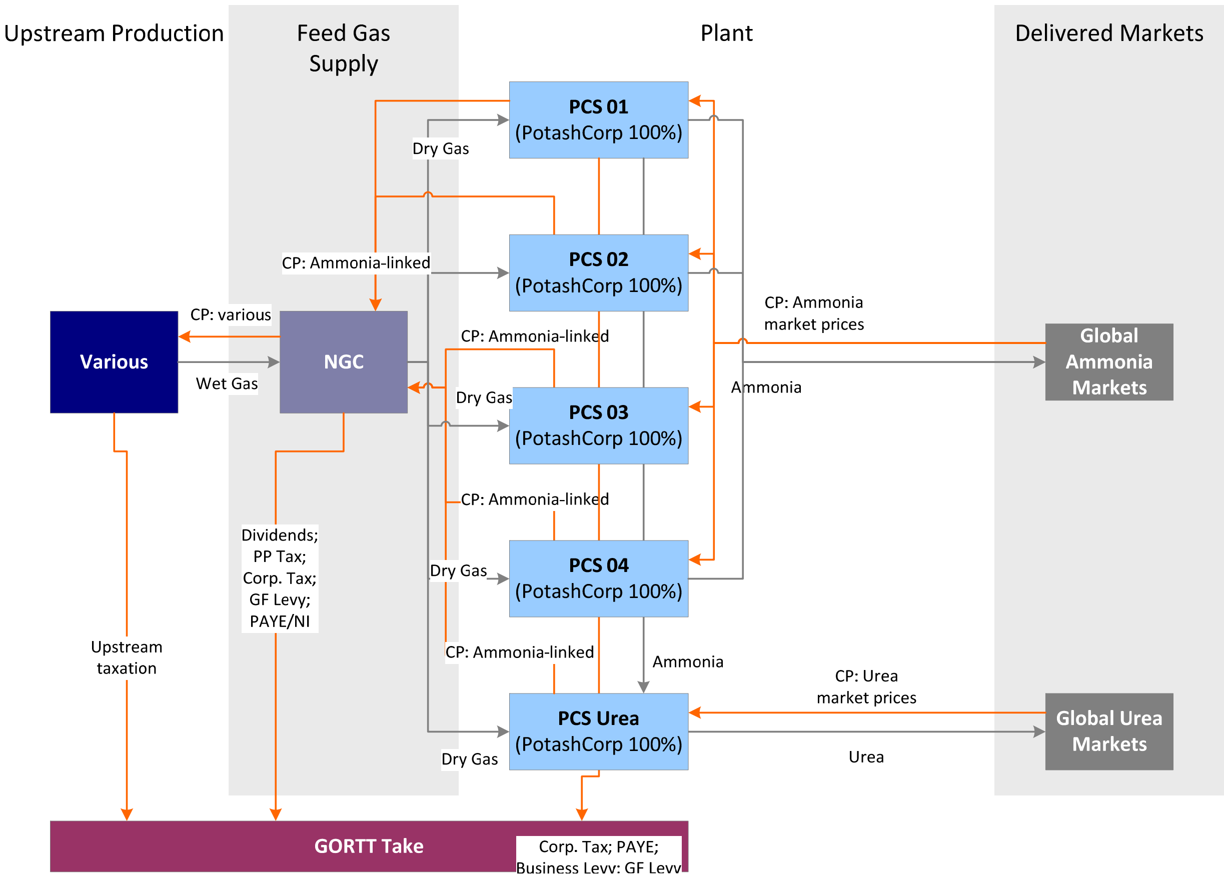
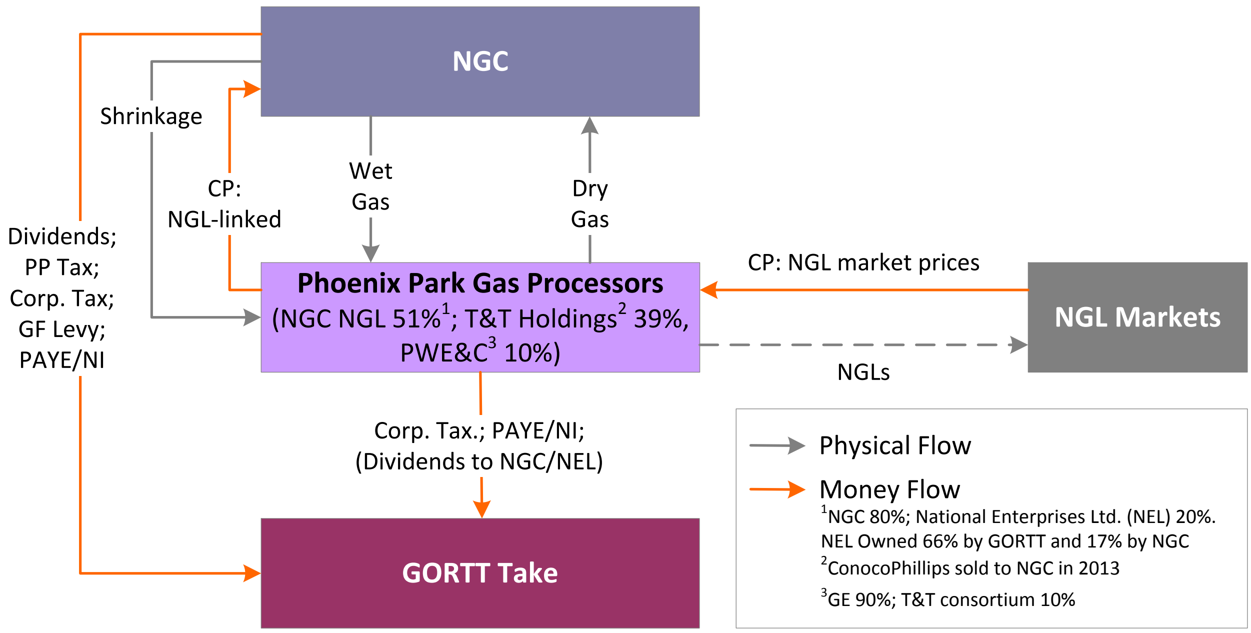


Figure I-3 PCS Physical / Financial Flows



I.2.3 NGLs

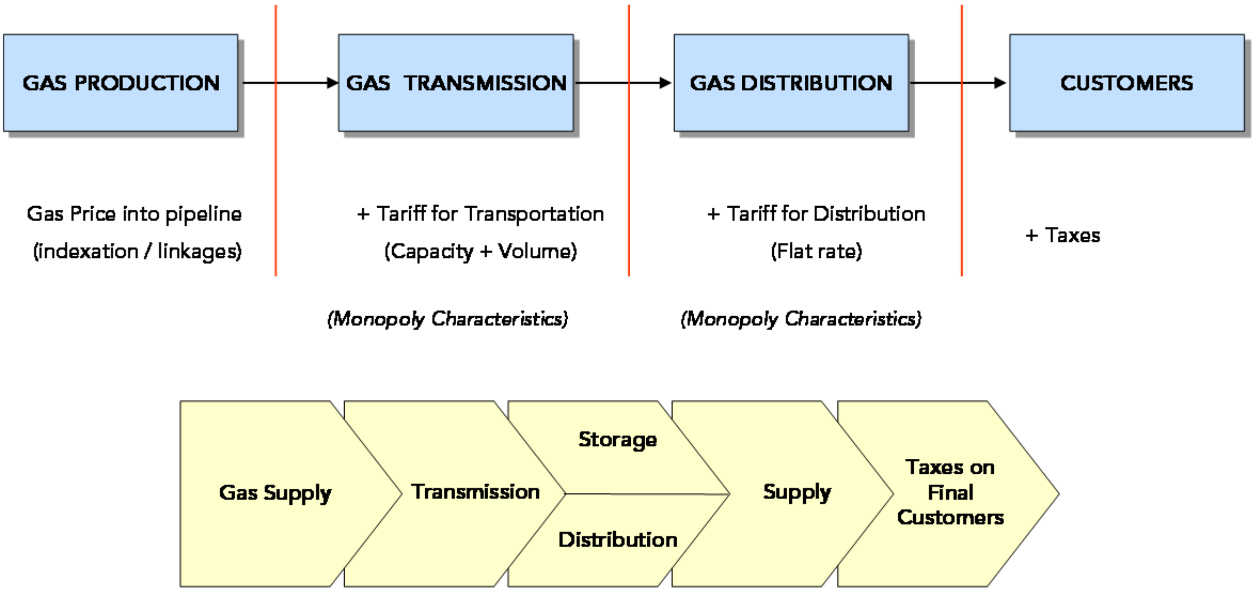
Figure I-4 PPGPL Physical / Financial Flows



J.1 THE GAS VALUE CHAIN

The gas value chain has four structural elements; upstream production and processing of the gas to a pipeline specification, the long distance transportation of gas in high volume through a pipeline transmission system, the low volume local supply of gas through a distribution system to end customers.

Figure J-1 The Physical Gas Value Chain



The different elements of the chain have different economic characteristics:

- Natural gas production consists of the complex series of operations necessary to deliver natural gas to the wellhead, such as exploration, drilling, production, and gathering. The natural gas produced by individual wellheads is gathered and delivered to a location such as a terminal, where it is injected into a pipeline. Gathering is usually considered part of production, because producers often own and operate gathering pipelines. Production is characterized by multiproduct scale economies across the whole set of operations at the company level, but these scale economies typically are not large enough to eliminate competition at the industry level. Producers must incur substantial fixed start-up costs, much of it sunk costs, first in the acquisition of drilling rights and technology and then in exploration and drilling. Only then can a producer start producing natural gas. It is more feasible for one firm to carry out both exploration and drilling than to separate these tasks because of the uncertainty in searching for natural gas. As a result, the optimal size of a production firm is large, though still small relative to the natural gas market.
- Natural gas transportation is the set of operations to deliver natural gas from a producer to consumer markets through high-pressure pipelines. The transportation segment is characterized by natural monopoly because of the large economies of scale resulting from the high fixed costs of pipeline construction. Most of the fixed costs are sunk because a pipeline has limited alternative uses. Pipeline variable operating costs are relatively low. There are also economies of scale associated with the multiproduct characteristics of

transportation services. A pipeline company can use the same pipeline system to offer transportation services that differ in time, location, and other dimensions (such as the calorific value of natural gas and the intake and offtake pressure of the pipeline). As a result, only one pipeline company can typically operate in the transportation segment, although large markets can accommodate several pipeline companies. (The notable exceptions are the United States and Canada where the market is sufficiently large that competing transmission pipelines have been developed, although even in these countries the local distribution systems are monopoly suppliers.

- Natural gas distribution consists of the operations necessary to deliver natural gas to the end users, including low-pressure pipeline transportation, supply of natural gas, metering, and construction of customer sites. Distribution is characterized by natural monopoly because of economies of scale in transportation operations. Additionally, there are economies of scope among various operations of a distribution company, because they are performed by the same distribution pipeline system. Distribution companies typically enjoy exclusivity in natural gas supply in their region, but an increasing number of countries have instituted open access in distribution.

The commercial element of the gas value chain is natural gas marketing and trading where intermediaries participate in the market to create a wholesale market, and supply to resale in the retail market. The gas marketing and trading and supply business is typically a very competitive segment because of the limited scale economies. Traders and marketers need little up-front investment to start operations— a trader needs only a desk, a computer, and a telephone to contact customers and make deals. As a result, the optimal size of a gas trader or supplier is small relative to the gas market.

J.1.1 Gas Markets are Different

Gas markets are different from other commodity markets. Gas can be bought and sold like any other commodity but its transportation is in most cases a natural monopoly. It is generally inefficient to build competing networks, in particular for local distribution, because of economies of scale. Therefore the supply of gas to consumers in most cases involves some degree of monopoly. Government has a responsibility to regulate natural monopolies in order to prevent market abuse.

Gas prices in competitive markets may diverge considerably in the short and long term. In the short term prices will mostly be determined by the marginal value of gas in the end user markets. Storage may provide sellers an opportunity to hold gas off the market when end user prices/demand are low. Prices will tend to fluctuate between short run marginal costs (variable operating costs) and long run marginal costs, which include a large element of upfront capital expenditure. In temperate zones where the domestic energy market is significant end user demand for gas is often strongly correlated to the weather.

Many gas customers are captive as they have no short term alternative to using gas, so overall demand for gas is inelastic in the short term. Captive customers require uninterrupted supply at all times, and demand seasonality can impose additional supply costs as production and transport infrastructure must be sized for peak demand. Non-captive customers with the ability to switch fuel or plant may be supplied under interruptible contracts allowing supply to be diverted to captive customers at times of high demand/price.

J.1.2 Structure of Natural Gas Markets

Historically the gas companies setting up greenfield gas supply and transmission businesses have typically been state owned or controlled enterprises and have generally been granted extensive monopoly rights over transportation and supply within a given area or country. They have not been required to offer pipeline access to third parties and indeed in the early stages of development there would usually be no parties to which capacity could be offered. The case for a monopolistic regulatory structure in the early stages of development of the industry is based upon a number of factors:

- The development of a greenfield gas network is seen as a high risk enterprise with much uncertainty in regard to capital costs and the speed of market development. Private investors are reluctant to undertake such investments and such investment requires state participation.
- The large initial investment financing typically relies upon assurances of future pipeline usage. Typically this is provided by a combination of long term contracts with suppliers and large buyers and monopoly rights over supply to customers in a given area – often the entire country.
- A monopoly gas transportation/supply company could extract monopoly rent if it is able to set prices in relation to competing fuel. A state owned company would act at the behest of the Government in regard to pricing. Indeed Governments seeking to promote the development of gas infrastructure from scratch may use energy taxation to give gas a competitive advantage over other fuels.

As a result the early years of a gas industry tend to feature strong vertical integration with the incumbent company responsible for transportation of gas and supply to the end consumer.

Over the last several decades new structural models of the natural gas industry have developed. Probably the most significant structural changes have been the introduction of open access - opening the pipeline transportation segment to third-party transportation, and unbundling -separating natural gas supply from pipeline transportation.

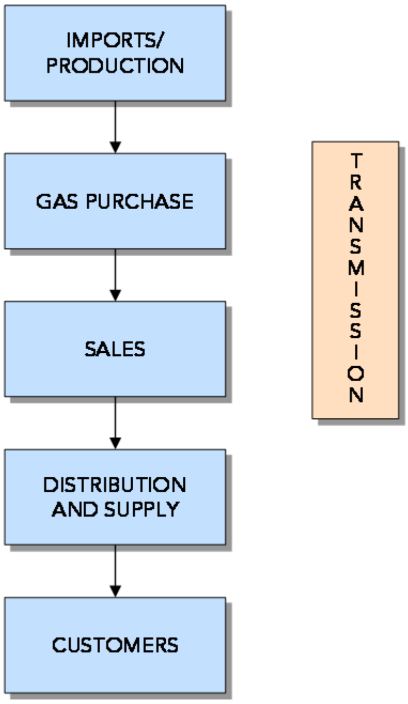
The deregulation and restructuring of the natural gas industry in many industrial and developing countries has led to the development of new markets that have altered the way the industry operates. As countries have deregulated prices and lowered entry barriers in the industry, many new participants have emerged, promoting competition in the newly created markets. The increased competition has benefited all participants in the natural gas industry - through more efficient pricing and greater choice of natural gas contracts.

It is now possible to discern four distinct structural models of the natural gas industry around the world. The traditional model of a vertically integrated industry has increasingly been replaced by structures that decentralize the industry along horizontal and vertical lines. These structures introduce greater competition and new models of interaction among market participants.

J.1.2.1 Vertical Integration

A vertically-integrated structure could be said to be the traditional structure of the natural gas industry, where production, pipeline transportation, and distribution are all performed by one company, an integrated gas utility. Typically, such a utility has an exclusive position in natural gas supply to end users, that is, in the retail market. An example of this structure is Gazprom, the Russian state owned gas company, which is engaged in all segments of the industry in that country, or Saudi Aramco in Saudi Arabia.

Figure J-2 Vertically Integrated Monopoly Structure



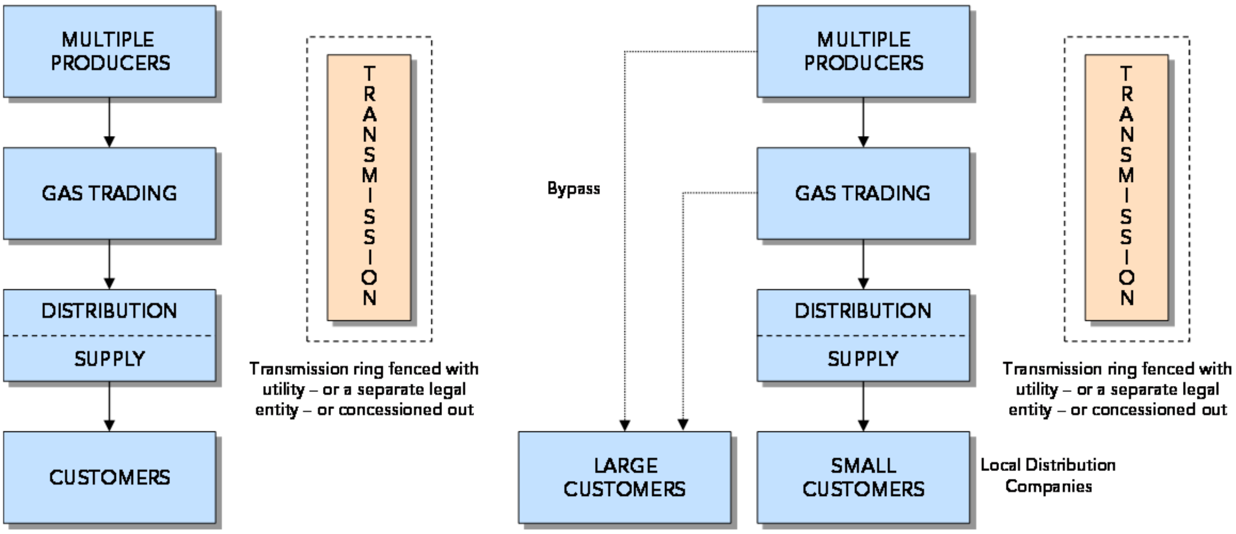
The integrated gas utility is usually heavily regulated because of its monopoly position in the retail market. The regulatory agency typically uses rate-of-return or price cap regulation to promote economic efficiency and restrict the utility's market power. However a vertically integrated utility typically lacks the flexibility required as the market grows and evolves to a more dynamic environment, and regulation is often insufficient to induce it to operate efficiently.

Governments seeking alternative industry configurations that would address these problems have identified several areas with good potential for cost savings: production, wholesale transactions, and retail transactions.

J.1.2.2 Competition in Natural Gas Production

This structure separates production from the rest of the industry and introduces competition among producers, resulting in more efficient production than in the vertically integrated structure. Producers sell natural gas to a gas utility, which then resells it to the end users. The transactions between the producers and the utility ultimately result in the development of a wholesale natural gas market, where natural gas is traded for further resale.

Figure J-3 Single Buyer Structure and Single Buyer with By-Pass Structure



In a variant of this model, single buyer with bypass, some producers may sell directly to some large customers bypassing the single buyer which continues to provide gas through the distribution system to small consumers. This variant provides larger consumers with more choice in supply from producers.

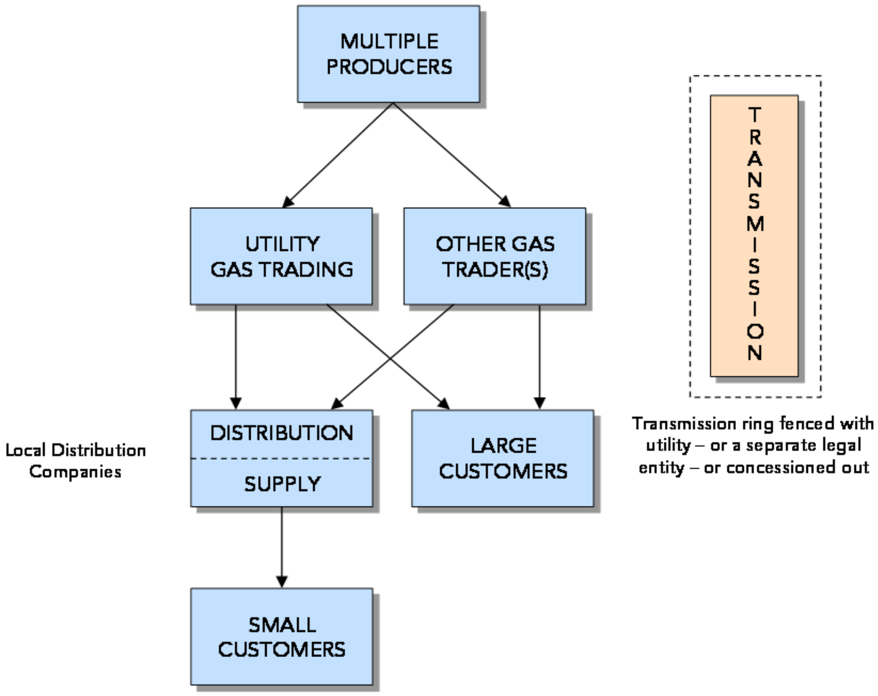
In this structure regulation is needed to restrict the market power of the gas utility relative to both the end users and the producers. End user prices are regulated in the same way as in the vertically integrated model. The price of gas sold by producers to the utility is also often regulated. Examples of this structure are Pertamina in Indonesia, KOGAS in South Korea or Petrobras in Brazil.

The optimal way to determine a purchase price is through competitive bidding, in which producers bid by price for a supply contract with the gas utility. A price determined through competition reflects the market value of natural gas far better than does a price set by a regulator. Monopolistic gas utilities can often prevent the pass-through of cost savings in production to end users because of distortive regulation or an ability to exercise market power. Governments therefore seek ways to open pipeline transportation and distribution to competition.

J.1.2.3 Open Access and Wholesale Competition

A further structural evolution introduces open access in pipeline transportation, opening the segment to third-party transportation. In this structure a gas utility thus provides two kinds of service: Supplying natural gas to end users and supplying transportation services to eligible participants that purchase natural gas independently. Alternatively, a gas utility is separated vertically into a pipeline company and several distribution utilities, and they provide open access to their pipeline networks.

Figure J-4 Open Access & Wholesale Competition



The open access regime promotes efficiency in the wholesale gas market and benefits market participants. Producers benefit because open access dramatically increases the number of buyers, eliminating the monopsony problem in the single buyer model. Downstream industry participants, such as distribution utilities or large end users, benefit from direct access to the production segment and a greater choice in gas supply. The US or the gas markets of the EU are examples of this structure.

In this structure pipeline companies have to coordinate transportation of their own and third-party natural gas through the pipeline network. This coordination is typically achieved by introducing market mechanisms that optimize interactions among market participants and the operation of the pipeline system in deregulated natural gas markets. Transactions in the wholesale natural gas market are typically conducted on a bilateral basis, but increasing complexity calls for intermediation of these transactions.

The acquisition of natural gas and transportation services is often complex, and for some market participants it may be too difficult and costly. High transaction costs discourage smaller market participants from utilizing open access, despite opportunities for cost saving. This creates room for natural gas traders, which aggregate demand and supply for a number of smaller market participants by purchasing natural gas and transportation services on their behalf. Traders charge fees for intermediating transactions and minimize the costs of natural gas and transportation services by buying large quantities and arbitraging across available prices. Competition among traders is crucial to minimize their fees and to maximize the benefits for their clients. There are three important regulatory tasks in this structure: the protection of end users from the power of monopolistic gas utilities, the promotion of competition in the wholesale gas market, and restriction of the market power of pipeline companies relative to the users of their pipeline networks.

End user prices are usually regulated using rate-of-return or price gap regulation. Wholesale gas prices are deregulated if there is sufficient competition in the market. If competition is limited, regulators focus on removing entry barriers rather than on directly regulating prices, because regulating wholesale prices does not promote the development of competitive trading, in fact it can prevent it. The price of a transportation service, or the access price, is one of the most important factors in achieving competition and efficiency in the wholesale market as unregulated pipeline companies can charge excessive access prices or foreclose access to maintain their monopsony power.

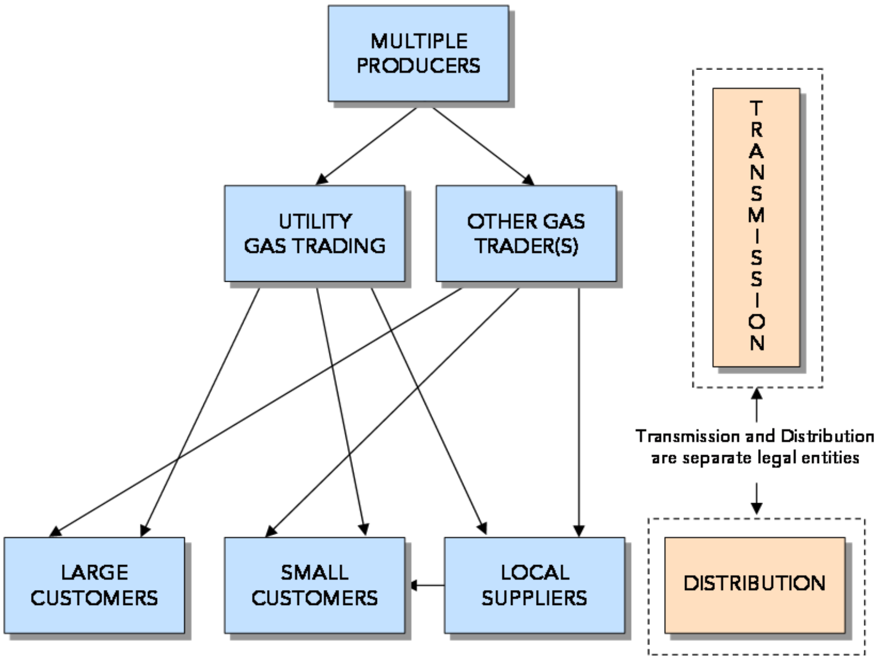
J.1.2.4 Unbundling and Retail Competition

The most extreme or disaggregated model features the separation of natural gas supply from pipeline transportation and distribution (unbundling) and full deregulation of natural gas markets. The main motivation for unbundling is to counter the ability of pipeline companies to restrict competition in the wholesale gas market through non price measures, such as offering low-quality transportation services.

Unbundling eliminates this distortion and creates a level playing field for all participants in the natural gas market. In addition, it facilitates the development of a large number of supply companies that purchase natural gas in the wholesale market, resell it downstream, and use the transportation services of pipeline and distribution companies. Competition among supply companies pushes down their resale mark ups and thus facilitates the pass-through of cost savings from the production segment to the end users.

The only gas market in the world that has evolved to this state is the UK.

Figure J-5 Open Access & Retail Competition



Increasing competition in and deregulation of the natural gas market eliminate the need for price regulation at the wholesale level and call for regulatory mechanisms that give gas companies more pricing flexibility at the retail level. Rate-of-return regulation greatly restricts pricing flexibility and so is less optimal in this structure than price cap regulation.

In this structure the natural gas market undergoes significant transformation to accommodate the variable requirements of market participants, which seek more flexible trading and contractual arrangements than the open access and wholesale model. Natural gas is increasingly traded through short term contracts to balance supply and demand in the short-term and give market participants the flexibility they need.

The development of a short-term, or spot, market promotes efficiency in the entire gas market. As a spot market becomes more liquid, the spot price moves toward the short-run marginal cost of gas, which reflects the market value of natural gas at the location of the spot market. Because prices are continuously determined in a liquid, competitive market, the pricing of natural gas becomes more efficient. Market participants use spot prices as a reference price in bilateral gas supply contracts, and so as a result, most natural gas is traded at spot prices.

J.1.3 Evolution of Natural Gas Markets

The structural changes that have been witnessed in gas markets have been relatively recent (i.e. since the 1980's) and while such changes have by no means been adopted globally, they have been widespread. The direction of travel has been in one direction, towards more market orientated structures[1]. We can identify a number of trends in the evolutionary process:

- A reduction in the role of the state in non-regulatory function in favour of the private sector.
- The introduction of open access to pipeline networks on a non-discriminatory basis.
- The unbundling of services; in particular the merchant function from that of transportation.
- The diminution of monopoly positions of market incumbents and the forcible reduction of their market power to boost competition.
- The development of independent regulatory bodies whose staff have expertise in technical, commercial and legal areas.

In almost all countries with a gas industry the local gas sector has been developed by a government owned national gas company responsible development of a gas infrastructure (pipeline transmission and distribution systems, storage etc.) while acting as the sole buyer and seller of gas and system operator i.e. the vertically integrated model. We are now witnessing a reduction in state participation with Governments divesting production assets and focussing on corporate governance and regulatory oversight.

The development of natural gas markets around the world away from this model has been led by the countries of North America and Europe and been taken up by a number of other countries to a greater or lesser extent. The drivers of change have been essentially threefold:

1) To improve the efficiency of the gas market. Governments, and in the case of Europe the EU, have sought to improve market efficiency and bring down costs and prices by stimulating competition in domestic markets by reducing the power of incumbents and opening up access to infrastructure and thus reducing the barrier to entry for new players.

2) To reduce the Government involvement in the sector: Government's traditional control of gas companies and intervention in their operations and investment decisions often led to distorted prices, inefficient operation, and deteriorating infrastructure. Reforms have aimed at limiting government's role in the industry's day to- day operations and establishing an effective regulatory framework under which market forces would balance demand and supply in segments of the industry where competition is feasible, and only those segments where competition is not feasible would remain subject to economic regulation.

[1] The move toward market based decision making and resource allocation is not just a gas market phenomenon. It has been witnessed across the utility sector; water, power, telecommunications etc. where natural monopolies exist with underlying infrastructure.

3) To introduce private investment into the sector and reduce the burden of funding upon the Government, freeing up state funds for investment into essential areas of the economy such education health and infrastructure.

Since 1984 the United States has separated natural gas supply from interstate pipeline transportation, deregulated natural gas production and the wholesale market, and introduced competition in interstate pipeline transportation. The United Kingdom partially opened its natural gas market to competition in 1986, when the government privatized British Gas, and subsequently continued deregulation by further opening the wholesale natural gas market and fully separated pipeline transportation and introduced competition in the retail market. By the turn of the last century the United Kingdom should have the most competitive natural gas industry in the world.

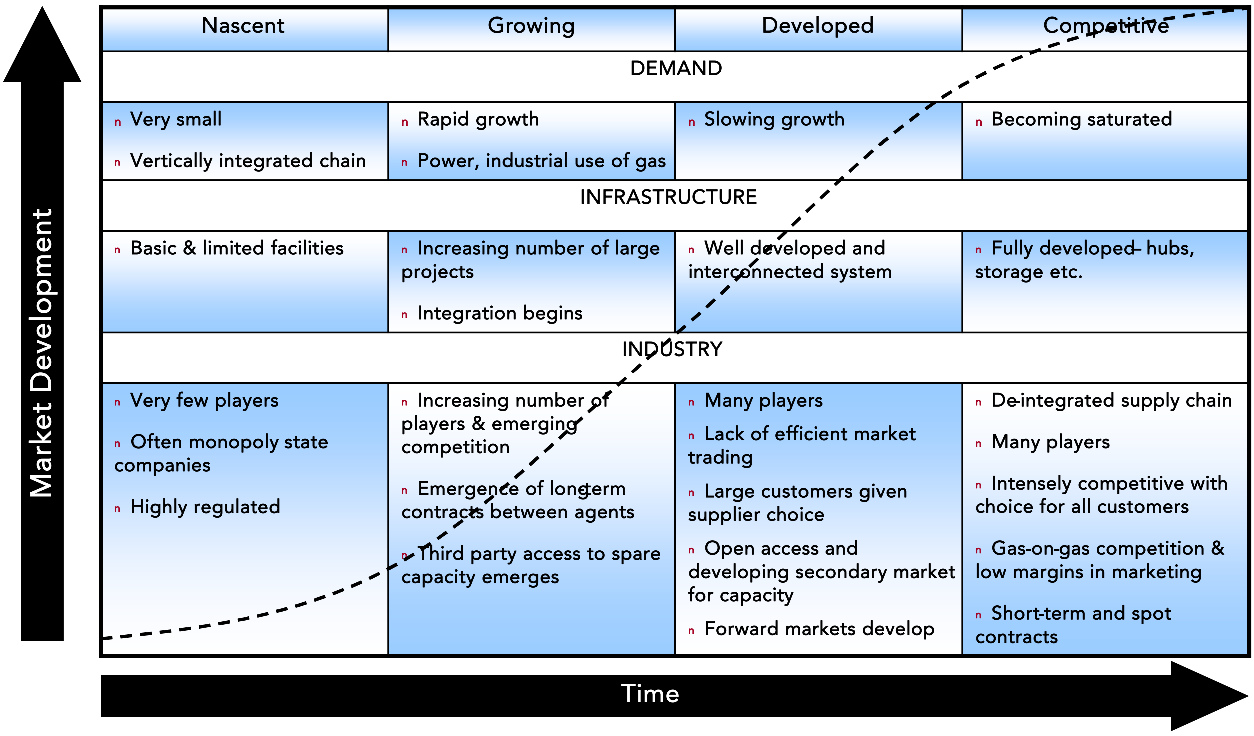
However this is not a trend limited to western economies and countries with gas markets at a comparable stage of development as T&T have also embraced structural change. Argentina undertook a radical reform of its gas industry in 1992, when it separated and then privatized natural gas production, transportation, and distribution. Distribution companies and large end users can now purchase natural gas directly from producers, bypassing the resale units of pipeline transportation companies. Mexico opened its natural gas market to competition in 1993 and is currently undergoing another overhaul to increase competition in the upstream and downstream sectors. In fact Mexico is undertaking a complete transformation of its energy sector. In December 2013, Mexico's Congress approved a series of constitutional amendments that will end the 75-year state oil monopoly and open oil and gas exploration and production to foreign investment. In August 2014, Mexico's Congress approved secondary legislation implementing the necessary reforms for the liberalization of the energy sector (the Secondary Legislation). The Government is seeking private investment to boost oil and gas exploration and production, which have been in decline for the past 10 years. In particular, the government hopes that private investors will assist the state-owned petroleum company PEMEX to exploit future fields, including Mexico's promising shale oil and gas fields and its deep-water oil resources. Currently, the gas transport infrastructure is controlled mostly by PEMEX and the Comisión Federal de Electricidad (CFE) and a few private companies. To incentivize domestic production, Mexico will improve the transport system for natural gas. To improve competition, management of the integrated system of gas transportation and storage will be handed over to the newly created National Natural Gas Control Center (CENAGAS). Both PEMEX and the CFE will transfer their existing gas transport and storage assets and contracts to CENAGAS. CENAGAS will tender gas infrastructure projects to private and state-owned companies.

A government that wants to reform the natural gas industry faces a complex task. It needs to assess the viability of competition in the industry as a whole and in its segments, identifying those with natural monopoly characteristics. And it needs to formulate optimal regulatory policies and introduce mechanisms to support efficient interactions between regulated and deregulated segments of the industry.

J.1.4 Observations on Gas Market Restructuring

Restructuring has been developed furthest in the most market orientated economies, the UK and the US, pushed by a Governments seeking to improve the functioning of the market and increase competition. In the case of the UK the initial trigger was the divestment of state owned assets to the private sector. In Western Europe the main driver has been the desire of the European Union to enhance the security of supply through the stimulation of cross-border competition and introducing economic efficiency through competition.

Figure J-6 Evolution of Natural Gas Markets



The primary feature of restructured markets is the unbundling of traditionally vertically integrated market structures and the segmentation ion of the various market functions i.e. transmission, distribution, trading etc. This has required the creation and or enhancement of the regulatory function to oversee the natural monopolies inherent in the transmission and distribution pipeline systems.

The extent to which restructuring can be practically undertaken is a function not just of the political philosophy of governments but also the underlying market size and characteristics, and the prevailing economic situation. It is evident that one size does not fit all markets when it comes to structure. Truly competitive market structures can only be introduced into mature systems with a depth of market. Developing markets need long term contracts and dedicated capacity in infrastructure to support financing.

The viability of competition in a gas industry is determined by three factors:

- Technology - Technology determines economies of scale and scope and thus a firm's optimal (or minimum efficient) size.
- The size of the market - The size of a market determines how many firms can efficiently compete in it
- Entry barriers - Entry barriers determine whether an additional firm can enter the market, if the opportunity to do so exists

These three underlying factors determine the efficient configuration of the industry. Any assessment also has to consider the potential for changes in the underlying factors to the environment in which the industry participants operate. Technological development, uncertainty about supply and demand, and regulatory changes all influence the viability of competition in the industry in the long run.

The viability of competition must be assessed separately for each segment of the natural gas industry, because participants use different technologies in each segment. If competition is viable in natural gas production and trade and supply, prices and entry should be deregulated to promote efficient markets. If producers, traders, and suppliers are restricted in their ability to set prices or enter the market, some participants will acquire enough market power to sustain high prices. Without price arbitrage or the threat of new entrants to discipline incumbent companies, other market participants incur welfare losses.

The economic efficiency goal of regulation implies that the regulated prices of pipeline transportation or distribution services must reflect their economic costs and maximize social welfare. This does not necessarily mean that regulators must always set prices administratively. Instead, whenever possible, regulators should adopt pricing concepts that give utilities incentives to set optimal prices for transportation and distribution services. Such concepts as peak-load pricing, Ramsey pricing, and nonlinear pricing promote efficient pricing and benefit all industry participants.

J.1.5 Oversight of the Natural Gas Sector

There are three main approaches for the assignment of powers to regulate and oversee the sector:

- Separation-of-powers model: an independent technocratic agency has regulatory powers.
- Ministry-dominated model: the petroleum ministry or an equivalent executive body is charged with regulation and oversight.
- NOC-dominated model: the NOC has de jure or de facto responsibility for day-to-day regulation, sometimes including the power to award exploration/production licenses.

Contemporary economic thought has generally advocated the separation of-powers model as the most likely to bring about clarity in roles and responsibilities by separating the licensing/monitoring/regulatory body from the policy-maker. In so doing a government promotes the development of technocratic skills and encourages its neutrality by keeping the agency at arm's length. As the agency has no commercial interest in licenses, it reduces the risk of conflict of interest, ensuring that the priorities of the state, not the company, are driving oversight.

However, in a low-capacity context, governments may choose to concentrate resources within one institution, usually the ministry of energy or the NOC. This set-up may provide countries with low institutional and human capacity a way to build sector capacity and exert effective national control over the sector more quickly. NOCs are able to establish their own hiring procedures, training and benefits packages and meritocratic promotion procedures and, in a number of cases, this has enabled NOCs to make employment in the company more lucrative than is the case within the civil service.

There are risks associated with the concentration of responsibilities. In cases of weak capacity in particular, this poses risks in terms of accountability processes. Governments face the dilemma of concentrating responsibilities and resources in order to build capacity quickly within a single institution, or separating functions to build the foundations for good governance.

J.1.5.1 Economic Regulation

The natural monopoly in pipeline transportation and distribution calls for economic regulation to prevent the incumbent utility from exercising its market power. The main goal of economic regulation is to promote economic efficiency. Regulators often pursue additional goals, such as fairness or transparency, but these complement rather than substitute for the economic efficiency goal. Economic regulation employs various mechanisms to regulate the prices of goods and services, the performance of regulated firms, and market entry. Typically pricing is set by one of two well-known and widely used regulatory mechanisms:

- Rate of return regulation: Rate-of return regulation allows the regulated utility to set rates for natural gas such that it earns no more than a predetermined rate of return on its capital. The regulator approves the rates and the size of the capital base that is used for calculating rate of return, and prohibits entry in the utility's line of business. The targeted rate of return is typically set equal to the rate of return on capital facing the same risk as the utility's capital. The utility is assured of earning the targeted rate of return because the regulator typically allows a pass-through of cost increases to the end user rates.
- Price cap regulation: Price cap regulation sets the maximum price that a natural gas utility can charge its customers for a certain period. After this time, typically three to five years, the regulator reviews the welfare impact of the price cap and determines a new price cap. This mechanism is intended to drive the utility to make efficiency improvements as that will be the primary means of increasing its profitability over the regulation period.

Appendix K Legislation & Regulation

The legal requirements of the Natural Gas Industry are met through a hierarchy of legislation. It is helpful to survey the following sources in determining whether the legislative framework is adequate:

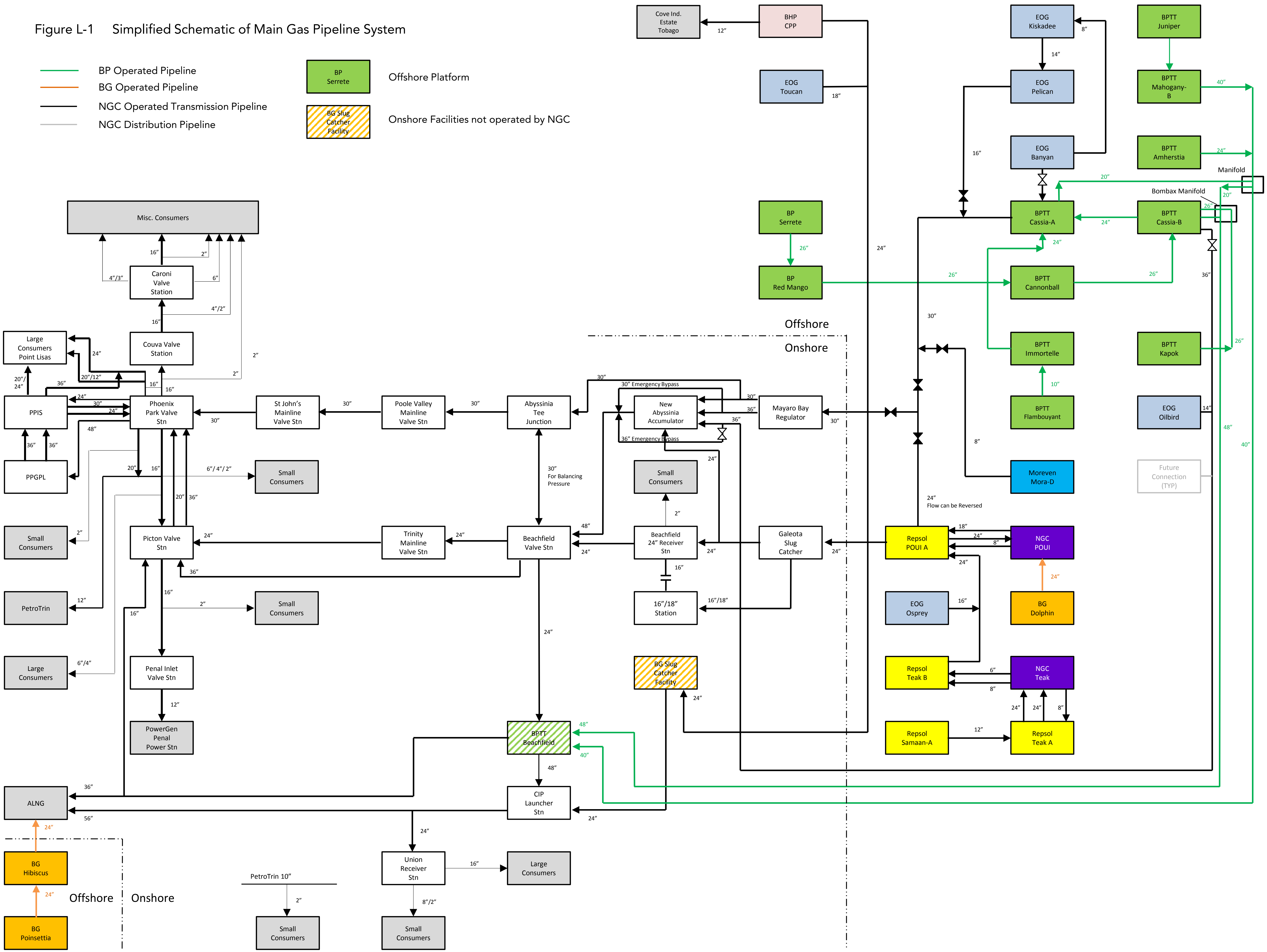
- National Constitution – Articles dealing with the appropriation of resource ownership to the State, authority for execution and ratification of contracts, restraints on foreign ownership and compensation for the expropriation of private property. The Constitution may also contain articles that give the President or other governmental officials the authority to execute contracts for the exploration and development of petroleum resources by foreign corporations.
- International Treaties and Conventions – Embody intergovernmental commitments in respect of foreign investment, transit, trade, pollution, taxation and regulation of cross-border trade. In the case of a potential conflict with domestic legislation, the provisions of a treaty or convention will take precedence.
- Petroleum Law – Statutes controlling the procedures for allocation and administration licenses and production sharing contracts, approval of work programs and development plans, participation of the national oil company, selection of service Contractors, surface access rights, pipeline right-of-way, prevention of resource waste and penalties for non-compliance. Most petroleum laws focus upon upstream petroleum operations and do not address issues regarding transportation and trading.
- Gas Law – Statutes controlling the marketing and transportation of natural gas, primarily within the domestic market. Of particular importance are provisions regarding regulation of prices for sales and transportation tariffs and third party access to pipeline systems. Typically, these issues are administered by an independent regulatory body.
- Petroleum Regulations – Rules implementing the Petroleum Law regarding the conduct of petroleum operations, technical standards, work place safety, preventing pollution, reporting and inspections. These regulations will be administered either by a political subdivision (ministry, department, agency or authority) or the national oil company.
- Model Contracts – The terms and conditions of production sharing or state participation, scope of petroleum operations, minimum work obligations, relinquishment of exploration areas, determination of a commercial discovery, right to take production in-kind, local content obligations, cost recovery and accounting procedures. The conditions of a model contract may not be open to negotiation.
- Environmental Law – Statutes and regulations controlling issuance of discharge permits, oil spill reporting and decommissioning of surface facilities. In many countries, development plans cannot be approved until an environmental impact assessment has been performed that includes the opportunity for public consultation.
- Petroleum Tax Code – Provisions concerning the level of assessment, eligible deductions, tax indemnities or holidays, withholding obligations for service Contractors, retention of records, procedures for filing returns and issuance of receipts for payment by foreign corporations.
- National Tax Code – The tax rate on domestic and non-resident companies as well as excise and business turnover taxes, special levies on petroleum resources, employee withholding

obligations, audits and penalties. Special Provisions for the taxation of the Petroleum Industry incorporated in the general corporate tax law.

- Contract Law – Statutes and/or judicial precedents concerning the formation, execution and enforcement of contracts, particularly regarding the sales of goods. The law of some countries will recognise the use of a Deed of Covenant or Deed Poll as an alternative form of binding agreement.
- Competition Law – Statutes and administrative decisions concerning approval of mergers and acquisitions, anti-competitive conduct and prohibition of contracts or arrangements that restrict market competition and sanctions. Most competition laws focus on downstream transportation and trading.
- Foreign Investment Law - Statutes restricting foreign ownership of key industries or land as well as procedures for making application to the government for approvals. In some countries, official approval must be obtained either before or after the actual contract is executed.
- Dangerous Goods Law – Statutes and technical standards concerning the bulk storage, handling and conveyance of dangerous goods that have flammable or explosive properties. These laws focus on siting, design and prevention of explosions and fires.
- Labour Law – Statutes, regulations, industry awards governing compensation, work rules, visas and entry permits for expatriate personnel, workman compensation insurance and occupational health and safety.
- Customs Law – Statutes and regulations governing the import and re-export of exploration equipment and export of petroleum production. These exemptions may be incorporated in the Petroleum Law and coordination between the two statutes is important.
- Arbitration Act – Statutes and forum rules concerning the use of arbitration or other alternative dispute resolution procedures as a means for the settlement of disputes. The role of local courts in either staying arbitral proceedings or enforcing awards is particularly important.
- Decrees or Executive Orders – Orders issued by the head of state or Cabinet in Counsel, possibly under martial law. A key consideration is whether these orders can supersede or supplement statutes and regulations.
- Delegations of Authority – Directives by the head of state or minister responsible for petroleum resources that confers responsibility for negotiation, administration and regulation on departmental officials. Contracts and licenses should be awarded in a process that is transparent to the public.
- Codes of Practice – Advisory documents issued by the ministry or department responsible for the administration of the Petroleum Act as guidelines for acceptable practice in conducting petroleum operations or access to facilities. Codes should be based on best industry practice for that country.

Appendix L Gas Pipeline Infrastructure Schematic

Figure L-1 Simplified Schematic of Main Gas Pipeline System



M.1 CASE STUDIES OF LOCAL CONTENT POLICIES

M.1.1 Introduction

The development of industries in countries has been the subject of great controversy over several centuries. The prevailing school of thought that modern trade practices are based on, such as WTO etc, is that protectionism is harmful in the long term and costly to the consumers in that country. In the conventional view, competition is healthy and will lead to long term growth.

As highlighted Section 6.7.3.4 Impact of Globalisation of Industries, for most countries, the size of their oil and gas industry is insufficient to sustain a competitive industry that can supply every input the oil and gas industry needs. To be efficient, you need to be in the top 5 to 10 suppliers in a subsector and if your oil and gas industry is less than about 10% of the global oil and gas industry, then a country will not be able to sustain industries supplying every input needed if it only concentrates on supplying the domestic oil and gas industry. To be efficient, the supply industry needs access to the global market and therefore must be capable of competing globally. The issue is then, can the government assist companies in reaching the top tier of suppliers, as the alternative of a purely import substitution strategy will impose permanent costs on the oil and gas sector.

Ha-Joon Chang has summarised an alternative view to the classic WTO type approach[1]. Chang argues that the countries, such as the UK and USA, that strongly propose the free-trade point of view, in fact created their industrial base at a time when they used very dirigiste approach where the state takes strong influence over trade and industrial policies to protect domestic companies. He states that the argument that infant industries need protection from international competition was first developed by American thinkers like Alexander Hamilton in the early 1800's and that the USA only developed an enthusiasm for free trade after the Second World War.

The following section discusses some of the experiences of different countries in developing local content and applying these policy measures. Some of this material is taken from the case studies prepared by the World Bank and some from Shirley Neff's paper written for the Nigeria National Stakeholders Working Group and this has been added to from the experience of the Poten team who have first-hand experience of these issues in the countries cited.

M.1.2 United States of America

The USA is one of the few countries where the domestic oil and gas industry is large enough for a purely import substitution based strategy to be viable. More oil and gas service and supply companies are domiciled in the USA than any other country and it is estimated to account for around half of all such firms. The USA was one of the first countries to develop an oil industry and its oil service industry has kept at the forefront of technological development from the beginning. The Federal US Government has very little direct control or influence over the industry except for its ability to control the export of crude oil and natural gas.

There has never been a local content policy in the oil and gas industry in the USA, except for the transport of hydrocarbons on ships between American ports. The so called "Jones Act" requires that all cargo and passengers moving between US ports must be carried on vessels built in the USA and at least 75% owned

[1] Ha-Joon Chang, Kicking away the ladder; post-autistic economics review, issue no 15, 2002

by US citizens or companies and crewed by US nationals. There is a specific grandfathered exemption for the USA under WTO/GATT that was agreed when the USA joined the GATT in 1947. It is reviewed by the WTO every two years and remains in force. Some US politicians are seeking an extension of the law to force the new LNG projects that will soon export from the US to use Jones Act ships. At the end of the Second World War the USA had the largest and most efficient ship building industry in the World. Seventy years later in spite of the protection of the Jones Act, the US now has a shipbuilding industry that can build large oil tankers in only two yards and each has a capacity of one or two ships each year. Over the years, the US yards decided to build only ships for the Jones Act market, since competition was less and prices higher. This resulted in a downward spiral – fewer ships being built meant yards lacked the experience curve effects to build ships efficiently, so fewer ships were built. US politicians often state that American industry cannot compete against low cost Far East labour, but when compared with South Korea or Japan both of which have large shipbuilding industries, US wage rates are the same as Japan and only about 20% higher than South Korea. The two yards still able to build oil tankers buy the tanker design and detailed production plans from South Korean companies. Even with this technical help US workers require three times as many hours to build a ship as their South Korean counterpart (see chart below).

Figure I-1 Learning Curve Effects on Shipbuilding
(Source: NASSCO -one of two US yards capable of building oil tankers)

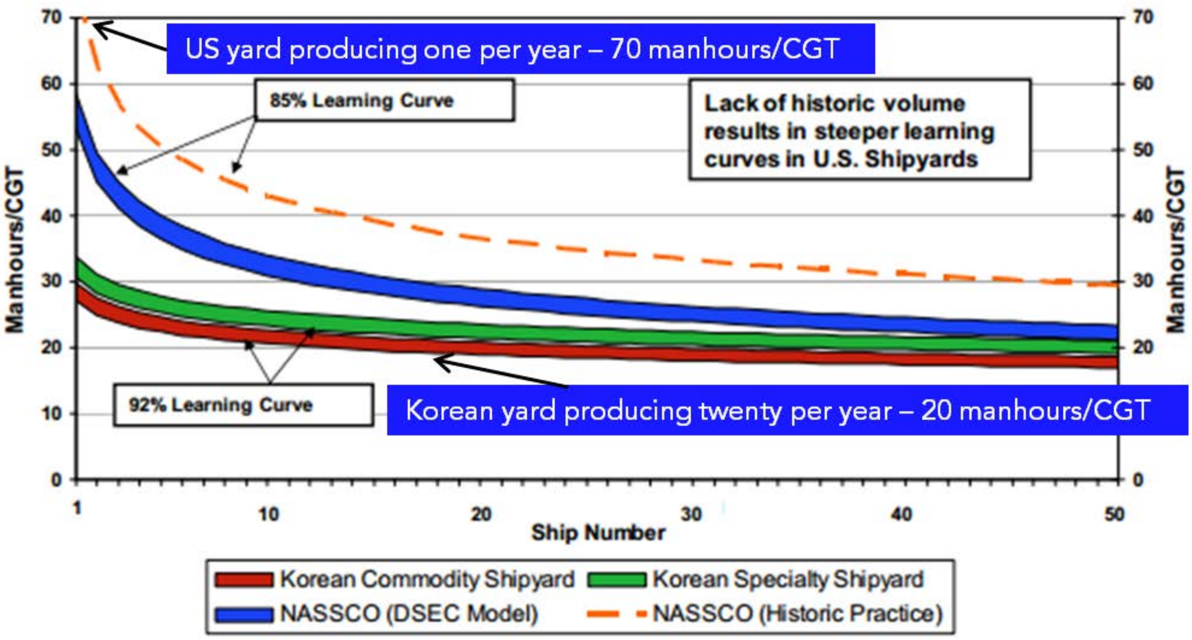


Fig A-1 shows the NASSCO's, one of the two remaining yards capable of building oil tankers, view on the situation. The graph shows that a US yard producing one tanker per year requires 70 manhours per GCT (Compensated Gross Tonne – a standardised measure of the shipbuilding that takes account of the complexity of the type of ship). A typical South Korean yard produces more than 20 tankers per year and requires only 20 manhours per GCT. The chart also shows that by using technology, drawings and supervision of their South Korean partners, the US yard is able to shift down to a lower learning curve and requires only around 55 manhours per GCT if only one tanker is built. Poten's Tanker Department tracks the cost of internationally built and Jones Act built tankers. We estimate that Jones Act ships cost between twice and four times the cost of an equivalent ship built in South Korea.

Apart from a few shuttle tankers operating in the Gulf of Mexico and some product carriers that move between refineries, the US did not need tankers and the burden of this extra cost for Jones Act tankers was not a major political issue.

The case study of the Jones Act does highlight how protectionism can fail. Far from allowing an industry to develop, the Jones Act presided over the disappearance of the US shipbuilding industry.

M.1.3United Kingdom and Norway – The North Sea Experience

Policies in the UK and Norway have been generally similar in their local content development. Until the discovery of the oil and gas in the North Sea, neither country had any significant domestic oil and gas production. The UK did have several major oil and gas companies with extensive international operations and a deep manufacturing base that supplied equipment internationally. Neither country imposed any direct or specific requirements on local content, but the governments did make it clear that they expected the oil and gas companies to give preference to local suppliers. In the UK's case, the government initially negotiated each concession for oil and gas production and this created the pressure to seek local suppliers.

To encourage the expansion of UK content, the government enacted three measures:

- Established a government agency, the Offshore Supplies Office to oversee the supplies industry. The OSO promoted new ventures, marketed the UK industry's ability and helped oil and gas companies find suppliers of equipment and support services.

- Introduced a standard auditing procedure for monitoring purchases. This later developed into a standardised process and code of practice for tendering that was negotiated with the UK Offshore Operators Association.

- Provided financial assistance to the UK oil and gas supplies industry.

By the mid- 1980's this policy was credited with reaching 86% local content, including 100% local content in maintenance and operations.

The European Union's rules on procurement that were introduced during the 1990's opened procurement in the Oil and Gas sector to all EU entities and eventually to other countries, including the USA. All tenders had to be published in the daily Official Journal of the European Union Supplement S. Local content then dropped back to around 60 to 70%, but by this time, the UK oil and gas supplies industry was already competitive and exporting its services.

Norway followed a similar pattern, with the government able to give preference in awarding licenses to companies that had a Norwegian involvement. In 1972, the Goods and Services Office was created with a similar mandate to the UK's OSO. Statoil was also created at the same time and, for example, the Statfjord field was licensed to Mobil on condition that the operatorship would transition to Statoil. Norway in this, and other fields, forced the international companies to train Norwegian oil companies and create a rapid transfer of knowledge and experience. In addition, the Government required oil companies to spend at least 50% of the R&D needed for Norwegian prospects in Norway. This helped create some of the Norwegian technical companies that now operate internationally. Today local content in Norway is estimated at approximately 50%. Although not a member of the European Union, as part of its treaty with the EU, Norway agreed to adhere to EU legislation including the requirement for full international competition in the oil and gas supplies sector. Statoil now operates as a commercial company without government support and Norway's state interests are managed for the state by a wholly owned government company, Petoro AS.

M.1.4Brazil

Oil was first discovered in Brazil in 1864, but commercial discoveries date from 1939. In 1953, Petrobras was created as the state owned company with monopoly rights on the upstream sector. At that time, local content was estimated at around 5%. Over the following years local content was heavily promoted and was estimated to reach 60% in 1960 and 80% in 1979. The move offshore then reduced this before recovering again to 91% by 1989. Data reported by Petrobras up to 2008 is showing 81% local content in goods and 78% in services. The local industry developed to support Petrobras contracts. After foreign companies were allowed to enter the upstream, the Government created a bidding system for blocks that is weighted in favour of companies committing to high local content. The World Bank Case Studies report that Brazilian oil and gas manufacturers struggled with high material and labour costs, high taxation and low productivity. They have been much less successful in exporting their goods and services.

Brazil also has a well-developed tertiary education sector that is heavily funded by government, aimed at producing technical and professionally qualified staff. However, primary and secondary education has not received the same level of funding and private schools have been very successful.

Brazil also has technical institutions able to create Brazilian technical standards. Technical standards, Normas Regulamentadoras, are established by the Brazilian Ministry of Labour and Employment and for example cover Pressure Vessels, Electrical Installations etc. Brazil has its own unique standard for electrical appliance plugs and sockets but does not have a single standard supply voltage (127v in some areas and 220v in others). These standards are also a barrier to foreign competition and protect domestic industry.

Brazil also has an extensive reporting system for recording local content spending that oil companies must comply with.

There is no doubt that the Brazilian oil and gas sector has been extraordinarily successful in creating an industry supplying the domestic industry. However, Petrobras consistently fails to hit its production targets and has blamed this on high costs and delays from domestic suppliers. The former CEO of Petrobras is quoted as reporting that the cost of an oil tanker built in Brazil was double that purchased from China. In interviews on another project in Brazil, Poten discovered that upstream companies onshore there were finding that the cost of a directionally drilled well was nine times that of their most efficient onshore operation in the USA. Petrobras is currently being investigated in the largest corruption case in Brazilian history. It is alleged that in exchange for placing contracts with Brazilian contractors, very large bribes were paid, including an alleged 3% commission on contracts that was channelled to political parties.

M.1.5Nigeria

Local content policy has been extensively discussed and developed over the last fifty years in Nigeria. In the 2000's, the Nigerian government believed that this situation needed attention. In Shirley Neff's paper, she mentions that estimates of local content in oil and gas expenditures ranged from 5%, expounded by the Government to 15% from industry participants. Data to substantiate these estimates was not given. Early attempts to encourage local content were driven by the state oil company Nigerian National Petroleum Corporation (NNPC). At the start of the decade, almost all activity in the oil and gas sector was undertaken by the Joint Ventures which NNPC was in theory controlling; in reality, the foreign partners, such as Shell provided most of the managerial and technical inputs. NNPC did impose local content rules on the JV's but these were mainly of the type that if local companies could produce at acceptable quality and price, then they should not be discriminated against. The perception in the Nigerian government was that the policy was failing and that Nigerian local content was too low.

Many international service companies operate in Nigeria. In interviews carried out in the early 2000’s by Poten team members they all reported a high degree of Nigerianisation of their in-country capability but all said that it was very difficult to persuade Nigerians to move to head office abroad and then up the career ladder. There was the natural reluctance due to family ties but also the financial rewards were higher to stay in Nigeria. This was due to Nigerian senior staff pay and benefits packages having been driven up by powerful unions to ensure they were equal to those paid to expatriate workers in Nigeria, i.e. for many of these companies, their Nigerian staff were receiving expatriate level rent, school fees and “home” leave allowances, plus very high cash per diem subsistence allowances when travelling overseas. This equalisation of benefits was part of the “local content” policy, i.e. expatriate staff could not be paid better than local staff. All the service companies and many of the IOCs reported that this difficulty of promoting Nigerian staff meant that it was difficult for Nigerians to gain the international experience they needed to be fully represented at higher levels in the organisation. This in turn resulted in a continuing need to rotate expatriates through Nigeria in order to ensure that expertise was transferred to Nigeria and corporate standards maintained.

The Nigerian Oil and Gas Industry Content Development Act was passed in 2010 but as its contents were extensively discussed over the preceding five years, its impact on major projects predated 2010. The Act imposed ambitious targets for Nigerian Content. For example, Front End Engineering Design (FEED) and Detailed engineering on Onshore facilities must be 90% Nigerian man-hours and even LNG Plants must be 50% designed in country. To comply with these rules, LNG projects planned for Nigeria were budgeting to undertake the design work with one of the mainstream LNG contractors at their home office, offshore Nigeria, and then employ a Nigerian design contractor to work in parallel. The impact on the project cost estimates of the 2010 Law was to increase capital costs very significantly. While, the problems of the Nigerian LNG projects cannot be entirely ascribed to their high capital costs, the three most developed LNG projects, Nigeria LNG Train 7, Brass and OK LNG all struggled with high capital costs and none have achieved Final Investment Decision (FID). This was at a time when the global competition for reaching FID on an LNG project was in Australia, where labour constraints make projects costly to build. The impact of the 2010 Law appears to have been to make Nigeria an uncompetitive location to build new projects.

Anecdotally, the law also appears to have resulted in the international oil companies divesting their non-core assets in Nigeria and these are being acquired by smaller companies, many of them Nigerian. While this is a win for local participation, it is not clear yet if these companies intend to invest and be able to accommodate the law more successfully than an IOC or if they will just produce the existing assets without investing.

M.1.6Australia

Australia local content rules have five strands:

- Domestic gas – LNG projects may be obliged by the state government to sell a percentage of their gas production to the domestic market. However this policy does not appear to apply to all projects;
- Labour – Australia has strict immigration laws that make it difficult for oil and gas projects to import labour, except experienced professionals with higher degrees;

- Tenders for equipment and services are obliged to give preference to local suppliers only to the extent that they offer equal or better price, quality, delivery and service. Oil companies are required to ensure that local companies are assisted in bidding for contracts. ;

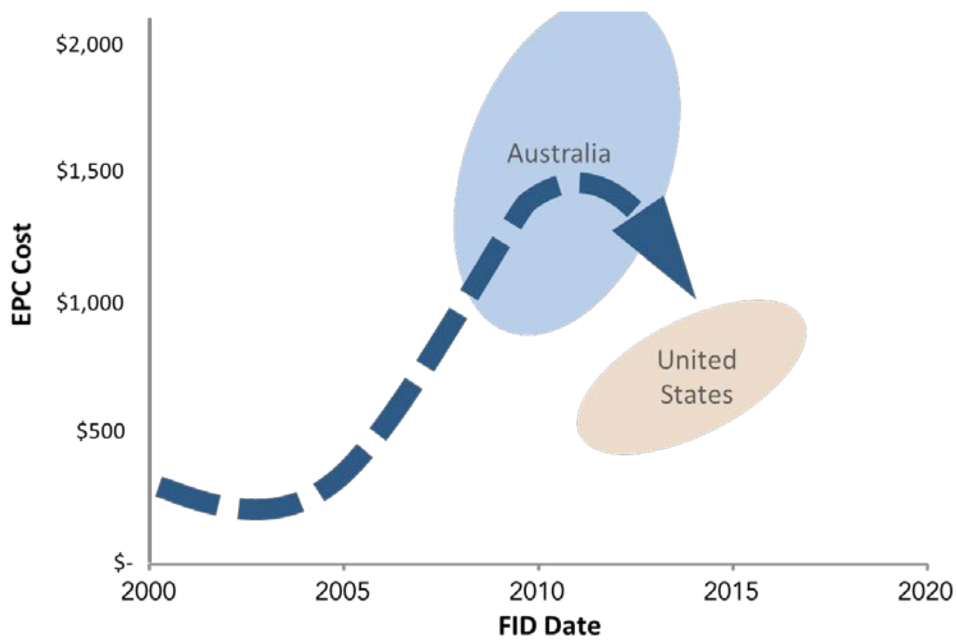
- States such as Western Australia have invested in infrastructure to support the oil and gas industry, e.g. the Australian Marine Complex, which is used by projects as a yard for staging etc.

- Oil and Gas companies must report quarterly on their expenditure on local suppliers and imported.

Australia is a relatively small country (population 23 million in 2013) and has a restricted pool of labour available to work in the oil and gas sector. The sector also competes for labour with Australia's large mining sector. Australian unions are very strong and most construction sites are governed by union agreements. In periods when the oil and gas and mining industries are busy, labour costs and fringe benefits are 'bid-up' and total construction costs become a multiple of other countries. Even where some imported labour is allowed in to work on Australian projects, it must be paid at Australian labour rates and receive the same conditions. To avoid these constraints on labour availability, projects resort to the use of large modules built in South East Asia or South Korea as a way of 'exporting' construction labour jobs. This further adds to costs and schedule delays. The recent LNG projects built in Australia, despite or because of the extensive use of modularisation are the most expensive ever (see chart).

Poten has seen various Australian Government estimates that approximately 50% of the capital cost of LNG plants is spent in Australia; the Gorgon project claims to have exceeded this. Given the high cost of labour and large proportion of total costs that comprises labour, we would judge this is quite possible. Australia has been fortunate in building these projects at a time when there was very little global competition for new LNG projects and Asian gas buyers had to pay what was necessary to justify the investment.

Figure I-2 Rise in LNG Liquefaction EPC costs in Australia



Australia does have an active promotional programme to assist companies willing to invest in Australia: Invest Australia . It is not specifically aimed at the oil and gas sector and today does not appear to include any tax or hard cash incentives. The current promotional activities for the oil and gas services sector include:

- Project Connect: An online service that lists project opportunities and connects Australian businesses with industry suppliers.
- Achilles Supply Base: A vendor pre-qualification and supplier management system for the oil and gas sector.
- Industry Capability Network: An independent networking organisation that connects local suppliers and service providers to meet the requirements of local projects.
- Industry Technology Facilitator: A not-for-profit organisation comprising members of the oil and gas industry that focuses on identifying technology needs, fostering innovation and facilitating the development and implementation of new technologies.

The Australian policy on labour laws has resulted in a high local value added, although most of this is construction manhours. It could be argued that the additional cost of building in Australia might have been captured by the Government rather than the construction workers if an international labour force had been permitted. Perhaps the policy has transferred income from the Government to a small group of workers to the detriment of the majority of Australians. Now that there are alternative new LNG projects, such as the US Gulf Coast projects, Australian projects are finding it very difficult to compete and no new Australian projects have taken FID since Ichthys LNG in January 2012; the labour restrictions make investment elsewhere more attractive.

M.1.7 Malaysia

Oil was first discovered in 1910 by Shell. Recently most developments have been offshore, with the first in 1968. Developments have now moved to deeper water. Malaysia has a large LNG complex at Bintulu and exports gas by pipeline to Thailand and Singapore. Petronas, the national oil company, was established in 1974 and pursued a strategy of partnering with major international oil companies both in Malaysia and overseas to gain experience. Today Petronas has partnerships in 32 countries with IOCs. MISC Berhad is a major ship owner and operator that is approximately 62% owned by Petronas. MISC owns or operates over 100 tankers including a large fleet of LNG tankers.

Local content rules are driven from the PSA terms, which require investors to:

- Minimize employment of foreign nationals – Petronas must approve recruitment
- Train Malay staff
- Commit monetary amount to training
- Offer on the job training to Petronas staff on request

Petronas has invested in four education and training institutions specialising in the oil and gas sector and sponsors over 1000 students each year.

Procurement of goods and services from overseas companies requires Petronas approval. Petronas has actively mentored other Malay firms how to bid for work. Malaysian Investment Development Authority provides fiscal incentives (e.g. five year tax holidays) to pioneer industries; these are particularly generous to high technology activities. The government also has programs in place to increase the efficiency of domestic fabricators for the oil and gas industry by encouraging consolidation, limiting new industrial licenses and using Petronas to increase the size of packages for tender. Petronas has two dedicated units devoted to managing local content issues.

The Malaysia Petroleum Resources Corporation (MPRC) was established in 2011 and is intended to have a staff of around 20. It aims to support the oil and gas services sector by encouraging efficiency and helping Malaysian firms in identifying opportunities in other countries and in encouraging foreign firms to establish bases in Malaysia. The Government aims to capture 15 to 50% of the Asia Pacific offshore market.

Malaysia is a member of WTO and has made commitments to liberalise trade in goods and services. However, its position has been to offer market access to foreign suppliers only in sectors where the domestic suppliers are ready to compete. So far, no cases or complaints have been raised against Malaysia's actions to protect its oil and gas services sectors.

Several multi-national companies have established operations in Malaysia. For example: Technip has a large design office there and Schlumberger established a manufacturing plant for marine and land seismic equipment.

M.1.8 Conclusions from the Theory and Case Studies

As noted by the World Bank researchers, the most disturbing aspect of all the local content actions taken by governments has been the absence of any evaluation of benefits of the policies and their costs. Most local content policies have been driven by political rather than economic arguments.

We believe that the economic theory of local content and the case studies highlight the consequences, some successful and some not, of some of the possible policy actions that a government might take:

- Exhortation to use local suppliers may be underestimated by many governments – oil and gas companies do care what local populations think. The companies believe that efforts to use local suppliers are the right thing to do and will be rewarded in future negotiations with the government. This appeared to have been effective in both the UK and Norway.

- Discovering a latent comparative advantage that can be developed with some protection or encouragement is a strategy that could repay the investment. The UK is a good example. The initial encouragement and promotional activities from the government allowed a sophisticated industrial base to re-orientate towards manufacture for the offshore oil and gas sectors. A workforce educated to a high level in English is an underestimated advantage – the oil and gas industry works in English – even in France.

- Efforts in making Oil and Gas companies report their levels of local content appear to have been very successful in creating pressure on them to increase their local content.

- Australia's performance highlights how hard it is to achieve high levels of local content in major project executed in country without burdening the project with excessive cost. The industry is so global that anything above 20% local content is an exceptional achievement.

- Compulsory use of local suppliers appears to result in the local supplier losing any ability to compete in the world market as they will concentrate on the domestic market where there is less competition. This adds cost to the industry that is served. The extreme example of this is the US ship building industry, which has completely lost its ability to compete and is reliant on technology transfers from South Korea to build even relatively simple oil tankers. Brazil also appears to fall into this category with the

- Imposition of costly local content rules on the industry without any adjustment in the fiscal take will make projects uneconomic. Oil and gas companies will invest elsewhere. The Nigerian LNG sector is an example of this effect. Once stringent local content laws were announced, no LNG project could achieve a capital cost low enough to be viable. Australia has demonstrated a similar phenomenon with no new LNG projects once there were alternatives in more favourable regimes, such as the USA.

- Malaysia offers the example of a country that, while protecting its industry to allow it to develop, is clear that the industry must be efficient and internationally competitive and win export business. Malaysia has been highly interventionist and has deliberately forced local companies to consolidate to compete internationally. A clear vision of an industry that exports goods and services appears to help drive to efficiency.

- Partnering with international firms and encouraging international firms to establish manufacturing or services facilities has been a successful strategy for countries as diverse as the UK (attracting mainly American companies) and Malaysia.

- Investment in education and training relevant to the industry appears to be necessary to the creation of a viable oil and gas services sector.

- Local content in terms or local value added or local employment appears to have advantages over a strategy that emphasises local ownership as it allows multinational companies to establish operations in country and this generates technology transfer. An emphasis on local ownership might place an over emphasis on the creation of “agents” that resell imported products or local companies that need to generate their own technology – a slow process anywhere.

- Few countries have an oil and gas industry large enough to support a complete range of support services and manufacturers. A nation has to pick the winners to encourage – these need to build on a comparative advantage. This might be because the local oil and gas industry needs a specific new expertise, such as ultra-deep water operations or might be built on an existing industrial base that served other industries.

Appendix N Lessons from Other Gas-Short Countries

N.1 NEW ZEALAND

N.1.1 Overview

New Zealand has a gas industry that was developed more or less contemporaneously with that of T&T, and indeed there are a number of parallels to T&T in New Zealand gas sector development, albeit on a much smaller scale. The gas industry began in New Zealand in 1970 with the development of the onshore Kapuni field, and transmission infrastructure running through the North Island from Auckland to Wellington serving local communities. In 1969 a much larger offshore Maui gas/condensate field was discovered, a giant field with reserves of ~4.5 Tcf. Maui gas deliveries began in 1979, and at their peak accounted for over 85% of total gas supply.

N.1.2 Gas Sector Structure

New Zealand has a conventional gas industry structure, with an upstream exploration and production sector, and a downstream sector comprising high pressure (transmission) and lower pressure (distribution) transportation, and wholesale and retail markets. Some large users, notably power stations, petrochemical producers, dairy factories and timber processing plants, are supplied directly from the high pressure transmission pipelines. Relatively small by international standards – but nonetheless significant in the New Zealand energy market context – the gas industry in New Zealand has a concentration of participants, many of them with interests at more than one level of the value chain. One participant, Todd Energy, has integrated activities from upstream exploration and production, through private pipeline ownership, to wholesale and retail sales, and, with the commissioning of its McKee electricity generation plant, is also a consumer. The two major gas transmission systems are operated by private companies subject to government regulation.

N.1.3 Gas Sector Development

The Maui discovery was transformational and offered far more gas than New Zealand needed for the then size of the domestic market. The development of the Maui field proceeded with the government in 1973 becoming a half owner (through an investment vehicle Offshore Mining Company Limited), meeting half the development costs and agreeing to purchase all Maui gas under take-or-pay arrangements. The contract was to run for 30 years, expiring in June 2009, and the intention was to supply new and proposed gas-fired electricity generators. However, these proposals represented more electricity generation than the country needed. Coincidentally, a substantial change in world oil market dynamics – a series of economically damaging price increases known as the 1970s 'oil shocks' – drove a significant change in the government's thinking. A new strategy, to use Maui gas to achieve economic growth and to reduce New Zealand's dependence on imported oil, led to a programme of government-sponsored 'Think Big' construction projects. They included a number of large gas-based developments - an ammonia-urea plant at Kapuni, a synthetic petrol (or gas-to gasoline) plant at Motunui (synfuel plant)[1], and a chemical methanol plant in the Waitara Valley (Petralgas plant).

In 1978, the government consolidated all of its then increasing direct interests in the oil and gas sector into a new company, the Petroleum Corporation of New Zealand Limited (Petrocorp) which subsequently expanded its interests to include ownership of the Kapuni ammonia/urea plant 3 through a subsidiary

[1] The Motunui plant opened in 1986, converting natural gas to methanol and the methanol to synthetic petrol using the Mobil methanol-to-gasoline (MTG) process. Operation of the plant demonstrated the first-of-a-kind application but the process became uneconomic in the late 1990s owing to falling oil prices and the plant switched to producing methanol for export.

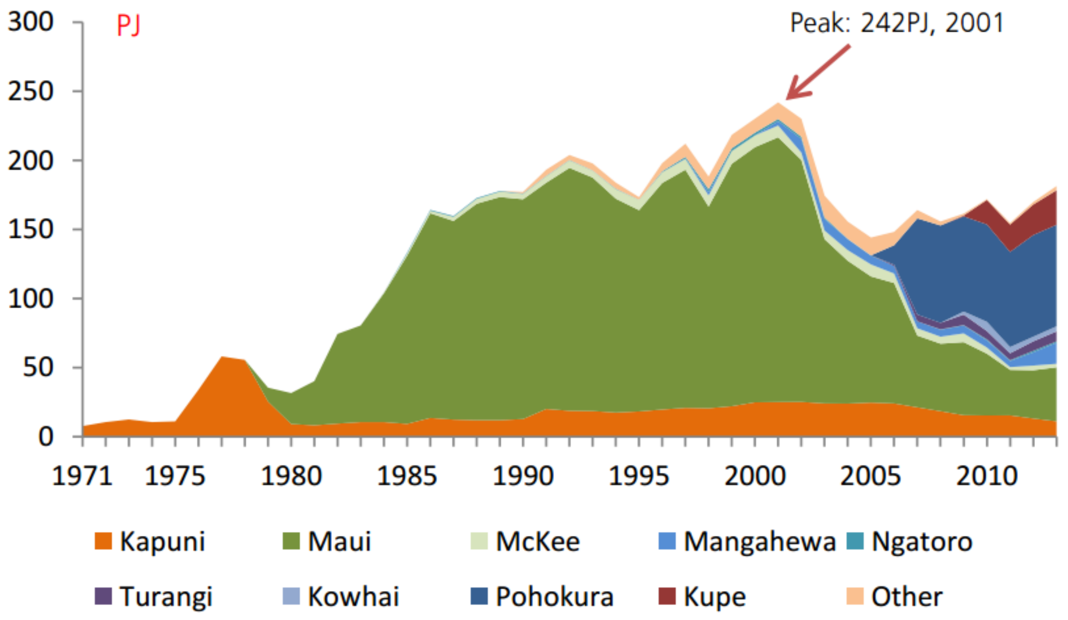
Petrochemical Corporation of New Zealand Limited (Petrochem), and a majority ownership interest in Petralgas Limited, which owned and operated the Petralgas plant. Subsequently as the gas industry expanded and matured, the government commenced a process of reducing its direct commercial involvement. In 1987, the government sold 30% of its interest in Petrocorp through the issue of new shares, resulting in Petrocorp briefly becoming listed on the New Zealand Stock Exchange.

The changing energy scene was also reflected in the evolution of the government's Maui contract arrangements. With the change in gas utilisation policy, after it became apparent that the forecasts for electricity demand were overstated and the government faced a substantial annual take-or-pay deficit, it committed its Maui gas entitlements to the development of the domestic market and to supplying the petrochemical plants. In 1990, following industry consolidation[2] and sales, three companies held six Maui contracts.

N.1.3.1 Maui Gas Dominated the New Zealand Energy Sector

The Maui development shaped the E&P sector and the wholesale gas market for 30 years. Gas supply was characterised by the use of long-term sales contracts with high annual take-or-pay commitments. Gas prices were bundled and buyers were able to store prepaid gas. The field was able to act as a swing producer to meet demand on the day.

Figure N-1 Net Natural Gas Production by Field 1971 - 2013
(Source: Gas Industry Company Limited)



The price for gas was set by the government and was a diminishing price in real terms as the escalator was the greater of either 50% of inflation, or inflation less 3%. The effective price cap on the gas meant that there was little change in prices essentially since the 1970s. However, the low prices led to suppressed incentives to explore, develop and produce gas from other fields and restricted the ability of other fuels to compete on price with Maui gas, resulting in a high investment in gas utilisation by large users taking advantage of low prices and plentiful supply.

[2] A key element of the consolidation was that Methanex acquired the Montunui and Waitara Valley methanol plants in 1993.

N.1.3.2 Maui Depletion Brings Significant Contractual Changes

The catalyst for major change in the gas sector came in 2003 when an independent reserves redetermination reported that the economically recoverable reserves from the Maui field were 3,562 PJ, which was considerably lower than industry expectation and gave raise to concerns over medium-term security of supply[3].

The Maui upstream companies (Shell, Todd and OMV), the government and the parties that held the final delivery rights to Maui gas (Vector, Methanex, and Contact) agreed to amend the terms of the contract, limiting the remaining amount of gas to be delivered under the contract price – which at the time was significantly below the international market price for gas – to 367 PJ. This was the volume of remaining Maui gas that the independent expert determined to be 'economically recoverable' from the Maui field. Any gas to be recovered in excess of this volume would be sold by Maui Development Limited (MDL) at the market price, thereby providing an incentive for further development of the field. Of any further gas recovered from the field, 40 PJ was reserved for Methanex[4]. Vector and Contact had a right of first refusal for the remaining additional gas (referred to as 'ROFR gas').

Diminishing Maui production brought fundamental change to the wholesale market. From abundant, cheap gas and a single dominant field, gas supply contract terms shortened and prices increased, resulting in some large users restricting or ceasing operations due to an inability to source gas at competitive prices and others switching to other fuels, including geothermal, and biomass.

The major loser from this process was Methanex which lost substantially all of its remaining contractual natural gas entitlements from the Maui field. Methanex's contractual entitlements to natural gas from the Maui field were subject to reduction if the Maui gas reserves were re-determined under the head contract between the owners of the Maui field and the government to a level below a specified quantity (essentially representing the aggregate of current contracted quantities). As a consequence Methanex closed the Monumui synfuel plant in December 2004 and idled the Waitara methanol plant.

N.1.4 Policy Developments

The revised end of life projections for the Maui field led the government to develop a policy that made significant changes to the gas supply arrangements in the country, recognising that production from an increasing number of smaller fields would require more sophisticated marketing arrangements.

In March 2003, the Minister of Energy issued a Gas Policy Statement (GPS) specifying the government's overall objective for gas: to ensure that gas is delivered to existing and new customers in a safe, efficient, fair, reliable, and environmentally sustainable manner. It set down the guiding principles and timetable for the gas industry to establish a governance structure and decision-making process to manage the further development of gas market arrangements and to prepare a work plan in relation to production and wholesale markets, access to transmission and distribution networks, retail markets and gas safety. The 2003 GPS also set down the government's approach to negotiating open access to the Maui pipeline.

[3] In November 2001, the owners of the Maui field announced that the Maui reserves may be materially lower than previously estimated and below the aggregate of contracted quantities. A contractual process was initiated by the owners of the Maui field in December 2001, in accordance with the contract with the New Zealand government, to formally re-determine the economically recoverable natural gas reserves of the Maui field. In June 2002, the owners of the Maui field, the New Zealand government and the various downstream gas users, including Methanex, agreed to re-determine the Maui reserves by way of an arbitration process involving an independent expert appointed by the parties to the gas contract. On February 6, 2003, the independent expert released a final re-determination report determining reserves at a level that is substantially lower than the aggregate of contracted quantities under the Maui head contract.

[4] This is often referred to as the 'Methanex 20/20 deal'.

While the government was successful in negotiating open access to the Maui pipeline, the gas industry struggled to establish an appropriate governance structure. After extensive discussions within the gas industry, it was determined that the governance structure contemplated in its 2003 GPS needed statutory powers and functions to be effective.

As a consequence, in October 2004, the government replaced the 2003 GPS with its Government Policy Statement on Gas Governance, which signalled a number of important changes to the government's policy on the gas industry.

- Co-regulatory model — the government confirmed its preference for industry-led solutions where appropriate, indicated its intention to implement in cooperation with the gas industry a co-regulatory model of governance, and has highlighted its intention to establish a Crown regulatory authority, the Energy Commission, if the corresponding industry body did not deliver the expected outcomes;
- Amended legislation — the government noted amendments to the Gas Act, allowing the Minister of Energy to approve an industry body to recommend regulations and rules in the areas of wholesaling, processing, transmission and distribution of gas; and allowing the government to directly regulate retail and consumer issues.
- New outcomes — the specific outcomes the government sought from the industry were adjusted to add the facilitation and promotion of the ongoing supply of gas, the enhancement of investment incentives, and the achievement of the government's climate change objectives by minimising losses and promoting energy efficiency;
- Government oversight — the government set a deadline December 2005 for the industry body to bring forward all the industry-led solutions.

As a consequence of the 2004 GPS, the gas industry established an incorporated company, Gas Industry Company, as a vehicle for the delivery of industry-led solutions for gas industry reform. The Governor-General approved Gas Industry Company as an 'industry body' under section 43ZL of the Gas Act 1992 (Gas Act) on 22 December 2004. As an approved industry body, the Gas Industry Company has a range of objectives as set down directly in the Gas Act and in the 2004 GPS, and these are reflected in its constitution.

N.1.5 Upstream Incentives

The government responded to the looming gas shortage through a range of upstream measures that reduce the overhead costs of exploration activity, and improve the profitability of newly developed fields. These reforms, introduced in May 2004, represented a stimulus to gas exploration. They applied for the period 30 June 2004 to 31 December 2009, and included:

- Reducing the ad valorem royalty rate from 5% to 1% for gas (oil remaining at 5%) for discoveries made within the period;
- Allowing a deduction in relation to the accounting profit royalty on production from discoveries, within the period, of exploration and prospecting costs incurred in New Zealand and allowing such costs to be carried forward with interest;
- Reducing the accounting profit royalty from 20% to 15% on the first $750 million (cumulative) gross sales of petroleum offshore and the first $250 million (cumulative) onshore on discoveries within the period;

- $15 million over three years for seismic mapping and increased resources to Crown Minerals to promote New Zealand overseas as a petroleum prospecting destination;
- A review of the tax rules applying to non-resident drilling rig operators, aspects of the capital treatment of development expenditure, and the application of certain GST rules to the oil and gas industry.
- Acquiring and interpreting seismic and other technical data to better attract competitive bids for exploration permits;
- Improved information technology systems to make data readily and freely available to explorers;
- More frequent competitive tenders for permits in frontier petroleum basins;
- Targeted marketing to bring larger international exploration companies to New Zealand;
- Enforcing licence-holder obligations more rigorously by requiring them to carry out their projected work programmes; and
- Removing tax rules that had created incentives for companies to keep offshore drilling rigs and seismic vessels in operation for less than 183 days in New Zealand waters.

The government sought competitive bids for block offers of exploration permits for Great South Basin, where petroleum exploration permits were allocated to those persons who are most likely to effectively and efficiently prospect or explore and develop the petroleum resource.

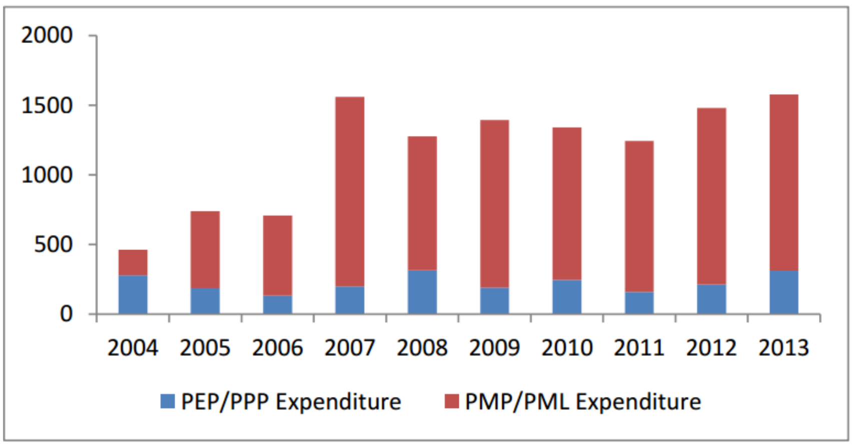
N.1.6 Policy Responses

N.1.6.1 Upstream Responses

The fiscal incentive package offered, combined with market-based incentives to address a looming shortage situation, did stimulate a significant upswing in exploration activity and the expenditure in E&P has been sustained as can be seen from Figure N-2.

Figure N-2 NZ Exploration and Development Expenditure 2004-2013

(Source: Gas Industry Company Limited)



Source: 2014 Energy in New Zealand
PEP = Petroleum Exploration Permits
PPP = Petroleum Prospecting Permits
PMP = Petroleum Mining Permits (production permits)
PML = Petroleum Mining Licences (production permits)

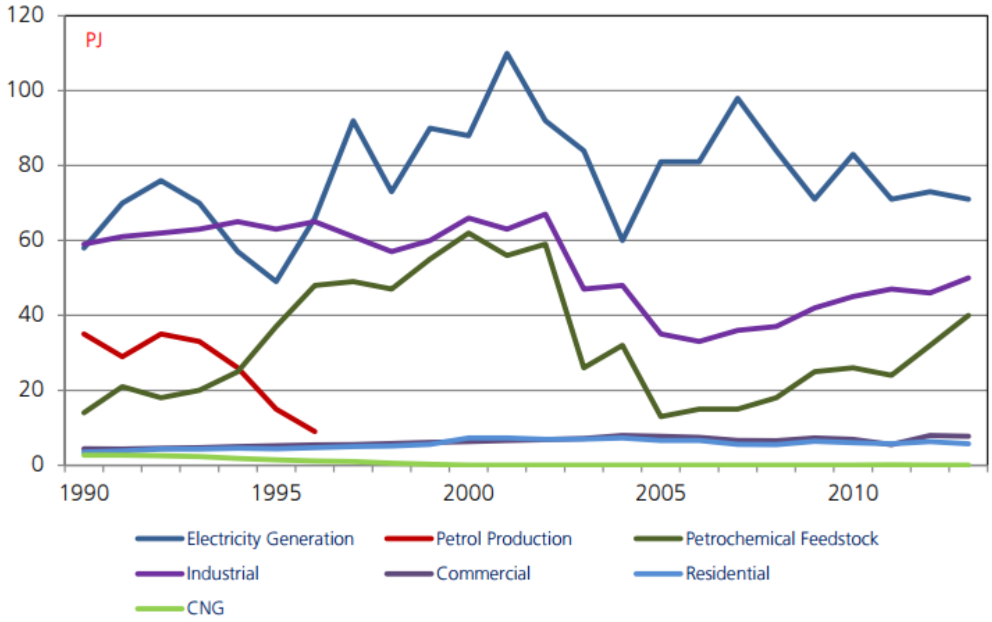
The increase in market prices triggered by gas shortages from Maui also improved the financial viability of previously uneconomic fields, e.g: Kupe, Turangi, Cheal. New Zealand's gas reserves-to-production ratio has strengthened in recent years. Following a period in the early 2000s when the supply horizon dipped to around six years, it has more recently stabilised at around 11 years and, in 2013, increased to 13 years due to reserves improvements at the McKee, Pohokura and Mangahewa fields.

N.1.6.2 Downstream Responses

Gas use trends have been largely influenced by the varying requirements of the predominant demand sources – electricity generation and petrochemical production as shown in Figure N-3. In particular, methanol production (Methanex) has acted as a swing user, lowering or increasing output during times of reserves reduction or growth, and responding to influences such as the New Zealand gas price compared with other countries with competing methanol facilities, and the international methanol price itself.

Figure N-3 Gas Use by Consumer Group 1990 -2013

(Source: Gas Industry Company Limited)



Feedstock gas for methanol production has consequently fluctuated significantly in the past decade. In 2004, the two production trains at Methanex's Motunui methanol plant were shut down, and the company produced only from its Waitara Valley plant. Four years later, Methanex recommissioned one of those trains and closed its Waitara Valley plant. This period of reduced feedstock gas uptake also impacted on the volume of gas – recorded as industrial usage – that these plants separately use for their operational processes. With an improving reserves outlook and a favourable New Zealand gas price, Methanex reached a 10-year supply agreement with Todd Energy in 2012, under which Todd is further developing and expanding its Mangahewa field gas production capability, and Methanex restarted the second Motunui production train in 2012. In October 2013, it recommissioned the Waitara Valley plant, returning to full production.

The increase in Methanex's demand has attracted some comment about its possible impact on the industry, including whether it could displace other uses for the gas. However, there is no question that the presence of Methanex enhances the domestic market attraction to explorers and – as demonstrated by the arrangement with Todd Energy – it has been successful in unlocking a prospect in a way that others have not been able to achieve. Given the costs of field development, Methanex represents a load that can underpin the market and assist government objectives to incentivise upstream exploration and development investment. These developments, and the trend towards a peaking rather than baseload function for gas-fired electricity generation, raise the prospect of methanol production moving from a swing to market-setting role.

N.1.7 Government Policy Framework

In the past four decades, the policy approach of various governments to the oil and gas sector has transitioned from direct financial involvement, to divestment of those interests and, ultimately, oversight of the now privately-owned industry through policy directives and regulation. Key policies and objectives for the upstream and downstream sectors of the gas industry are contained in the following documents:

- New Zealand Energy Strategy - details the government's overall policy aims for the energy sector, and confirms the development of New Zealand's petroleum and minerals resources as a key element in wider economic growth objectives. It establishes four priorities: diverse resource development, environmental responsibility, efficient use of energy and secure and affordable energy.
- National Infrastructure Plan - launched in 2011 it is designed to reduce uncertainty for businesses by outlining the government's intentions for infrastructure development over a 20-year timeframe. It presents a framework for infrastructure development, rather than a detailed list of projects
- Gas Act and GPS. The government's policy objectives for the gas sector are set out primarily in the Gas Act 1992 and the GPS. Together they establish an umbrella policy objective for gas 'to be delivered in a safe, efficient, fair, reliable and environmentally sustainable manner'.

  Other policy objectives of the Gas Act include:

  - The facilitation and promotion of the ongoing supply of gas meets New Zealand's energy needs, by providing access to essential infrastructure and competitive market arrangements.
  - Barriers to competition in the gas industry are minimised.
  - Incentives for investment in gas processing facilities, transmission and distribution, energy efficiency and demand-side management are maintained or enhanced.
  - Delivered gas costs and prices are subject to sustained downward pressure.
  - Risks relating to security of supply, including transport arrangements, are properly and efficiently managed by all parties.

  Further objectives and outcomes the government wants to be taken into account in recommendations for rules or regulations, are established by the GPS, and include that:

  - Energy and other resources used to deliver gas to consumers are used efficiently.
  - Competition is facilitated in upstream and downstream gas markets by minimising barriers to access to essential infrastructure to the long-term benefit of end-users.
  - The full costs of producing and transporting gas are signaled to consumers.
  - The quality of gas services where those services include a trade-off between quality and price, as far as possible, reflect customers' preferences.

- Commerce Commission – Economic Regulation Commerce Act 1986 regulation of gas pipelines is designed to ensure that suppliers of natural monopoly services have similar incentives and pressures as they would have if operating in a competitive market.

N.1.8 Evolution of the Regulatory Framework

N.1.8.1 Co-Regulation Model

New Zealand has an innovative co-regulation model in which gas industry governance is developed in a partnership between industry and the government. It mirrors a co-regulatory gas body developed in New South Wales, Australia at the time, and was specifically requested by the industry, which argued for a 'right-sized' governance body for the smaller New Zealand gas industry, and a regime that recognised the 'challenger' nature of gas as a generally optional fuel in increasingly competitive consumer energy markets.

It is innovative in that it tasks an industry body (the Gas Industry Company) with performing much of the policy analysis that would usually be performed by a Ministry. Essentially, the industry is given the opportunity to develop industry practices, with a back-up of the force of law through regulation and the ability of the Minister to step in to counter any hold-out behaviour, or an inability of participants to reach an appropriate, workable arrangement. The co-regulatory model is intended to encourage the delivery of industry-led solutions for gas industry reform where practicable, and the recommendation of regulatory arrangements where appropriate.

The system of co-regulation, with the government and the Gas Industry Company sharing regulatory oversight, does seem to be working. While there might be some fear that the Gas Industry Company becomes a trade association rather than a regulator, this does not seem to be the case and there does not appear to be any cause for concern along these lines.

N.1.8.2 Regulation of Transportation Services

In the two decades since 1990, the regulatory framework turned full circle for gas transportation services. Significant changes implemented with the new Gas Act in 1992 ushered the industry away from price controls and protected retail franchises into a deregulated era and the opening of competitive gas markets. Now, price controls have been re-imposed for open access pipeline businesses, although contestable gas wholesaling, retailing and metering services are not subject to price regulation.

N.1.9 Applicability to T&T

The experience of New Zealand holds some parallels with T&T, although New Zealand's gas industry is less dominated by export industry consumers. The key lessons which can be extracted for T&T include:

- The improvement in R-P ratio and revitalised investment in the upstream sector was in response to a clear and coherent government policy which resulted in tangible incentives to attract industry investment;
- Greater governance of the energy sector has been achieved in collaboration with industry through the Gas Industry Company, but was only effective when supported with statutory powers for the Minister to enforce compliance if necessary. The establishment of an industry body also transferred much of the policy analysis that would normally be executed by the Ministry to the industry;
- The shortage of gas led domestic gas prices to rise towards international pricing levels;
- Methanex reacted to gas pricing and availability changes by mothballing and subsequently re-commissioning trains in response to gas and methanol market conditions, effectively becoming a swing consumer for a supply constrained market.

The New Zealand experience supports the application of tangible fiscal incentives to stimulate upstream E&P investment, combined with industry participation in governance of areas such as infrastructure access, backed up with regulatory powers to allow the Minister to intervene as required. An increase in gas prices is inevitable as the supply becomes constrained and transparent market information will support medium term business decisions in the downstream sector allowing demand to react to gas pricing signals.

N.2 BRUNEI

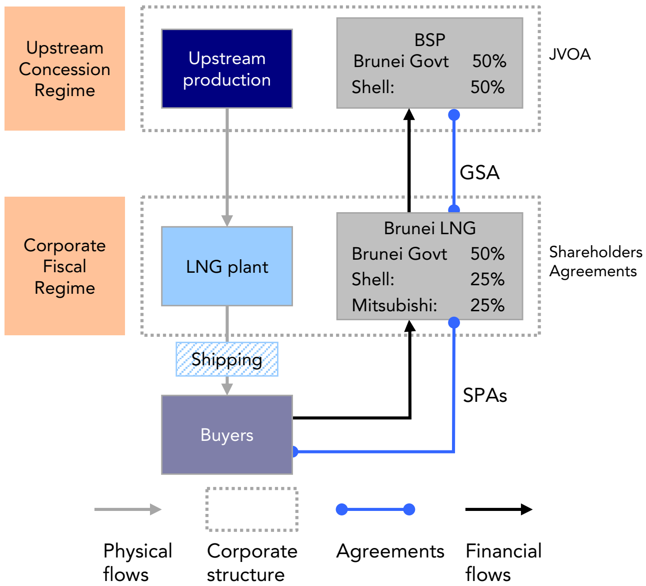
N.2.1 Overview

Brunei presents an interesting parallel to T&T's gas industry in that both are relatively small countries which initially developed oil industries before commercially exploiting gas for export in the later decades of the last century. Both countries are now seeking to respond to a declining reserves base.

N.2.2 Gas Sector Structure

Brunei has only one major gas consumer, the Brunei LNG plant with a capacity of 7.2 MMt/y commenced production in 1972 and was the first LNG plant in the Asia-Pacific region. An 0.85 MMt/y methanol plant was added in 2009 but this consumes a relatively small amount of gas.

Figure N-4 Brunei LNG Commercial Structure



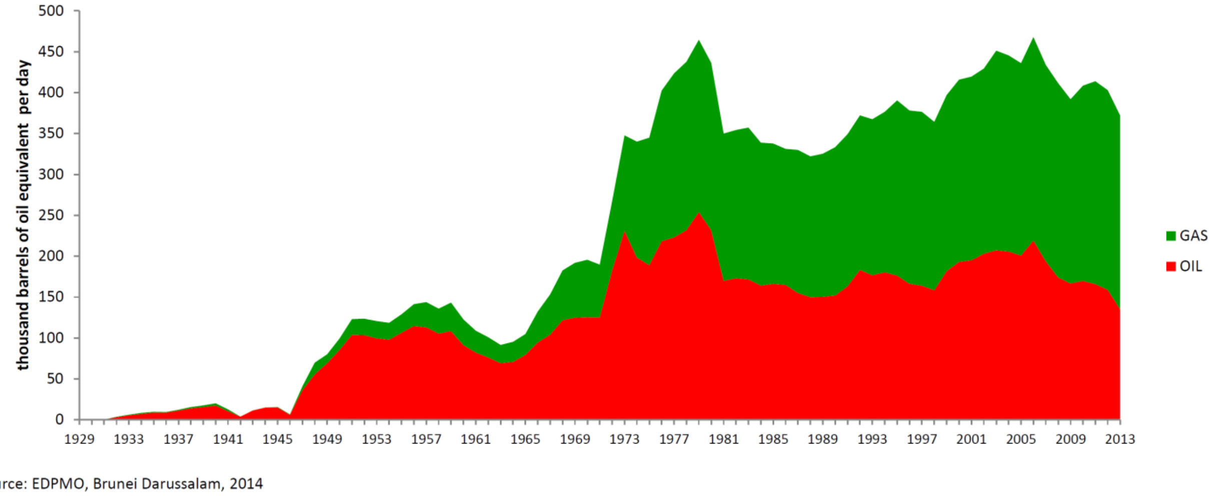
The commercial structure of the Brunei LNG project is summarised in Figure N-4. The upstream concessions containing the producing fields are held by BSP, a joint venture between Shell and the Brunei government. Gas is sold to the LNG plant in which Shell and Mitsubishi each hold a 25% interest with the remaining 50% held by the government. Brunei LNG sells processed LNG to overseas customers.

The Brunei Methanol Plant is a joint venture between the government (25%), Mitsubishi (50%) and Itochu (25%) and relies upon technology licensed from Mitsubishi. The plant capacity is 0.85 MMt/y, requiring a feed gas rate of circa 75 MMcf/d (compared to the LNG plant feed gas rate of circa 1,000 MMcf/d). The final investment decision was taken in May 2007 and commercial operation commenced in Q2 2010.

N.2.3 Industry Development

The Brunei E&P industry commenced oil production early in the 20th century. Associated gas was produced in limited quantities from the 1950s but production increased significantly in the late 1960s with the start of LNG production.

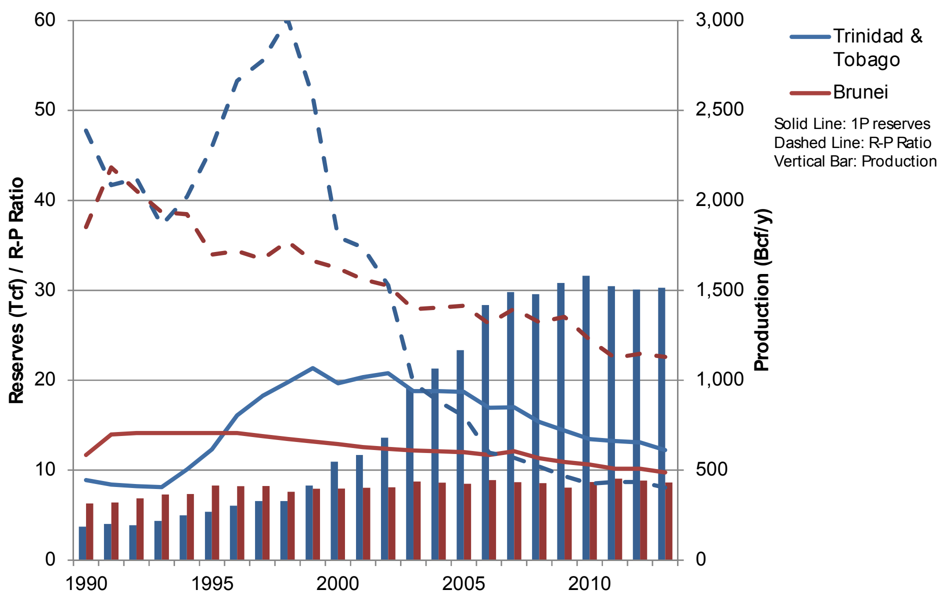
Figure N-5 Brunei Oil and Gas Production
(Source: EDPMO, Brunei Darussalam, 2004)



The Southwest Ampa gas field was discovered in 1963, which underpinned FID on the Brunei LNG project in 1970 supported by sales agreements with TEPCO, Tokyo Gas and Osaka Gas. The plant has a capacity of 7.2 MMt/y across 5 trains. First gas was delivered in December 1972 and Train 5 was completed in 1974.

The reserves and production profile of Brunei is compared to Trinidad and Tobago in Figure N-6.

Figure N-6 Brunei and T&T Production and Reserves History
(Source: BP Statistical Review of World Energy 2015)



Brunei's 1P reserves were fairly constant at 15 Tcf during the early 1990s and production caused only minor erosion of the reserves base, indicating that produced gas volumes were being replaced by new discoveries and proving up of contingent resources to reserves. However, since 2000 there has been a steady decline in reserves to the current level of just under 10 Tcf at end 2013. Over this period only 40% of production has on average been replaced by new reserve additions. At current production rates of circa 430 Bcf/yr Brunei has a R-P ratio of 23 years.

The contrast with T&T is illustrated in Figure N-6. While Brunei has not expanded its gas industry beyond the initial development of 7.2 MMt/y of LNG, T&T responded to significant gas discoveries in the late 1990s which pushed 1P gas reserves above 20 Tcf with a period of significant expansion of gas consuming industries until production reached 1,600 Bcf in 2010. The sharp rise in R-P ratio up to 60 years driven by the 1990s gas discoveries has been followed by a steady decline as production capacity has increased and produced reserves have not been replaced. The two countries now have a similar 1P reserves base, but the significantly greater gas demand that has been developed in T&T has pulled the R-P ratio down to 8 years compared to 23 years in Brunei at end 2013.

N.2.4 Policy Development

In 2014 The government issued an energy White Paper outlining the approach for managing further development of the energy sector in line with the National Vision 2035 which had been developed previously by the government. The objectives of National Vision 2035 are:

- To make Brunei a nation which will be widely recognised for the accomplishment of its educated and highly skilled people as measured by the highest international standards.
- To achieve quality of life that is among the top 10 countries in the world.
- To build a dynamic and sustainable economy with an income per capita among the world's top 10.

The key points of the energy policy to support this vision can be summarised under three strategic goals, each measured by a series of KPIs summarised in Table N-1.

Strategic Goal 1: Strengthen and Grow Oil and Gas Upstream and Downstream Activities directly addresses the performance of the oil and gas sector in Brunei with KPI's that acknowledge the inherent tension between the objectives of growth and strength.

KPI 1 targets a reserves replacement ratio (the ratio of reserves additions from exploration and appraisal to volumes produced in a given year) in excess of 1, compared to an average of 0.4 over the last decade. Achieving this goal will stabilise the R-P ratio but is dependent on a continuous stream of incremental volumes through exploration and appraisal success. The white paper advocates revising production targets should this KPI consistently fail to meet the target of 1, requiring a reduction in gas production rates to preserve gas in the absence of incremental volume additions. The government has identified three initiatives to stimulate reserves additions in the conventional gas sector:

- Building interest in unlicensed acreage;
- Appraisal of mature fields; and
- Support for marginal field developments.

Table N-1 Brunei Government Policy Goals and KPIs

(Source: Energy Department-Prime Minister's Office)

3 Strategic Goals and 10 KPIs Brunei Darussalam's energy sector in 2035

KPI		Definition	Unit	Target		
				2010 Baseline	2017	2035
Strategic Goal 1: Strengthen and Grow Oil and Gas Upstream and Downstream Activities						
1	Oil and Gas Reserve Replacement Ratio	Ratio of expectation reserves added each year and annual production volume (oil and gas)	Ratio	0.5	>1	>1
2	Oil and Gas Production	Gross production of oil and gas	Barrel Oil Equivalent (BOE) per day	408,000	430,000	650,000
3	Downstream Economic Output	Revenue from sales of products	BND Million per year	300	3,000	5,000
Strategic Goal 2: Ensure Safe, Secure, Reliable and Efficient Supply and Use of Energy						
4	Ensure safe operations	Number of major accidents for the energy industry	Number per year	0	0	0
5	Energy Intensity	Ratio of primary energy demand for all sectors and GDP	Ton oil equivalent per USD Million of GDP (2005 baseline)	390	320	215
6	Renewable Energy in Total Power Generation Mix	Power generation from renewable sources of energy	MWh	808	124,000	954,000
7A	Reliable Energy - Power Outage (>1 hour)	Number of incidents of power outages of more than 1 hour duration in a year	Number per year	>300	100	<50
7B	Reliable Energy - Interruption in supply of Transport fuel	Number of incidents where there is a supply interruption for transportation fuel for general public consumption at more than 50% fuel stations at any district in a given day	Number	0	0	0
Strategic Goal 3: Maximise Economic Spin-off from Energy Industry – boost local content and secure high participation of local workforce						
8	Local Content Spending in Energy Industry	Contribution from local industries and workforce in the provision of goods and services supplied to the energy sector in Brunei Darussalam	%	15	50	>80
9	Employment in Energy Industry	Number of employment in the energy industry	Number	20,000	30,000	50,000
		Number of locals working in the energy industry	Number	10,000	20,000	40,000
10	Local Companies Development	Number of local companies that have at least 40% of sales of goods and services generated from overseas market	Number	0	8	30

There will also be a greater emphasis on assessing the potential for unconventional gas development.

KPI 2 targets a 50% increase in annual production over the next 20 years, measured in barrels of oil equivalent of both oil and gas production. While this objective may conflict with KPI 1 when discoveries are insufficient to maintain the reserves replacement ratio at higher production rates, the initiatives which support it are closely aligned with those for KPI 1, with a focus on rejuvenation of existing fields, supporting development of smaller fields through sharing of infrastructure and attracting international IOC expertise into the upstream industry. Given the comments supporting KPI 1, it appears that meeting KPI 2 will be conditional on achieving sufficient exploration and appraisal success to support the KPI 1 target of >100% reserves replacement.

KPI 3 addresses building Downstream Economic Output. This performance indicator will track the local value that is extracted from oil and gas produced in Brunei through downstream opportunities such as gas, crude and condensate based petrochemicals, with the intent of extracting greater national value from produced hydrocarbons and supporting other core government priorities such as employment diversification and improving energy efficiency. An expansion is planned for Brunei's refinery capacity which supplied 60% of transportation fuel demand in 2014. In addition opportunities to pursue gas and naphtha based ethylene crackers, conversion of methanol to propylene and other speciality chemicals and establishment of a value-added aluminium derivatives industry are under consideration.

Strategic Goal 2: Ensure Safe, Secure, Reliable and Efficient Supply and Use of Energy reinforces the sustainability message of KPI 1 with initiatives to reduce national energy intensity and stimulate renewable energy production and also emphasises improvement of the reliability of gas, power and transportation fuel supplies to the nation.

Strategic Goal 3: Maximise Economic Spin-Off from Energy Industry - boost local content and secure high participation of local workforce reinforces the intent of KPI 3 to extract the greatest value for the nation from the hydrocarbons that are produced through greater local content in energy industry spend, greater national employment in the energy industry and development of local companies.

N.2.5 Industry Response

The industry response to the government initiatives presented in the 2014 White Paper is still evolving. The White Paper notes that although the reserves replacement ratio has been low in the previous decade, recent ratios have been higher and above 1 in last five years and the major concessionaires have developed plans to ensure that the success of the past few years is sustained for the rest of this decade, with significant exploration programmes in place.

From an E&P company perspective a formal link between production targets and reserves replacement sends a strong message and, if supported with fiscal incentives to share the cost of the required investment, is well placed to influence company decision making towards rebuilding the nation's reserve base.

N.2.6 Applicability to T&T

Brunei has clear parallels with T&T. Both countries are struggling to replace produced reserves exploited to supply an export focused gas industry and are keen to extract the greatest value for their nation from the produced hydrocarbons. Key characteristics of the Brunei White Paper that stand out include:

- Integration of the oil and gas sector policy into a broader energy strategy, itself a part of a national vision for 2035.
- An emphasis on sustainability of the industry, balancing aspirations for growth with specific targets to raise the reserves replacement ratio above 1 and reduce national energy intensity.

- Within the context of sustainable production levels, a focus on extracting the greatest national value from the hydrocarbons produced through value adding downstream industries, skills development and employment.

T&T has achieved a higher reserves replacement ratio than Brunei of 0.56 over the last decade, but this still falls short of full replacement to support a sustainable production industry. The significantly greater gas demand from a similar reserves base makes the challenge facing T&T more immediate than Brunei, reflected in T&T's proven R-P ratio of 8 years. Emphasis on the sustainability of the oil and gas production industry in T&T through tracking of KPI's such as the reserves replacement ratio and adjusting upstream production forecasts to protect the future of the industry should be considered in formulation of government policy.

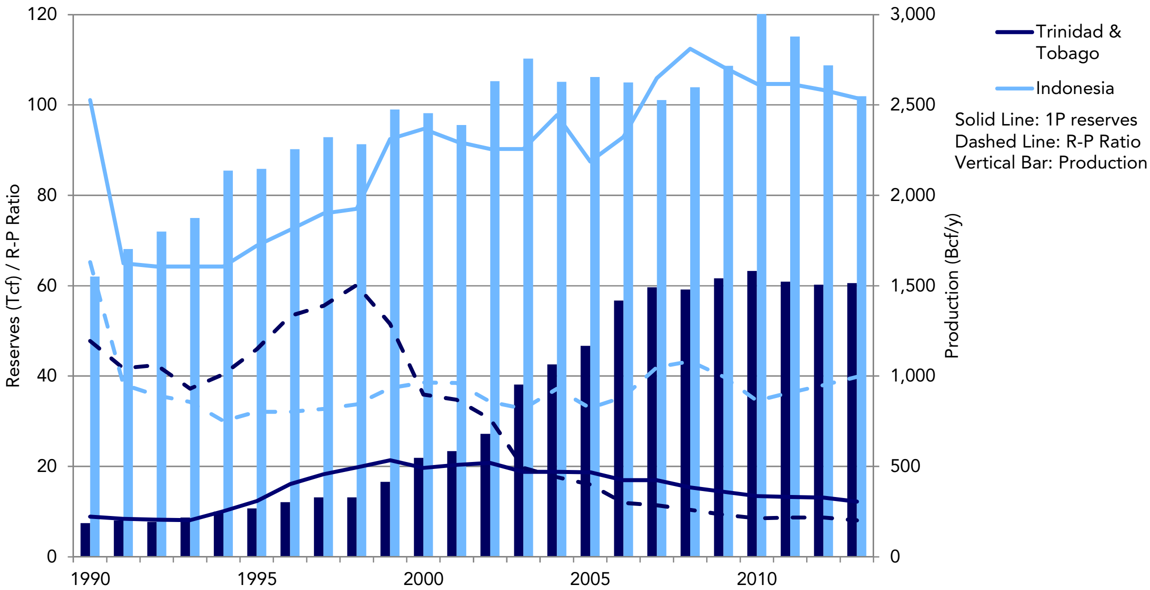
N.3 INDONESIA

The gas economy in Indonesia, although larger, has some similarity to the gas economy in T&T. The Indonesian gas industry grew with through the establishment of export projects to be one of the world's largest LNG producers and a major producer of petrochemicals (ammonia, urea and methanol). However, since 2003 production from Indonesia's mature gas basins has begun to decline in parallel will an increase in domestic demand and the start of pipeline gas exports to Malaysia. The rise in demand combined with a fall in supply potential has triggered decisions by the government and industry to stimulate development of the remaining, less economic, gas resources.

N.3.1 Overview

At a high level, Indonesia's gas industry appears to be in good health. Figure N-7 compares the development of 1P reserves, annual production and R-P ratio in Indonesia with T&T. As Indonesia's production rate climbed with development its gas export industries through the 1990s and early 2000s the reserves base also expanded resulting in a relatively stable R-P ratio of circa 40 years.

Figure N-7 Indonesia and T&T Production and Reserves History
(Source: BP Statistical Review of World Energy 2015)



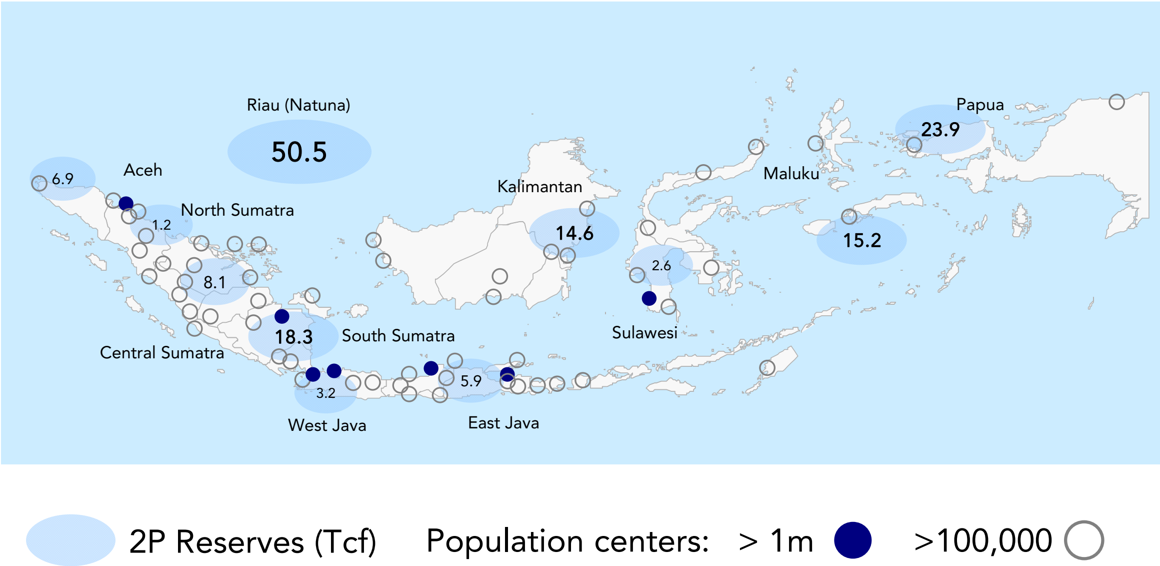
Indonesia has abundant gas reserves, but faces the decline of mature production areas and dislocation of remaining reserves from demand centres, as shown in Figure N-8 where high population and gas demand areas on Sumatra and Java are far away from the bulk of remaining gas reserves in Kalimantan, Papua and Riau.

The challenge for Indonesia is therefore twofold:

- Stimulation of production in mature basins where remaining gas fields are smaller and less attractive to develop.
- Development of more remote large fields located in deeper water, making them more difficult to monetise (high CO_2 content is also an issue for example in Riau).

It should also be noted that Indonesia also has promising Coal Bed Methane (CBM) resources which could hold as much as 450 Tcf of technically recoverable gas.

Figure N-8 Indonesia Held 150 Tcf of Conventional Gas 2P Reserves in 2013
(Source: MoENR Indonesia)



N.3.2 Gas Sector Structure

Slightly more than 45% of Indonesia's gas production was exported in 2013. Singapore imports gas from Indonesia's Sumatra and Riau province, while LNG exports draw gas from Kalimantan (Bontang LNG plant) and Papua (Tangguh LNG plant). The Arun LNG plant located in North Sumatra ceased production in 2014 after 47 years in operations.

While upstream production is still dominated by international oil companies (Inpex, Total, Chevron, ENI etc.), state owned entities have a growing role: PT Pertamina (oil & gas company), PT PLN (Power utility), PT PGN (Gas utility) and finally SKKMIGAS (oil & gas regulator).

Indonesia's gas resources have been developed under a Production Sharing Contract regime similar to that employed more recently in T&T. A key characteristic for Indonesian LNG projects is that the entire project infrastructure including the LNG plant lies within the PSC regime, rather than under a separate corporate entity as has been established in T&T. Under this structure the LNG plant investment is recovered through cost production under the PSC terms and the infrastructure subsequently becomes the property of the Indonesian state. Thus the facilities at Bontang and Arun have reverted to the Indonesian state after the expiry of the PSC term.

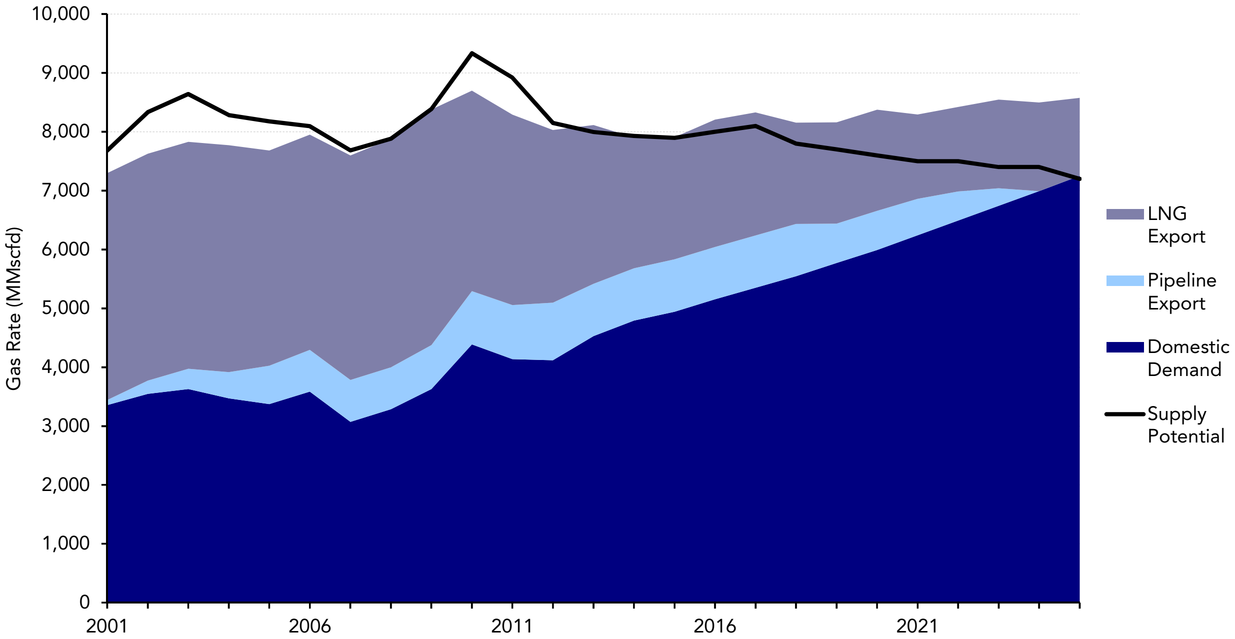
N.3.3 Industry Development

Since the early 2000's Indonesia's gas industry has faced the combination of a plateaued and subsequently declining existing production base as mature fields have begun to decline, combined with significant contractual gas export obligations and a rising domestic demand for gas in the main population centres on Java.

The pressure on gas exports as demand outstrips supply is illustrated in Figure N-9. The slow decline of gas deliverability in the early 2000's has led to the gradual retirement of older LNG production capacity at Arun and Bontang. The rising demand in Java and Sumatra is forecast to out-strip the capacity of local gas resources and will be met instead by LNG imports to these areas. The very tight supply – demand position in 2008-09 triggered LNG import infrastructure development, leading to the West Java FSRU in 2012 and Lampung FSRU in South Sumatra in 2014. More recently in 2015, the Arun LNG plant was converted to operate as an import terminal to supply North Sumatra gas demand, utilising the existing LNG storage tanks from the retired LNG production facility. Arun is the first onshore LNG receiving terminal in Indonesia.

Figure N-9 Historical and Forecast Indonesian Gas Supply and Demand

(Source: MoENR, Indonesia)



The forecast trends in domestic demand and gas supply potential shown in Figure N-9 suggest that Indonesia's remaining contractual export commitments will gradually be offset by LNG imports as production capacity further declines and demand rises until the country may become a net LNG importer in circa 2025. The exact timing of this point will be driven by actual demand growth and the extent to which the government and industry can arrest and possible reverse the decline in production deliverability. However, in anticipation of this trend the government recently announced that LNG exports will be terminated by 2040.

Two world scale ammonia urea plants at Arun were established in the 1980s PT Asean Aceh Fertiliser (330 kt/y ammonia, 560 kt/y urea) and PT Pupuk Iskander Muda (386 kt/y ammonia, 570 kt/y urea). The fertiliser manufactured in Indonesia was sold into the domestic market at a government-set price, well below the prevailing international prices. At the highest retail price (HET) set by the government, a fertiliser factory could pay not more than US$2/MMBtu of gas. The PT Asean Aceh plant stopped operations in 2003 after it received no more gas supply from Arun gas field operated by ExxonMobil Indonesia (EMOI). EMOI stopped gas supply after failure to reach agreement on gas price. The plant was finally shut in in 2005 after several years of major losses as the government was unable to fulfil promises of supply. The plant was auctioned in June 2006. The PT Pupuk Iskander plant mothballed one train in 2004 and by 2005 production in the remaining operating facility dropped below 70% with unreliable supply. The project remained in partial operation through 2010 through the use of a gas swap arrangement with another fertiliser plant in Kalimantan. From 2010 a 10 year gas supply agreement was reached with a new supplier with a floor price related to urea prices.

N.3.4 Policy Development

Gas sector policy in Indonesia is set within the framework of a National Energy Policy, of which the following are particularly pertinent to gas:

- Energy Availability - improving proven reserves of fossil energy, rationalising of gas and coal, optimising energy production, transportation and distribution systems.
- Energy Supply Priority - minimising the use of petroleum, optimising natural gas and new energies, coal as mainstay and security of national energy supply, and using nuclear energy to support the security of national energy supply in large scale with strict consideration of security.
- National Energy Resource Utilisation - utilisation of energy resources according to considerations of capacity, sustainability, economy, and environmental impact.
- National Energy Reserves - national energy security in order to mitigate energy crises and emergency, whether caused by natural causes or the stability of world geopolitical condition.
- Energy Price, Subsidy, and Incentive - regulating energy prices, subsidies, and incentives in order to ensure the supply and business of energy with continued consideration of the community's capacity.
- Energy Infrastructure - improvement of energy infrastructures and encouraging the solidification of national energy industry.

Indonesian authorities have implemented a number of specific policies to address the conflicting demands on the country's energy resources:

N.3.4.1 Domestic Market Obligations

The Domestic Market Obligation requires oil and gas producers to reserve a volume of production for the Indonesian domestic market

- A domestic market obligation was first stipulated in Law No. 15 in 1962, but applied only to oil production.
- The Oil and Gas Law No. 22/2001 along with Government Regulation No. 35/2004 on upstream regulation required that all new developments (i.e., after 2001) must set aside a maximum of 25% of production for the domestic market.
- Confusion reigned when the constitutional court nullified this law on the grounds that the clause on maximum volume contradicted the Indonesian Constitution of 1945.
- In 2008, under Minister of Energy and Mineral Resources Regulation No. 02/2008, PSC contractors were obliged to provide 25% of gas production to the domestic market, rather than a "maximum of 25%" of production.
- In 2010, further clarification gave priority for supply of gas to oil producers, fertilizer plants and utilities.

In practice, domestic market obligations are negotiated with the government on a case-by-case basis

- The government has said that the domestic market obligation policy should not impede contractors from fulfilling their role in developing upstream assets by eroding project economics.
- PSC holders are allowed to sell their volumes abroad if negotiations with domestic buyers fail.
- Project sponsors with no official domestic market obligation tend to allocate some production volumes to the domestic market in order to expedite government approvals for their LNG projects.

The domestic market obligation has continued to evolve. LNG-related upstream projects which have recently received approval have reported 40% domestic market obligation clauses (compared to the regulated 25% obligation). This has required the price offered for the domestic-bound LNG to increase to levels close to international market prices, in order to make LNG project developers more or less indifferent to where the LNG is sold. In August 2015 it was reported in that PLN had contracted for 40% of the capacity of the yet to be sanctioned Tangguh Train 3 development which is struggling to sell the remaining capacity in the current over-supplied market. PLN is currently taking a cargo a month from Tangguh to Pertamina's converted Arun receiving terminal priced at 13% of the Realized Export Price for Indonesian crude oil plus $1/MMBtu, a price level in line with international market contract prices.

N.3.4.2 Domestic Gas Pricing

Historically gas prices have been low in Indonesia for similar reasons to the low gas prices in the earlier years of T&T's development. This was driven by a combination of government policy which controlled the price of gas for domestic consumption and power generation, low feedstock prices required to establish the large gas consuming industrial sector and relatively attractive development economics of the foundation major gas fields.

However, as demand started to outstrip supply prices began to increase and from 2010 the price of gas received by gas producers tripled in three years from $2.0/MMBtu to $6.0/MMBtu. In parallel the government has acted to gradually remove subsidies that have kept domestic fuel prices artificially low. In December 2014, the government abolished $18 billion of fuel subsidies, taking advantage of the collapse of global oil prices to avoid a sudden and unpopular increase in the price paid by local consumers.

Poten expects gas price reform to continue in parallel with a government drive to further develop energy infrastructure, including gas pipeline connectivity, partially financed by savings on abolished subsidies scheme. The rise in gas prices will also support continued diversification of fuel sources to meet growing demand. Of the 35 GW of new power generation capacity planned for 2015-20, circa 90% is initially planned to be fuelled with cheap and plentiful local coal. Geothermal and other renewable energy sources are expected to take an increasing share of this market, but cheap domestic coal will remain the energy of choice for base load power.

N.3.4.3 Support fort Marginal Fields

Various support mechanisms, including fiscal incentives, are utilised by Indonesia to promote development of as many viable fields as possible. Government support is provided in a myriad of forms, from accelerated cost recovery for a single well to broader incentives for the costly and relatively small discoveries in deepwater East Kalimantan, intended to result in a government unofficial target of 15 to 20% IRR for the upstream investor. Rent is extracted throughout the processes if the government perceives that excess rent is available. Additional incentives are provided if the government is satisfied that they are required to make the project economic. Although these processes work very slowly, and sometimes result in project delays, they do promote development of marginal gas fields if the development is economic on a gross basis.

All gas and LNG sales in Indonesia require two government approvals: 1) gas allocation and 2) price. Gas allocation approval pegs a specific tranche of production from a PSC to a specific sales contract and acts as a tool for the government to preferentially allocate artificially low priced markets, such as petrochemicals and power, to producers that it perceives can bear the lower prices and higher priced markets like LNG to projects that it perceives require premium prices to be economically viable. The deepwater developments in Indonesia would be a good example of projects that the government has perceived as requiring access to the premium markets.

Further discussion of Indonesia's marginal field incentives can be found in Appendix E

N.3.4.4 Developing National Energy Companies

In common with most resource holding nations, Indonesia is seeking to develop its national capability in the development and commercialisation of hydrocarbon resources and reduce reliance on IOCs. Indonesia has established state owned entities to manage the national energy resources and develop adequate infrastructure and supply chains to deliver energy to end users, in particular Pertamina in the upstream production area and PLN as the utility and infrastructure provider.

A good example of this trend is the ongoing negotiations between the government and Total, the operator of the Mahakam blocks (supplying the Bontang LNG plant) for the extension of Total's operating licence beyond its expiry in Dec 2017. Total had proposed a five year transition period to transfer operatorship to Pertamina, but the government announced in June 2015 that Pertamina will take operatorship and at 70% interest in the license in January 2018, with the remaining 30% offered to be shared between Total and Inpex, who currently hold 50% each of the block.

N.3.5 Industry Response

Indonesia is seeking to balance the conflicting demands of domestic consumers and businesses with maintaining interest and investment from IOC's, particularly in the context of an at times opaque regulatory system. They have failed to retain existing upstream players and have struggled to attract new investors in recent bid rounds. For example, Exxon, Marathon and Anadarko have all relinquished acreage and key players have delayed development of upstream projects due to uncertainty over the investment climate.

Chevron entered FEED for the development of its deepwater gas project in December 2010, but only took a partial FID on the project in Oct 2014, citing incomplete regulatory approvals for the delay in full FID. Total has also suffered an extended period of uncertainty regarding the extension of the Mahakam blocks licences. However, in June 2015 Eni (operator) and Pertamina signed a 1.4 MMt/y deal that launched the Jangkrik field fast track deepwater project, with deliveries expected to start as early as 2017 and which should last for 7 years. The gas will be liquefied at Bontang LNG plant, for a limited tolling fee of less than \$1.00/MMBtu (Bontang is operated by Pertamina and owned by the Indonesian Ministry of Finance).

N.3.6 Applicability to T&T

Although the challenges of supplying a large and growing domestic demand do not apply to T&T, the Indonesian experience with adjusting domestic gas pricing towards international market levels, the stimulation of marginal fields and the development of national energy companies can be instructive.

The approach to the stimulation of marginal fields is an individual, case-by-case negotiation of fiscal terms and pricing with producers, which contrasts with the common incentives offered to the industry by New Zealand. Although this approach has succeeded to stimulating field development it suffers from being relatively slow, requiring a large bureaucracy to administer the incentives and from a lack of transparency due to the individual and confidential nature of the negotiations. Relying entirely on an Indonesian approach in T&T is unlikely to achieve the goal of maintaining plateau production because this goal requires rapid decision making on the identified short-term supply projects and certainty of fiscal terms and gas pricing to stimulate exploration and appraisal. However, its partial success in Indonesia provides a model for an element of a broader approach which could be applied in T&T.

Building national energy companies and capability is an aspiration shared with T&T. The expiry of PSCs and other operating licenses in the coming years will provide the government with an opportunity to participate more directly and further develop operational expertise across the energy sector.

N.4 MALAYSIA

N.4.1 Overview

Malaysia is the world's second-largest LNG exporter and similarly to neighbouring Indonesia, it is facing rising domestic gas demand in areas distant from its main reserves and production centres. The energy sector as a whole is a critical growth sector for the entire economy, as it represents almost 20% of total GDP and is highly centralised through Malaysia's national oil and gas company, Petroliam Nasional Berhad (Petronas).

Malaysia is seeking to leverage its resources and geographic location to become a regional oil and natural gas storage, trading and development hub that will attract technical expertise and services which can compete throughout Asia.

Malaysia is focused on securing energy supplies through cost-effective means and diversifying its fuel portfolio, which is heavily weighted to oil and gas. Poten expects coal imports and renewable energy to placing increasingly important roles in the future.

N.4.2 Gas Sector Structure

The Malaysian gas sector is controlled by the government:

- Energy policy is set and overseen by the Economic Planning Unit (EPU) and the Implementation and Coordination Unit (ICU), which report directly to the Prime Minister.
- Petronas fulfils dual roles of regulator and participant in Malaysia's oil and gas sector:
  - It is responsible for managing all petroleum licensing.
  - It is directed by the Prime Minister, who controls appointments to the company board.
  - It holds stakes in the majority of oil and gas blocks in Malaysia.
  - By law it must hold a 15% minimum equity participation in Production Sharing Contracts
  - It is the single largest contributor to government revenues, up to 45%, by way of taxes and dividends.
  - It has developed into a world-renowned integrated national oil and gas company with business interests in more than 30 countries.
- Petronas dominates the natural gas sector, with a monopoly on upstream natural gas developments and a leading role in downstream activities and LNG trade:
  - Most natural gas comes from blocks operated by IOCs in partnership with Petronas.
  - Shell remains the largest producer and a key player in the deep water.
  - MISC, a 63%-owned Petronas affiliate, is the second-largest LNG fleet operator in the world, with 27 LNG tankers as well as petroleum tankers and chemical transport ships.
- Government companies control the transmission and distribution sector:
  - Gas Malaysia is the largest non-power gas distribution company in Malaysia and the only one that can operate on Peninsular Malaysia.
  - Sarawak Gas Distribution Company, which is 70% owned by the state government, serves Sarawak.
  - Sabah Energy Corporation distributes gas in Sabah state.

N.4.3 Industry Development

The evolution of Malaysia's gas reserves and production base is compared with T&T in Figure N-10. Malaysia's gas production has grown over a similar period to T&T, reaching almost 2,400 Bcf in 2013. Malaysia's reserves base grew strongly in the 1990 to plateau at circa 40 Tcf, declining only slightly in recent years to 38 Tcf delivering a fairly stable R-P ratio of 17-18 years, falling to 16 years in 2013 due to a spike in production that year.

Figure N-10 Malaysia and T&T Production and Reserves History
(Source: BP Statistical Review of World Energy 2015)

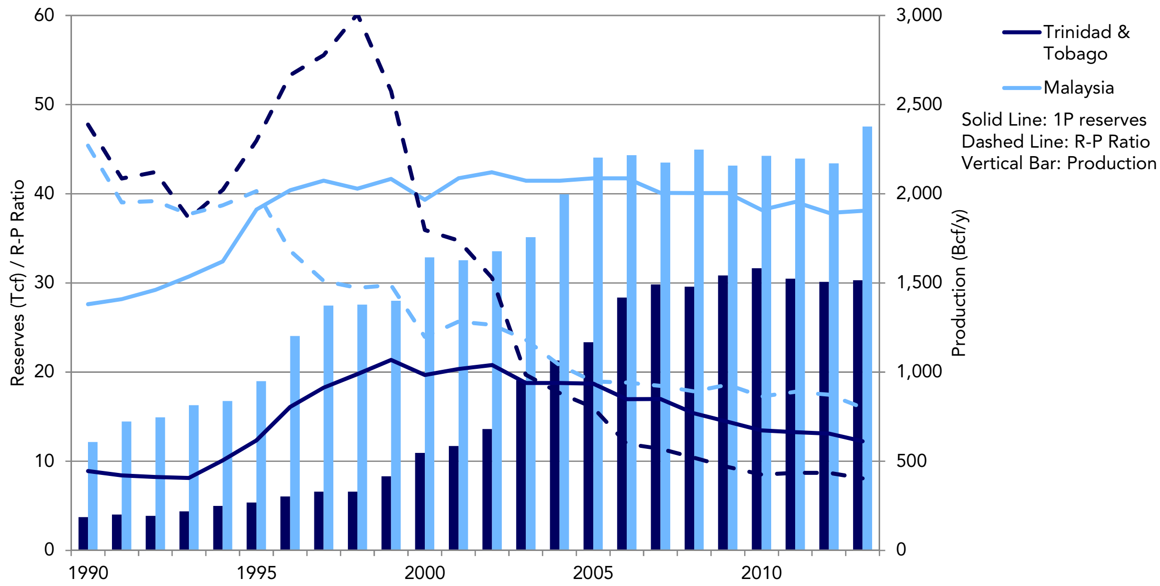
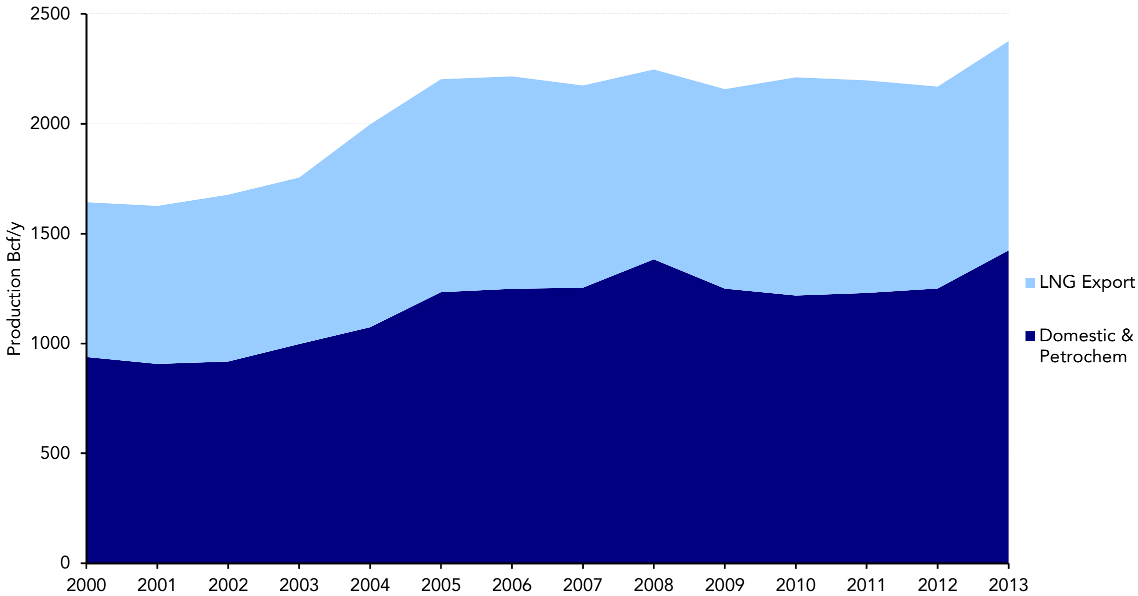


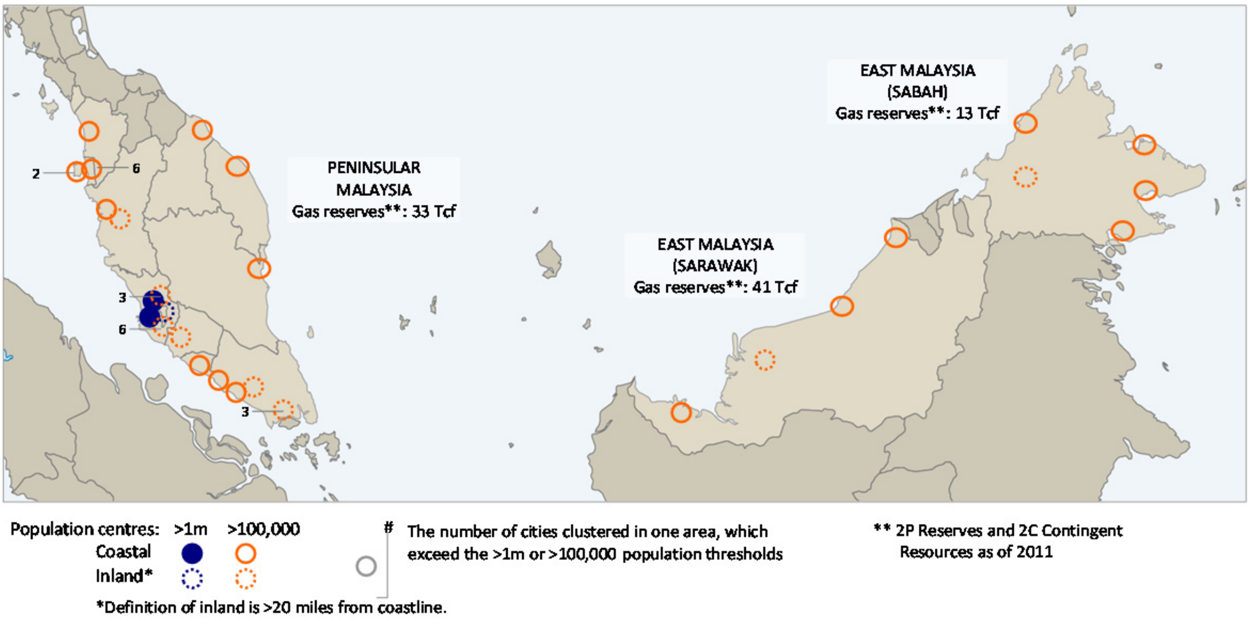
Figure N-11 Gas Demand Growth in Malaysia
(Source: BP Statistical Review of World Energy 2015)



Growth in gas demand in Malaysia over the last decade has been primarily in the domestic and petrochemical area, with LNG export volumes remaining relatively constant following the start of MLNG Tiga in 2003. Gas demand will increase by a further circa 180 Bcf/y with the start of MLNG T9 in 2017.

Malaysia's reserves and demand are distributed over two distinct areas. In the west, Peninsular Malaysia is home to 82% of Malaysia's domestic demand (730 Bcf/y). In the east Sabah and Sarawak each contribute circa 9% to the total domestic demand (circa 80 Bcf/y each) but are home to the large LNG export industry with demand approaching 1000 Bcf/y. Discovered gas reserves and resources are however weighted towards the eastern states with Sarawak and Sabah holding 54 Tcf compared to 33 Tcf in the Peninsula Malaysia area.

Figure N-12 Malaysian Demand Centres and Resource Distribution
(Source: Petronas, Poten & Partners)



Malaysia faces a situation similar to Indonesia where gas production in the country's main domestic demand area (in this case, Peninsular Malaysia) is starting to decline while demand is growing. Although the headline resources adjacent to Malaysia appear high this includes contingent resources not yet proven commercial and masks the decline in established mature basins. Shortages of gas supply in Peninsula Malaysia led to the establishment of an LNG import terminal at Malacca in 2013, with plans for additional import capacity at the Pengerang terminal in Johor.

Regasified LNG will play an increasingly important role in Malaysia's mix for domestic gas consumption going forward. Representing around 5% of gas demand in 2013, the role of LNG is set to reach 30% by 2025, to predominantly satisfy gas demand in Peninsular Malaysia.

N.4.4 Policy Development

Energy policy in Malaysia falls within a national framework launched in 2010. The Economic Transformation Programme (ETP) was formulated as part of Malaysia's National Transformation Programme. Its goal is to elevate the country to developed-nation status by 2020.

The government has focused on efforts to enhance output from the existing oil and gas fields, the new marginal fields as well as exploration and development opportunities in deep-water areas. To this end, in 2010 new tax and investment incentives were introduced by the government particularly under Petroleum Income Tax Act 1967, with the aim to promote oil and natural gas exploration and development in the country's deepwater and marginal fields as well as promote energy efficiency measures and use of alternative energy sources. These fiscal incentives are part of the country's economic transformation program to leverage its resources and geographic location to be one of Asia's top energy players by 2020. Another key pillar in Malaysia's energy strategy is to become a regional oil and natural gas storage, trading, and development hub that will attract technical expertise and downstream services that can compete in Asia.

N.4.4.1 Evolution of the PSC Structure

Malaysia has awarded exploration acreage under a PSC structure since the Petroleum Act of 1974 transferred ownership of national oil and gas resources from state governments to Petronas. Since the early PSCs of 1976 there has been a continual series of adjustment to the PSC terms to encourage investment in both shallow and deepwater areas, culminating in the implementation of revenue over cost (R/C) PSCs which provide for faster cost recovery and a greater share of contractor profit oil during the early years of production. This has increased participation by IOCs with the number of awarded PSCs from 5 in 1998 to 83 by 2012 and Malaysia has since celebrated 100 active PSCs.

N.4.4.2 Fiscal Incentives to Stimulate E&P Activity

In 2010, to combat the declining production from mature fields, new tax and investments incentives were introduced to promote oil and natural gas exploration and encourage investment in the country’s upstream targeting:

- Rejuvenation of existing fields through Enhanced Oil Recovery (EOR),
- Development of marginal fields through innovative solutions, and
- Intensification of exploration activities.

These initiatives to increase oil and gas production contribute to the government’s ETP, which includes Malaysia’s oil, gas, and energy sector as one of its 12 National Key Economic Areas.

Broad fiscal incentives include:

- Reduction of tax rate from 38% to 25%;
- Accelerating capital allowance from 10 to 5 years;
- Waiver of the 10%exporting duty;
- Deductible investment allowance of 60-100%; and
- Allowance of the transfer of qualifying CAPEX between non-contiguous petroleum agreements within the same partnership or sole proprietorship.

Marginal oil fields form a significant component of Malaysia’s oil and gas reserves with the cumulative reserves in these small fields standing at about 580 million barrels of oil equivalent. The Risk Service Contracts (RSC) was introduced in early 2011 to stimulate development of these small and higher risk / lower return fields. The contracts share the risk between Petronas as the project owner and contractors as service providers. Under this structure the contractors recover development costs and are paid a fixed fee for services rendered, based on their performance during the development, execution and subsequent operation of the project. The structure protects contractors from the downside risk of unexpectedly poor reservoir performance by guaranteeing the return of invested capital.

N.4.4.3 Developing a National Energy Company

The Malaysian system requires participation by Petronas in every PSC. This has resulted in Petronas not only sharing in the value creation of field development but also acquiring significant knowledge and expertise in the development and processing of oil and gas. Petronas is now established as a significant international oil and gas company in its own right with operations around the globe including:

- Participation in LNG plants in Egypt (ELNG), in Australia (GLNG) and leading a project in Western Canada (Pacific NorthWest LNG).
- 2 Floating LNG projects under development in Malaysia.
- Participation in regasification terminals in the UK (Dragon LNG) and in Malaysia (Malacca LNG), also leading 2 other projects in Malaysia.
- Long-term LNG SPAs to lift its equity volumes (GLNG) but also with Qatar, Brunei, Norway and with the LNG aggregator ENGIE (formerly GDF Suez).

These positions will assist Petronas in meeting domestic LNG demand from its equity in domestic LNG production ventures and its international production portfolio. The requirement for participation by Petronas in all PSCs has allowed the government to develop a national oil and gas company which can now compete internationally with independent IOCs.

N.4.4.4 Gas Price Reform

Historically, the price of wellhead gas in Malaysia was based on medium sulphur fuel oil (MSFO) prices and has been set at 45% MSFO ex-Singapore for power generation in Peninsular Malaysia. Further down the supply chain, end-user gas prices are regulated by the government. Domestic gas supplies to Peninsular Malaysia have stagnated since June 2011 and are currently regulated at 13.70-18.35 ringgit (US$4.50-US$6.06/MMBtu), among the lowest-priced in Asia.

Malaysia has a 2016 target to raise domestic gas prices to international market levels. The government initiated a price reform in 2011 that was to raise the natural gas price every six months by $1/MMBtu. However, after an initial increase, prices remained constant until January 2014, when the government lowered the gas subsidy level and effectively raised the gas price for power users to $4.60/MMBtu. In May 2014, the government also raised the price for large non-power gas users (industrial and commercial sectors) to about $5.90/MMBtu.

N.4.4.5 Extending Exploration Zones

Malaysia has resolved several border disputes with neighbouring countries in recent years, e.g., through a 2009 agreement with Brunei and a 1979 agreement to form a Joint Development Area with Thailand. The 20-year dispute between Malaysia and Brunei over land and sea boundaries was eventually resolved in April 2009, with blocks being ceded to the other party. Since then, cooperation between both countries has strengthened. Since 2010, they have entered joint development agreement for bocks offshore Borneo.

N.4.5 Industry Response

N.4.5.1 E&P Activity

The fiscal incentives offered by Malaysia have attracted further interest in the area with nine new PSCs and two new RSCs awarded in 2012, bringing in five new upstream operators: Conoco Phillips, Inpex, Coastal Energy, PEXC O and RH PetroGas. In 2013 Petronas awarded four deepwater exploration licences offshore Sarawak, to companies including Shell, ConocoPhilipps and Murphy Oil and in December 2013 Malaysia celebrated 100 active PSCs.

Petronas has also awarded six RSCs since 2011 to interventional oil companies including Roc, Petrofac and Ophir petroleum. By mid-2014, three of these RSCs have commenced production of oil and natural gas.

N.4.5.2 Gas Price Reform

Although some progress has been made with reform gas price remains regulated in Malaysia, tension within the price control and subsidy system will increase as more internationally-priced LNG is used to supply the domestic market.

N.4.5.3 Border Disputes

A dispute remains with Indonesia over the Ambalat area between East Kalimantan and Sabah. The Ambalat area is thought to hold around 4.6 Tcf of gas resources, according to estimates by Indonesian authorities. Both Malaysia and Indonesia have allocated exploration blocks within the disputed area to oil firms. In 2005, Malaysia awarded the ND 6 and 7 blocks to Shell, while Indonesia had carved out the Ambalat and East Ambalat blocks from Block 14 to Eni and Chevron in 1999 and 2004 respectively. Although the nearby Bukat block (previously Block 13) held by Eni is not within the disputed zone, exploration there has also been hampered by the ongoing row. Tensions between Indonesia and Malaysia over Ambalat have eased recently and Indonesia's Energy and Mineral Resources Ministry and Malaysia's Geoscience Department have agreed to conduct mutual geological explorations between 2013 and 2015. However, this partnership is strictly limited to exchanging geological data and does not resolve the underlying border-related issues.

Further exploration initiatives particularly in the South China Sea must overcome territorial disputes with Indonesia, China, Vietnam and the Philippines. Upstream activity will remain dormant in other areas in the South China Sea as long as territorial maritime disputes remain unresolved; such as the Celebes Basin that borders Indonesia and Malaysia which remained underexplored because of competing territorial claims between the two countries (both awarded PSCs for the same areas).

N.4.6 Applicability to T&T

Malaysia offers some parallels with T&T in their efforts to adjust the fiscal regime in order to stimulate investment in the E&P sector and offset stagnating and declining production rates. Malaysia has gradually improved contractor terms under the PSC regime as greater levels of investment have become necessary to exploit remaining reserves. This has resulted in healthy growth in the level of participation in shallow water blocks and has encouraged the extension of the industry into deep water blocks.

In common with Brunei, Malaysia's energy policy has been developed as a component of an overall national development plan across the entire economy. The three themes for the E&P sector of rejuvenation of mature fields, support for development of marginal fields and stimulation of exploration activity are all as equally applicable to T&T as they are to Malaysia. A marked difference between the two countries has been the level of direct participation in the E&P industry by Petronas, which is a partner in all PSCs at a 15% equity level. This has allowed Petronas to develop in technical, operational and financial capability to become a recognised IOC in its own right.

The formulation of T&T's response to their declining R-P ratio should consider the positive industry response to Malaysia's improvements in PSC terms and other fiscal incentives, including sharing of cost recovery between PSCs. The participation by Petronas in every PSC provides a natural hedge to the relaxation of fiscal terms and has greatly assisted development of national capability in the E&P sector.

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