REPORT

DomGas Alliance Group

WA Midstream Gathering and Processing Review with Global Analogues

March, 2008

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Wood Mackenzie

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1. Review Study Objectives

The DomGas Alliance's (DGA) goals include increasing gas availability, connectivity and competitiveness for domestic gas end-users in Western Australia. One means of reaching achieving these goals is by enhancing gas resource connectivity and production in the Carnarvon Basin. The DGA seeks to explore opportunities to achieve these goals by encouraging and enabling greater transparency and efficiency in the gathering and processing of gas, which could possibly be facilitated by common use of such mid-stream facilities.

The DGA seek to better understanding international examples of common-use mid-stream gas gathering and processing facilities which have realized these goals of enhanced gas resource connectivity, production and competitiveness in other international gas sectors. The objective of this study is to understand how other regimes have evolved, and what the key criteria have been for enabling efficient, and timely, connection and production of gas resources.

The methodology employed for this study involved:

- Generating concepts to be investigated through an initial framing workshop with the DGA and Wood Mackenzie;
- Examining concepts identified and analogues for common use comparable mid-stream gas gathering and processing facilities globally;
- Understanding the evolution of these systems and the key criteria or events required for them to become utilized by multiple producers;
- Considering and evaluating synergies possible with common use facilities versus stand alone developments;
- Considering the applicability of other regimes to the Carnarvon Basin context;
- Considering jurisdictional, regulatory, and other issues which government and industry might have to address in applying such concepts in WA;
- Undertaking a work-shop with representatives of the DGA to review the analogues and history of other regimes, and to consider and explore related and new business models and legislation which would enable the DGA's goal. Measuring various solutions in terms of do-ability and attractiveness.

In this report, Wood Mackenzie provides a summary of the analysis and insight of other comparable global regimes which enjoy common use gas gathering and processing facilities. International analogues are reviewed including the history of how relevant regimes have evolved, and resulting benefits enjoyed. This report follows a summary slide presentation which was utilized to facility Workshops and summary findings.

2. Global Analogues

In this study, Wood Mackenzie considered internationally mature gas market systems where gathering and processing is undertaken in an open and competitive manner utilizing tolling and common use faculties. Wood Mackenzie's data base and analytical coverage are global. In order to narrow the focus to the most relevant regimes, Wood Mackenzie undertook to identify the three most relevant mid-stream regimes globally. For each of the selected regimes, Wood Mackenzie then undertook to provide a chronology of the regulation and effectiveness of these regimes, as well as the key factors which aided development of these regimes.

A summary is then provided highlighting what has worked and what has not worked to facilitate greater gas flows. In Wood Mackenzie's opinion, the three most relevant regimes are the US Gulf of Mexico, the UK, and Norway.

The follow section reports explore each of these mid-stream regimes:

2.1 Norway

Introduction

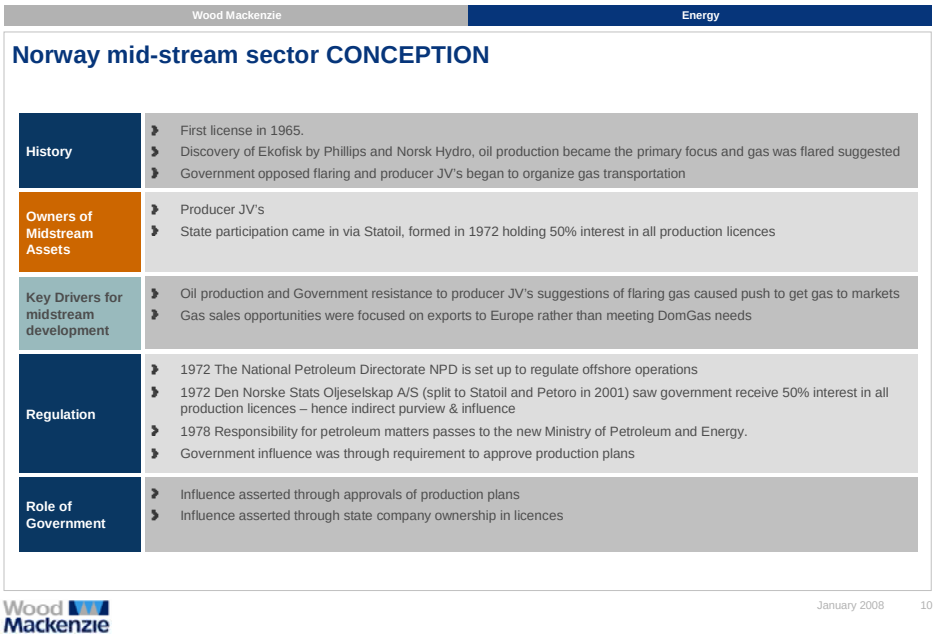
The first licensing round was held in 1965 between Norsk Hydro and Elf and six other French companies. At the time, attention was focused on the southern North Sea area, the impetus being the massive Groningen gas discovery in the Netherlands. However, the focus soon shifted to oil and the deeper waters of the central and northern North Sea, upon the discovery of Ekofisk. Ekofisk was developed by Phillips together with Norsk Hydro and the original licensees. The lack of transport opportunities to potential markets in the UK or continental Europe meant that the original production strategy proposed for the field was based on gas flaring. Although this approach was accepted on other continental shelves, the Norwegian authorities were strongly opposed to burning off these resources and began to examine potential landing sites. Gas transport from the Norwegian continental shelf was originally organised in various joint ventures.

From the beginning, Norway saw oil and natural gas as a national asset to be managed carefully. A generally healthy macroeconomic situation and near full employment meant that limiting inflation was a key concern. An additional aim was to ensure the development of a strong domestic industry. Initially there was no state involvement. Statoil, the state owned oil company, was formed in 1972 and held a 50% interest in all production licenses awarded after 1972 until 1993. Since then, and particularly since 1996, there has been a shift towards less state participation in licenses.

The continued growth of Norwegian production led to the signing of several significant sales agreements, such as Troll in 1986. Following this, the Norwegian government established a special Gas Negotiating Committee (GFU). Comprising Statoil, Hydro and Saga Petroleum[1], this body was given the job of co-coordinating sales under long-term contracts to the western European countries. The GFU negotiated contracts irrespective of the source of the gas. The Ministry of Petroleum and Energy then assigned production to fields to deliver the required contract quantities. Companies operating in Norwegian waters were represented on the Gas Supply Committee (FU), who met with the GFU to ensure efficient resource management. The aim was to develop Norway's fields in the most cost efficient basis possible.

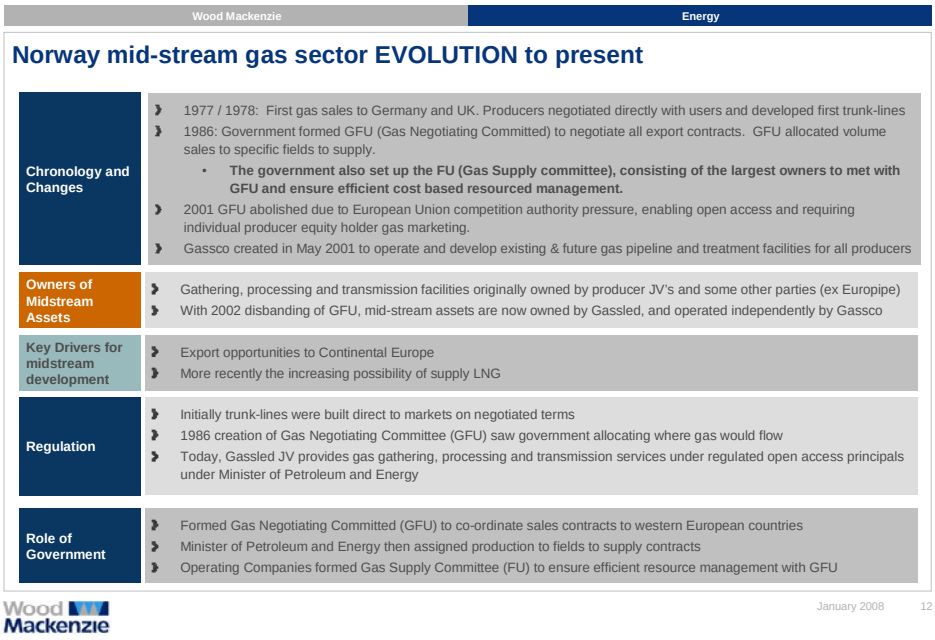
The following graphic summarizes the conception of the Norwegian midstream sector:

[1] Saga was acquired by Norsk Hydro in 1999



EVOLUTION:

The following slide summarizes the evolution of the gas mid-stream sector in Norway:



CURRENT SITUATION:

In June 2001, after sustained pressure from the European Union (EU) competition authorities and the threat of large fines to Statoil and Norsk Hydro, Norway abolished its centralised gas sales organisation (GFU). The European Union aimed to open the European market to competition by giving major gas companies and qualified buyers access to gas transmission and distribution pipelines, stores and liquefaction plants. The directive also specified that natural gas companies and buyers must have access to pipelines in the production system, including landfall pipelines from the NCS. As a member of the associated European Economic Area agreement, Norway was bound to comply. The EU attacked contractual arrangements originally agreed by the GFU on the grounds that they thwarted competition. Individual equity holders in gas-producing fields now have the responsibility for marketing and selling their own gas (Statoil Hydro sells the State's gas).

The break up of the old sales mechanisms led to the development of Gassco in May 2001, which effectively became the operator of the gas network on 1 January 2002. Gassco was established to operate the gas pipeline network and treatment facilities which serve all producers. Gassco's responsibilities can be split into three roles:

- **Operatorship.** As operator, Gassco is responsible for operating the Norwegian gas transport system on behalf of joint ventures/companies (owners).
- **Developing the gas transport system.** This covers Gassco's role in planning future pipelines and transport-related facilities (processing plants and receiving terminals).
- **Allocating infrastructure capacity.** Gassco allocates available capacity at any given time in the pipelines and transport-related facilities.

Regulated infrastructure

The Norwegian upstream pipeline network is the most extensive one in the world. 6600 km of pipelines are available to all producers of gas on the Norwegian continental shelf. Most of this network is now organised in a single ownership structure, Gassled JV, a joint venture between oil and gas companies on the Norwegian continental shelf. The gas flows from about 50 offshore production installations directly to the receiving terminals in Germany, France, Belgium and the UK, or to the onshore processing plants. Operationally, the integrated upstream pipeline network lays the basis for a considerable degree of flexibility. Gas flows from various sources can be optimised in the commingled stream to offer the right quality of Norwegian gas. This is accomplished by coordinating transport in the rich and dry gas pipelines, and in treatment plants and terminals. The flexibility of this infrastructure means that gas production can be varied to optimise oil recovery and the companies' individual gas sales portfolio. The Gassled partnership serves as the formal owner of the Norwegian gas transport infrastructure. It makes suggestions as to development of the network, which the owners then agree upon.

Access to the Gassled transportation system is given on non-discriminatory, objective and clear terms to all natural gas undertakings and eligible customers with a need for transportation. Standard Terms and Conditions apply to all holders of capacity. Gassco also provides an online service to manage booking requests and allocate primary market capacity within the Gassled system. Bookings for monthly and annual capacity requirements are taken twice a year, with short-term capacity available daily. Gassco also operates a secondary, inter-shipper capacity market. It introduced and an open system with tariffs to replace the former closed system. There are five separate tariff areas with an entry-exit principle for allocation, each having corresponding tariffs[2]. This ensures efficient operation of the upstream pipeline network and, in addition, flexibility for the shippers who may change exit or entry points if capacity is available. A government principle is that value creation

[2] Tariffs for the use of the upstream pipeline network are stipulated by regulation and are available at www.gasviagassled.no

should occur in the field and not in the transportation stage. Therefore transport is thoroughly regulated to prevent pipeline owners from earning an excessive profit through transport operation. The aim is to ensure that appropriate incentives are offered for exploration, field development and marginal production through the provision of regulated transportation costs and equal rights of access.

Non-regulated infrastructure

While the vast majority of the Norwegian pipeline system (particularly the export system) is regulated by Gassco, some additional infrastructure is operated on a joint venture basis. Access to this non-regulated infrastructure is by negotiation, with guidance by the MPE to what it considers as a reasonable rate of return that the owner of the pipeline system should apply.

The following slide summarizes the Norwegian gas infrastructure today:

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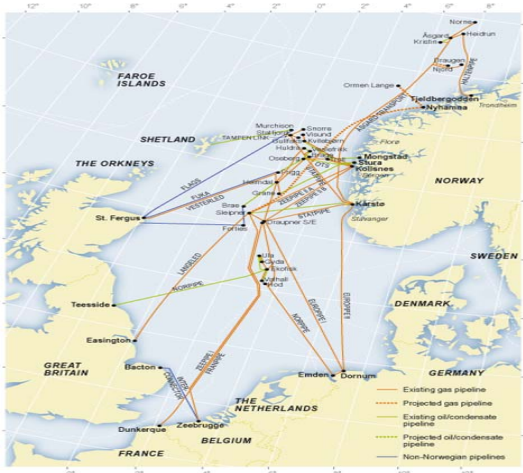
Norwegian mid-stream Gas Infrastructure today is regulated, open access and robust…

SCALE	6,600 km of off-shore pipeline 50+ off-shore locations
DRIVERS	98.5% Gas goes to Continental Europe: Germany, France, Belgium, UK
OWNERS	"Gassled JV" a partnership of NCS oil and gas companies
OPERATED	Gasso operates and develops Off-shore pipeline and gas processing Standard T&C's Non-discriminatory Zonal Tariffs Gas flows co-mingled to meet gas quality required



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CONCLUSIONS AND KEY POINT SUMMARY:

- Nearly all Norwegian gas is exported. An extensive pipeline network links Norwegian fields with four key markets. Gas can be transported through the network to different terminals, offering a degree of flexibility and security of supply. However it does mean that there is a greater reliance on certain key junction points than in the UK.
- Diversity of supply has been further increased through the potential to ship LNG to distant markets.
- The pipeline system is tightly regulated by Gassco, a state owned company. The company acts as a neutral provider of access for all companies wishing to use the gas network. Information regarding the network is provided equally to all shippers.
- Tariffs and terms of access are non-discriminatory and are set across the whole network, ensuring an even playing field. However there is little competing infrastructure and nearly no other route to market for gas except via the Gassled system.
- Gas sale contracts are now negotiated directly between the buyer and the field operator and this has served to strengthen the competitive nature of supply.

The following table summarizes the effectiveness of the current Norwegian mid-stream sector in satisfying the objectives of the DGA:

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Summary score card of Norway mid-stream sector structure

Diversity of Supply	50+ producers JV's , 10+ bcfd flowing Can ship to different terminals in Europe Multiple routes to markets – improves diversity and reliability
Competitiveness of Supply	Now very competitive: Previously centralized with one negotiator (GFU), but after 2001 was disbanded in lieu of individual equity owner gas marketing Gathering, processing and transmission to markets now at known and common tariffs = a level playing field
Lower threshold for entry of new suppliers	Yes. State now less involved in competing for licenses, allowing increasing diversity of supplier JV's Gathering and processing infrastructure on open access terms
Transparency	Gassco stated goal to work impartially to ensure system access Gassco is a neutral provider allowing common access to infrastructure Tariffs, Terms and Conditions are public and non-discriminatory
Gas on Gas competition	Working well as individual JV parties compete with others to sell into multiple markets Interconnectivity of system can also allows for continuance of gas flow via alternative route when segment constraints exist

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2.2 UK

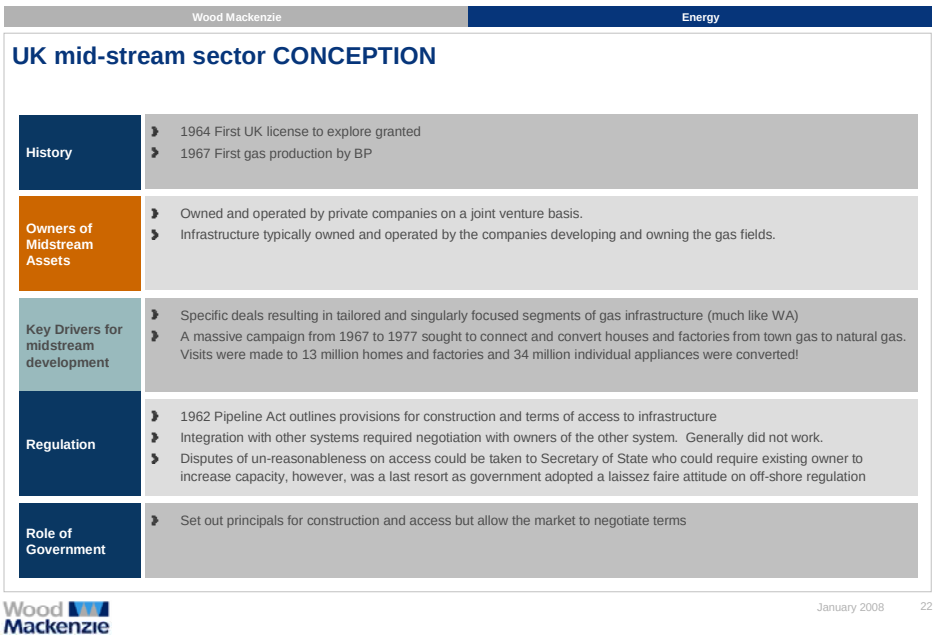
INTRODUCTION

The first licenses on the UK Continental Shelf were granted in 1964. The first gas field to go into production was West Sole in the southern North Sea in 1967, operated by BP. At the time the British government was preoccupied with a crippling balance of payments crisis and adopted a fast depletion policy. This meant that it moved to attract foreign companies and their expertise, with the aim of discovering and developing reserves as quickly as possible. The producers were put under enormous pressure to get oil and gas flowing quickly, with the result that UK production increased rapidly.

Offshore infrastructure (including terminals) in the UK were generally constructed, owned and operated on a joint venture basis by private companies, who in most circumstances were developing offshore natural gas fields. Over the course of the 40 years that the UKCS has been in production, an extensive network of offshore infrastructure has developed to bring natural gas to the beach. Construction of, and terms of access to, infrastructure is regulated by the Pipelines Act 1962. However, since pipeline systems were generally privately owned, licensees wishing to connect new pipelines into existing pipeline systems or to interconnect existing pipeline systems generally needed to negotiate contractual arrangements with the existing pipeline owners. Disputes could be brought before the Secretary of State, who could require an existing pipeline owner to increase capacity within a pipeline and undertake modifications. However this was generally seen as a last resort after negotiations had failed and overall the government adopted a relatively laissez faire attitude towards the regulation of the offshore industry.

The Conservative government of 1979-1997 pursued a policy of privatisation and liberalisation. As a consequence, the Government no longer has the ability to directly control the energy markets. As such, other than having an economic interest in the development of natural gas through the imposition of acreage rental, royalties and certain taxes, the State does not participate directly in natural gas production. The UK no longer has a State petroleum company, and natural gas development is carried out entirely by private companies or foreign State-owned companies under licenses granted by the Secretary of State.

The following slide summarizes the conception of the UK mid-stream sector:



EVOLUTION

Pipeline and terminal facilities

There are four main pipeline systems in the UK that carry natural gas from offshore platforms to coastal landing terminals:

- First, the Shearwater-Elgin Line (SEAL), operated by Total, transports gas from the Shearwater-Elgin area to the landing terminal at Bacton, England.
- Second, ExxonMobil operates the Scottish Area Gas Evacuation (SAGE), which transports associated natural gas from UKGS fields to the landing terminal at St. Fergus, Scotland.
- Third, the Central Area Transmission System (CATS), operated by BP, links fields in the Graben area of the UKCS to Teeside, England.
- Finally, Shell operates the Far North Liquids and Gas System (FLAGS) linking associated gas deposits in the Brent oil system with St. Fergus.

Overall, in the UKCS, there are currently 13 pipeline systems facilitating production export in the Central and Northern North Sea, and 25 pipeline systems serving the Southern Gas Basin and the Irish Sea.

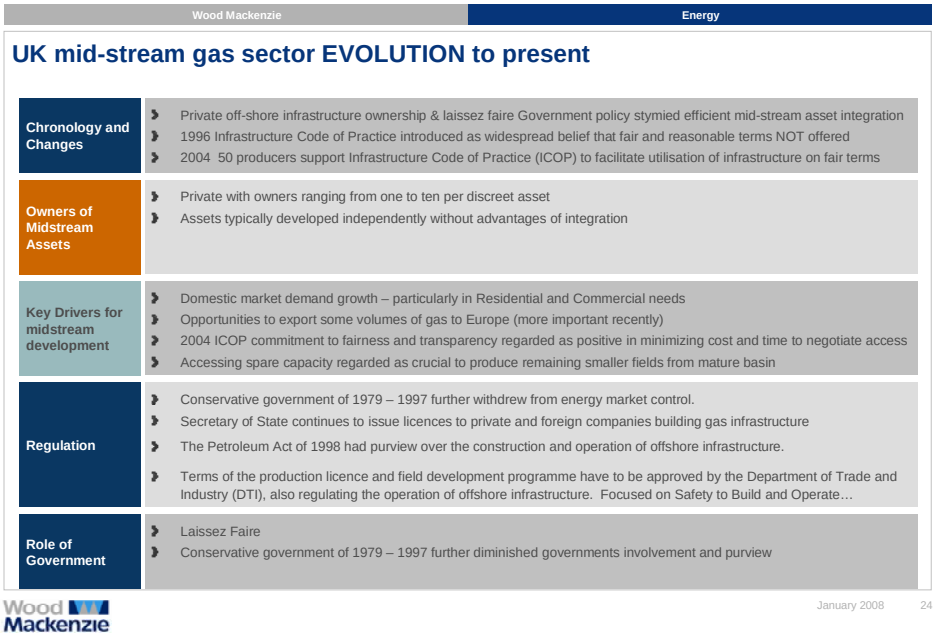
Great Britain has seven main onshore terminals which receive gas from the North Sea and other fields along with imported gas, these terminals are located at: St. Fergus, Easington, Theddlethorpe, Barrow, Bacton, Point of Ayr and Teesside. Gas pipelines have typically been built as discrete lines from offshore fields to the beach (i.e. the landing point at the UK shore). There are no offshore connections between pipelines, and therefore moving gas directly to alternative terminals is not an option at present. Ownership ranges from sole ownership by Total at the Total St Fergus terminal to over 10 owners at Sage St Fergus.

Key import and export infrastructure facilities

- As pipeline infrastructure spread across the Northern Sea, natural gas imports commenced in 1977 from the Norwegian part of the Frigg field in the Northern North Sea. Smaller fields in the vicinity of Frigg were tied in subsequently. Further gas imports commenced in 1985 from the Norwegian part of the Statfjord field.
- In 1992, the UK first commenced gas exports. UK volumes from the Markham field, which straddles the UK/Dutch median line, were transported through Dutch offshore infrastructure into continental markets. Volumes were, however, relatively small.
- Interconnector to Belgium – In early 1992, the Department of Energy brought together BP, British Gas, Conoco, Elf, Norsk Hydro and Statoil to study the idea of a cross-channel natural gas interconnector. It was originally conceived to be solely an export line and became operational in 1998. Import capacity was upgraded to 16.5 bcm in December 2005 and 23.5 bcm in October 2006.
- An export interconnector linking Scotland to Ireland was built in 1993 with an original capacity of 3 bcm, since raised to 6.6 bcm. Rapid demand growth in Ireland led to the construction of a second interconnector in 2002. An additional interconnector linking Scotland to Northern Ireland was constructed in 1996 with a capacity of 1.8 bcm.
- The BBL import pipeline from the Netherlands to the UK came on-stream in December 2006 with a capacity of 15 bcm.

- The Langeled pipeline, came on-stream in October 2007 (second leg) with a capacity of just under 30 bcm. The pipeline links the recently discovered Norwegian field, Ormen Lange, with the Easington terminal.
- Total import capacity is around 100 bcm.

The following summarizes the evolution of the UK midstream sector:



CURRENT SITUATION

Access to infrastructure is not regulated by government bodies such as Ofgem (the Office of Gas and Electricity Markets) or the DTI (Department of Trade and Industry). Instead, access is by negotiation between counter parties. As a consequence, the UK North Sea has developed with a variety of gas contract types and a complex ownership of reserves and infrastructure. This led to the widespread perception that fair and reasonable terms of access had not always been offered in a timely fashion. In response to this, an initial Infrastructure Code of Practice was introduced in 1996.

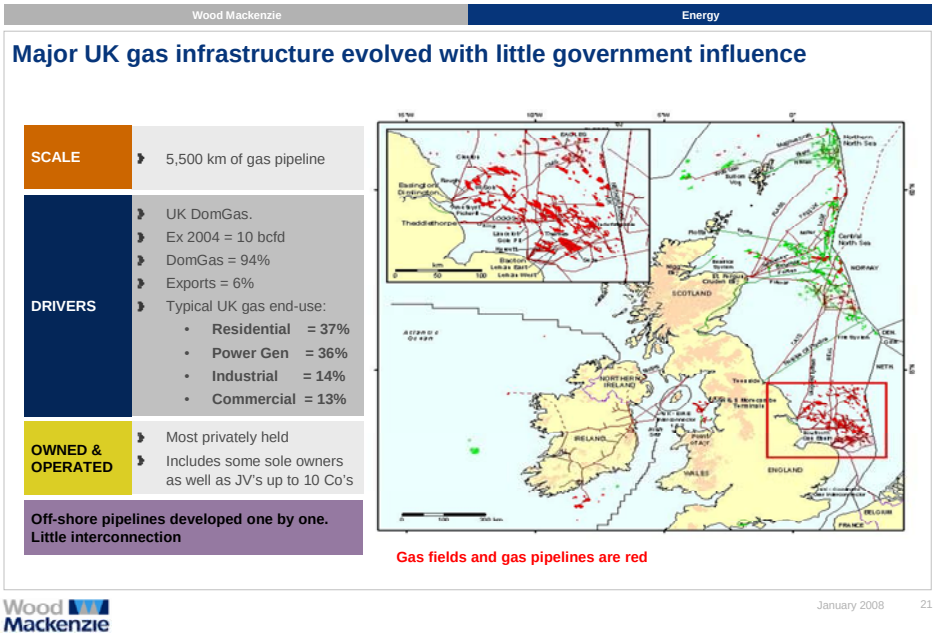
In 2004, over fifty North Sea oil and gas companies pledged their support for the re-launched Infrastructure Code of Practice (ICOP), which was designed to remove one of the prime obstacles believed to be hampering development of new UK oil and gas fields. Its purpose is to facilitate the utilisation of infrastructure for the development of remaining UKCS reserves through agreements for access on fair and reasonable terms, where risks are reflected by rewards. The Code applies to all infrastructure on the UK, Continental Shelf, onshore gas terminals and oil stabilisation facilities. By their endorsement of the Code, parties make a commitment to be guided by its principles and procedures, which aim to:

- Improve guidance
- Demonstrate fairness
- Increase transparency
- Assist in dispute resolution

The results were reviewed in 2006 by the United Kingdom Offshore Operators Association (UKOOA) and the survey confirmed a positive impact in several areas. For example, more high-level information on access, capacity, infrastructure availability, indicative tariffs, service levels and specifications is now available on a centralised website[3]. Additionally, more information on the terms and conditions of recently concluded deals is published. The UKOOA concluded that the code was helping to minimise the costs and time involved in negotiations.

Abiding by the Code should become more and more important as deals become more complex and the range of companies operating on the UK Continental Shelf becomes more diverse. Pooling or making spare capacity available to smaller fields is crucial, particularly when field-dedicated lines are not economically viable (e.g. West of Shetland, where small fields will be unable to support their own infrastructure).

The current UK midstream sector is summarized below:



[3] (www.ukdeal.co.uk).

CONCLUSIONS AND KEY POINT SUMMARY:

- Pipelines have been built as distinct lines, and as such gas cannot move to alternative terminals. This reduces security of supply since if one pipe or terminal goes down, there is no other route to market for the associated gas. For example in July 2007, the CATS pipeline shut after being hit by a ship's anchor. This pipeline system supplies about 20% of the UK's gas to the Teeside terminal. Field operators were unable to get their gas to market for two full months.
- Security of supply is growing all the time as an issue, as the UK is moving from being a net exporter to a net importer of gas. The UK will become increasingly dependent on Norwegian gas imports. The close vicinity of the UK and Norwegian gas networks means that the potential to tie-in Norwegian to UK infrastructure exists to facilitate imports.
- The Infrastructure Code of Practice (ICOP) should serve to improve access for new suppliers, since they will now have access to historical and current terms and conditions.
- While there is an increasing amount of information available in the public domain, there is still significantly less data available than in Norway, for example, with regards to capacity constraints and unplanned outages. This has been a frequent bone of contention with traders in the UK. For example, some terminal operators do not comment on day-to-day problems, leaving those terminal equity owners at an advantage in the market.
- There has been significant growth in recent years in gas-on-gas competition in the UK, particularly with the development of LNG regasification terminals and the coming on-stream of import pipelines such as the BBL and Langeled.

The current UK mid-stream sector in satisfying the objectives of the DGA:

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Summary score card of UK mid-stream sector structure

Diversity of Supply	Yes, however, most gas lines have been built point to point, allowing little redundancy • **2007 July CATS pipeline hit by ship anchor and 20% of UK's gas supply cut off for 2 months** UK now a net importer, increasingly dependent on Norwegian imports
Competitiveness of Supply	Competitive historically for decades due to oversupply of gas Recent years have seen seasonal spikes in gas prices during peak months Increased import pipeline capacity (2006/07) has seen gas prices lowered and winter spikes minimized LNG import capacity will also serve to keep gas supplies competitive between 1) indigenous, 2) import, and 3) LNG
Lower threshold for entry of new suppliers	Infrastructure Code of Practice (ICOP) should serve to lower the threshold for entry of new suppliers Still limited information available on capacity constraints due to independent facility operators
Transparency	ICOP has led to some transparency on gathering system access and costs Sometimes unclear information on key infrastructure capacity constraints due to private operatorship
Gas on Gas competition	Currently and prospectively looking to have achieved very strong gas on gas competition due to increased capacity in Norwegian pipeline import capacity, and LNG import capability UK gas pricing is indexed to the National Balancing Point (NBP) – a trading point much like Henry Hub with significant liquidity available to seller or buyers seeking to lock in short term prices

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2.3 US Gulf of Mexico

The current US Gulf of Mexico (GOM) midstream sector current comprises 23,000 kilometers of off-shore gas pipelines, connecting over 45,000 wells. Capacity of the off-shore GOM system is currently 20 bcfd, however, averages only approximately 9 bcfd. The following illustration captures the scale, drivers, and ownership structure of the current US GOM gathering systems:

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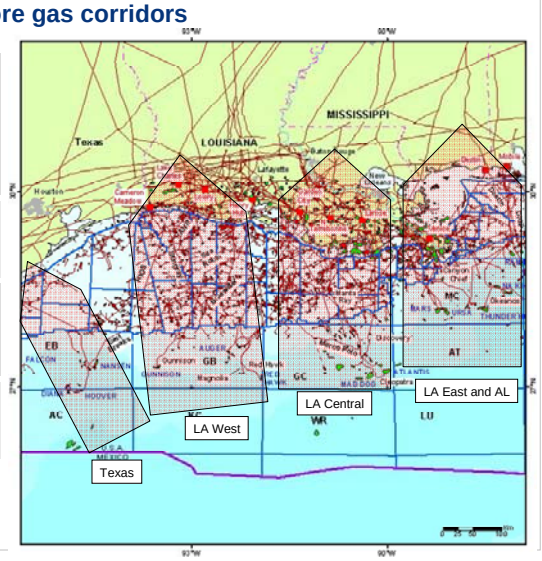
US Gulf of Mexico (GOM) off-shore gas corridors

SCALE	23,000 km off-shore gas pipes 157 companies operate Capacity to shore 20 bcfd Average throughput to shore 8-9 bcfd 45,000+ wells
DRIVERS	60+ bcfd US market Coastal Petrochem industry etc Coastal gas storage and Hubs
OWNED	48% interstate pipeline owned 5% pipeline affiliates 47% producers
OPERATED	Most off-shore pipelines and on-shore processing operated by owners: pipes and producers



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The US GOM midstream sector evolved under differing levels of regulation; initially highly regulated and evolving into completely private owned systems. The following two tables summarize how the GOM's midstream sector was conceived and evolved to present:

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US GOM mid-stream sector CONCEPTION

History	1940's off-shore gas discovered and production begins 1950's Minerals Management Service (MMS) awards first Outer Continental Shelf (OCS) acreage leases 1970's GOM production peaks at 16 bcfd
Owners of Midstream Assets	Primarily Gas Pipeline companies as they provided a "bundled service" to gas end-use buyers. • **End users effectively paid for pipelines and midstream assets to the well-head through regulated gas prices which recovered costs of pipelines as well as cost of gas under different dedication contracts**
Key Drivers for midstream development	WW II drove industry US gas demand substantially, which initially was served from on-shore sources. • **1950's opening of Outer Continental Shelf exploration leases** • **Resulted in GOM boom in 1950's and 1960's to fuel on-shore industry and pipeline needs** Producers were incentivised to develop reserves, or not, based on regulated prices within field dedication contracts
Regulation	Federal regulation was heavy from the 1930's for fear of Utility monopoly power. Transmission companies were primary gas buyers and final sales price was regulated, but allowing a rate of return on the pipeline assets • **1935 Federal Trade Commission regulated interstate pipelines** • **1938 Natural Gas Act regulated construction and transportation of natural gas across state lines which included off-shore** State regulation for in-state gas sales and infrastructure – making for a dichotomy of gas pricing as coastal industry grew
Role of Government	Facilitated exploration through allowing leases Controlled delivered costs by regulating pipelines (which also captured the cost to connect to off-shore gas)

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US GOM mid-stream gas sector EVOLUTION to present

Chronology and Changes	1973 Arab oil embargo, rising oil prices, and cold winters drove intrastate spot gas prices to $5 - $10/GJ while regulated interstate gas prices remained below $1.00/GJ. Gas shortage resulted 1978 Natural Gas Policy Act provided for phased deregulation of natural gas between 1979 – 1987 1985 FERC Order 436 caused pipelines to offer transportation services. 1992 FERC Order 636 ended pipeline gas retail and de-regulated gas gathering and processing
Owners of Midstream Assets	Ownership shifted from primarily pipelines to primarily producer owned gathering and processing facilities 1990's - some niche mid-stream unregulated "Field Services" companies entered the gathering and processing space The intrastate industry developed (1950s-1970s), and post Order 636 on intrastate side, producers have paid directly for a larger and larger % of G&P services, and obtained more control as a result.
Key Drivers for midstream development	Commercially driven negotiations resulted, rather than "all in the rate base" mentality of previous era Un-regulating mid-stream gathering allowed producers greater control, leading to more timely gas disposition accelerating oil production. Also ended the sometimes unworkable interstate pipeline flow allocations to off-shore producers • **Accelerated the exploration of deeper off continental shelf fields**
Regulation	1992 FERC Order 636 removed interstates from gas wholesale role, and de-regulated mid-stream gathering and processing • **Gathering and Processing unregulated. Commercially negotiated between producers and markets**
Role of Government	Initially allowed pipelines reasonable rates of return on assets yet while controlling consumer prices Over-time the flow on affect of pipeline capacity allocations to upstream producers caused limitations to oil and gas exploration. Activities increased after mid-stream de-regulation.

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The US GOM mid-stream sector has evolved into broadly interconnected system with significant surplus capacity to current gas flows. Much like the UK system which has also entered into a maturity as a gas basin, GOM producers have now have made efforts to bring greater transparency into their systems. These efforts have aided the connectivity and gas flow in a mature gas basin which would otherwise be facing declining flows on lower utilization of existing infrastructure.

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Summary score card of US GOM mid-stream sector structure

Diversity of Supply	Excellent. Includes numerous indigenous sources including conventional and non-conventional, as well as imported piped gas and more recently the re-establishment of four LNG receiving terminals. 5 new LNG terminals to be completed by 2010, and 2 new offshore LNG/gas off-loading buoys.
Competitiveness of Supply	Good gas on gas competition As demand has increased and indigenous supplies tightened, gas prices have risen, attracting LNG and piped imports
Lower threshold for entry of new suppliers	New suppliers can typically negotiate reasonably and promptly access to existing capacity Production in deep Gulf or in areas of no existing infrastructure will have approvals processes similar to Australia
Transparency	Moderately so. Off-shore gathering and on-shore processing facilities are unregulated and many are privately owned Many gathering and processing facility owners offer defined services for known stated fees Declining GOM production likely to result in competition where redundant alternatives exist, possibly lowering costs
Gas on Gas competition	Strong, yet more importantly, gas demand is likely to exceed gas supply in future years resulting in a seller market.

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2.4 Summary of All Three Regimes Reviewed

The following table summarizes all three mid-stream regimes reviewed in context of the key criteria

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Summary of current mid-stream analogues

	Norway	UK	US GOM
Owners of Midstream Assets	Gassled owns assets JV's by assets mostly producers	Private ownership JV's of mostly producers	Private ownership Producers, Pipeline Co's, independents
Key Drivers for Development	Exports UK & Europe (98%) Gas to shore, processed, then exported. Zonal system	DomGas (94%) Some exports (6%)	Abundant on-shore industry Unregulated gas price
Regulation of Mid-stream	Gassled regulated by Minister of Petroleum & Energy Open Access Terms	Mild. Dept Trade and Industry grant licenses to construct and operate. Not open access	None post 1992 Order 636
Role of Government	Initially controlled all sales, now regulates access	Laissez Faire	Initially fledged the industry by assuring cost recovery, later deregulated completely
Gas on Gas Competition	Good. JV members must market independently	Excellent. NBP Hub pricing DomGas, Import Pipes, & LNG	Excellent. Henry Hub pricing DomGas, Import Pipes, & LNG
Transparency	Excellent – regulated and transparent	Modest. 2004 Infrastructure Code of Practice, producers aid in capacity, rates etc.	Moderately so. Over capacity results in mid-stream players dealing
Barriers to entry	Few. Capital and regulated rates of return on facilities	ICOP helps. Declining supplies problematic	Low. Just need supply. Available capacity abundant

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3. Common Use Economics

This section explores the advantages which may be realized if off-shore gathering and processing facilities were built in a more integrated manner rather than in the traditional piece meal manner. It was important that the scenarios modeled by realistic to the Carnarvon basin. The DomGas Alliance Group was consulted on the volume and distance assumptions that should be considered. Contemporary Australian oil and gas analogues were then utilized to aid in the cost estimation of the various identified scenarios.

3.1 Size of Gas WA Gas Market

To determine the most relevant size of off-shore and gathering developments to be estimated and modeled, a realistic view of the size of the available gas market was needed. Towards this end, Wood Mackenzie and Energy Consulting Services estimates are summarized in the following graphic:

Wood Mackenzie | Energy

Common Use Metrics – What are appropriate considerations?...
1) Size of DomGas market…

- DomGas market available for new gas supplies

	Conservative	ECS
1. Current pent up demand (TJ/d 2007)	200	648
2. Market growth (TJ/d/a 2008 on)	50	
3. Contract expiration (50 TJ/d/a post 2012?)	50	245
Estimates of unsatisfied demand by 2013 TJ/d	600	893
+Annual Gas demand needs (Market growth + Contract expiration)	+100 TJ/d/a	+150 TJ/d/a

- Conclusion: Gathering and processing facilities of at least 300 mmcfd capacity are needed now followed by annual additions of 100 mmcfd/a
- Recommended Analysis – Illustrate Capital Efficiency possible for:
  - Three unique field developments (3 x 100 mmcfd), versus:
  - One initially oversized pipeline and processing plant (1 x 300 mmcfd), followed by two subsequent field tie-ins

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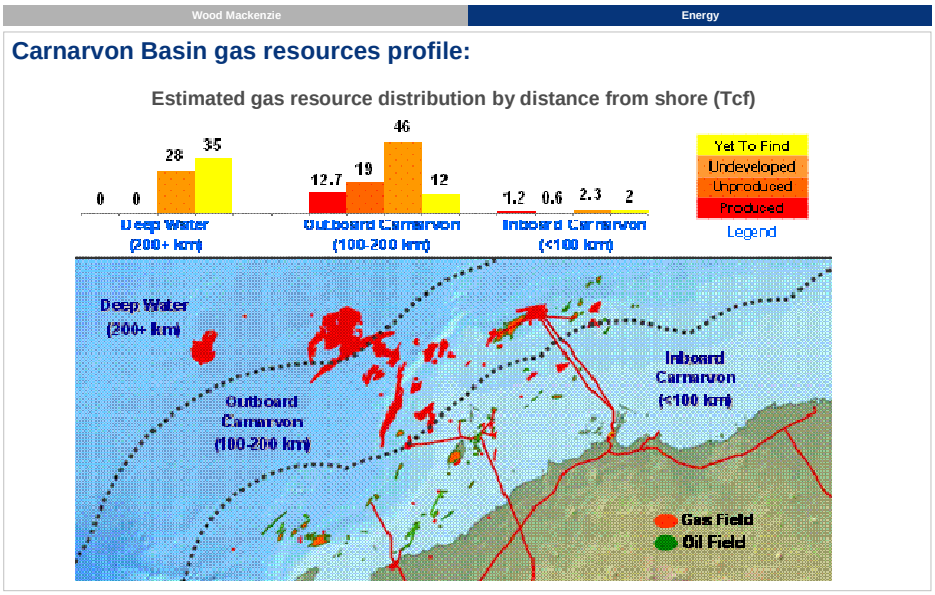
As a result of the above analysis, it was determined that gathering and processing facilities in the future will likely be needed on the scale of 100 TJ/d. Accordingly, our analysis sought to examine the synergies of building three separate 100 TJ/d gathering lines and processing plants, as opposed to one 300 TJ/d gathering trunk and processing plant.

3.2 Carnarvon Basin Gas Resource Distance to Shore

The distance to shore of the potential gas fields is important in order to estimate the likely gathering pipeline costs – which comprise a significant portion of the total project cost. The following graphic sourced from the DomGas Alliance Group and Woodside, summarizes the size and distance to shore of typical Carnarvon Basin gas fields.

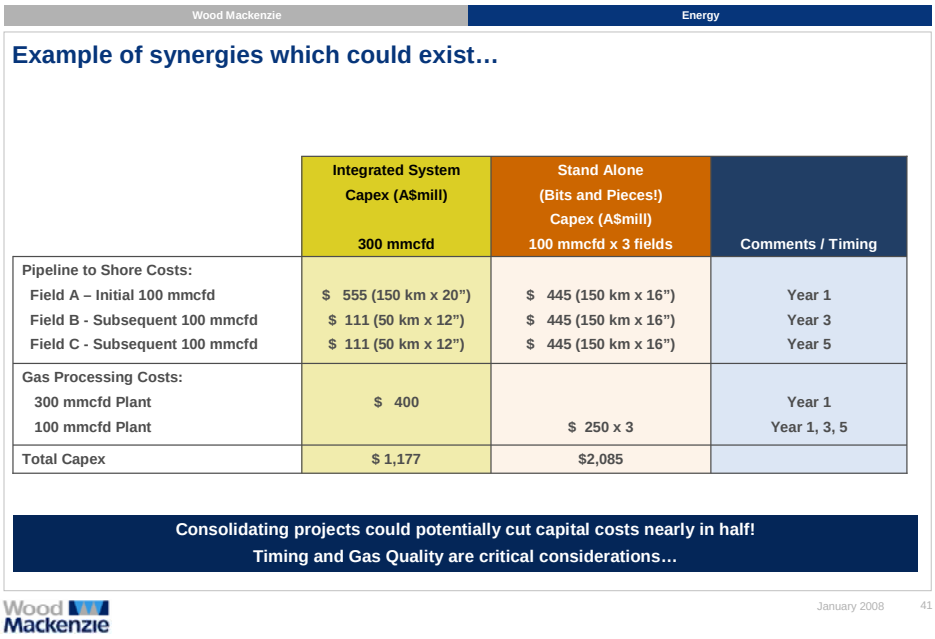


In considering the typical gas field distance to shore in the Carnarvon basin, it was determined that our analysis would be based upon gas resources which were 150 km from shore. The agreed reasonable and representative analysis would therefore look at two opposing development scenarios:

1) Three x 100 mmcfd developments;
    a. 3 x 150 km trunklines, and
    b. 3 x 100 mmcfd processing plants
2) One 300 mmcfd trunkline and processing plant;
    a. 1 x 150 km, 300 mmcfd trunkline
    b. 2 x 50 mmcfd, 100 mmcfd subsequent trunklines (tied in off-shore)
    c. 1 x 300 mmcfd on-shore processing plant

3.3 An Example Estimated Synergies Possible

The following table captures Wood Mackenzie's capital estimates of the two opposed development scenarios considered, i.e. three independent 100 mmcfd developments from 150 km off-shore, as well as one integrated development utilizing one common gathering trunkline and processing plant of 300 mmcfd capacity.

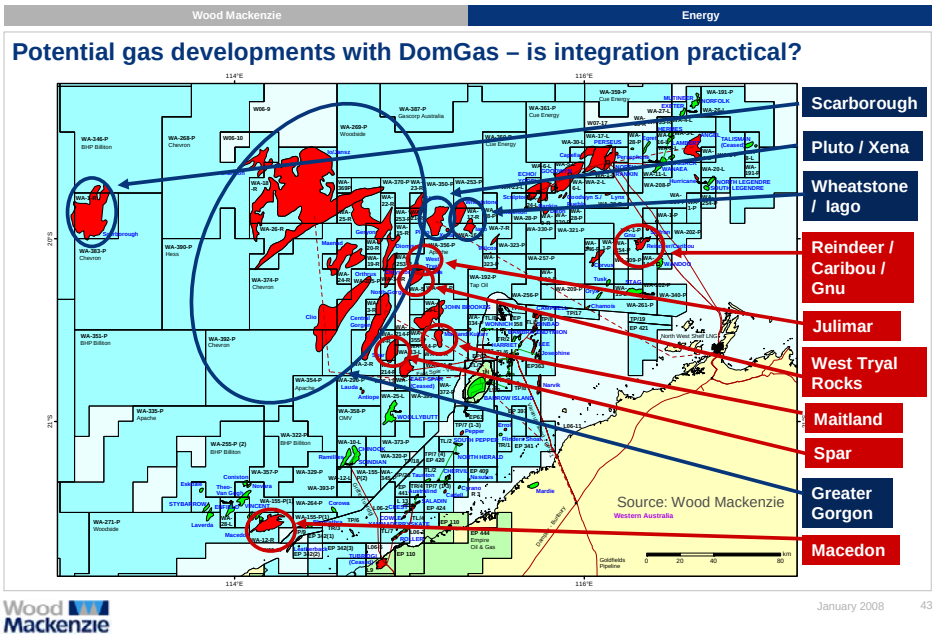


The conclusion of this hypothetical analysis was that by consolidating three independent developments of 100 mmcfd capacity into on common 300 mmcfd group of facilities, total capital savings could potentially be cut nearly in half.

Obviously, any realistic effort to combine different gas fields into common facilities would have to consider other pragmatic issues such as gas quality and operators intended timing to commercialize the resource. For example, gas fields comprising high condensate "sweet" gas could not practically be commingled with high CO2 or H2S gas (sour) fields. However, it is Wood Mackenzie's strong view that, in many cases, common facilities in the Carnarvon Basin could be utilized to gather and process gas, as has occurred on Varanus Island.

3.4 Potential Carnarvon Basin Field Consolidation

As can be seen in the following graphic, many of the known gas fields in the Carnarvon Basin are large enough and unique enough that they will necessarily should be developed independently of other fields – those fields are highlighted in blue on the following illustration.



Some integration opportunities do exist in the Carnarvon Basin and were identified as follows:

Known Gas Development Prospects	Potential for integration
Reindeer / Caribou / Gnu / Corvus	Plans for Devils Creek processing plant
Macedon, West Tryal Rocks	Gas quality issues
Julimar area, Maitland area, Spar	Potential gathering and processing hub
Pluto, Greater Gorgon	LNG Projects with DomGas commitments
Wheatstone / Iago, Scarborough	Potential stand-alone large gas developments

In summary, there are multiple fields that lend themselves to integrated development through shared infrastructure, such as Reindeer area, Julimar area, and Maitland /Spare areas. Some fields have clearly differing gas quality issues which will make for difficulties in sharing common infrastructure such as Macedon and West Tryal Rocks.

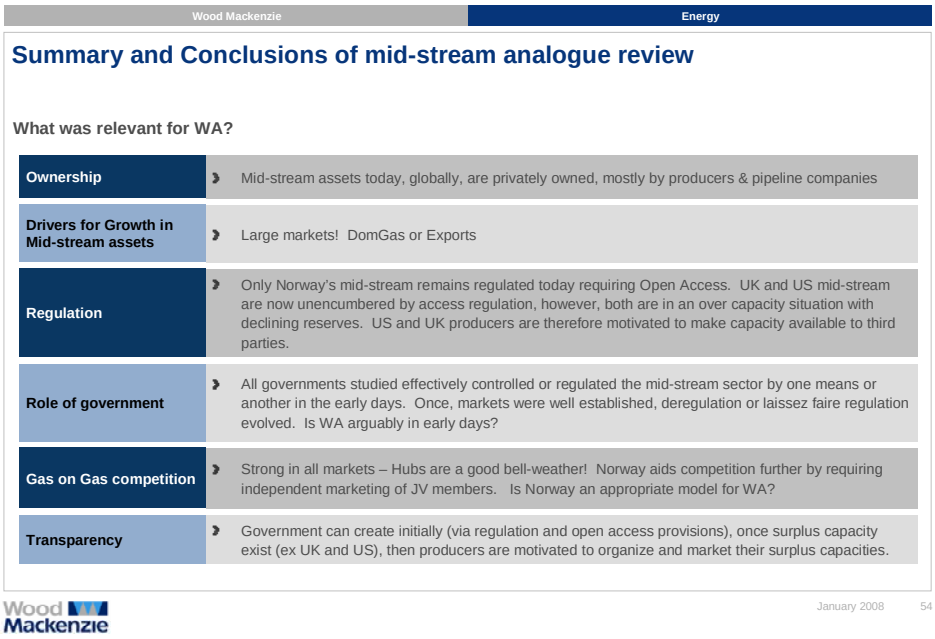
Integration of DomGas and LNG would likely provide some synergies, as well as challenges. Specifically, utilizing common facilities would usually realize economies of scale synergies, however, the pragmatics of administering differing tax and accounting treatment for a commingled stream may complicate matters. Furthermore, integrating fields into common facilities which have two differing potential sales markets may result in related gas suppliers seeking to sell only to the higher of the two markets. Additionally, commingling of gas streams for common gathering and processing would likely create challenges in scheduling and allocation of capacity in the event of curtailments. Finally, in the event of interruption of gas flow, the potential consequences (for example liquidated damages) may be vastly different between DomGas sales versus LNG sales.

4. Summary and Conclusions

From the analysis of the three global analogue regimes chosen, several conclusions can be made which are of some relevance to Western Australia as summarized below:

Midstream third party access: Third party access to mid-stream (gathering and processing) infrastructure has resulted in greater gas connectivity and gas flow. This is evidenced by Norway's regime where mid-stream regulation requiring open access terms now provides a flexible network with cost transparency. Norway's regime also seems to fit will with WA as the gas must in most instances first come to shore to be processed and then travel to markets which are typically a long distance away.

Midstream systems requiring negotiation with private owners are not ideal: The US and UK examples show that gas mid-stream infrastructure evolved mainly with arms length negotiations, and are not fully transparent. In the UK and US, transparency has resulted only after the regional area became very mature and the gathering assets were facing the prospects of declining use. Note both the US and the UK mid-stream sectors have capacities in excess of 10 bcfd. Western Australia currently sees off-shore gas flows of approximately 3 bcfd, arguably still a fledging production area. The following table summarized what was relevant for WA from the mid-stream analogue review:



Independent gas marketing within JV groups also appears to enhance gas flow: This has been the requirement in Norway, which is arguably the world most exemplary gathering regime if measured by the DomGas Alliance Groups objective criteria.

Integration opportunities do exist in the Carnarvon Basin: This study identified and mapped numerous examples where known gas fields have or will prospectively provide synergies. Integration opportunities are described in Section 3.4. In summary, the Reindeer, Julimar and Maitland/Spar areas could be synergistically combined. It should be acknowledged that Apache Energy's Varanus Island and proposed Devil's Creek project demonstrate good use of common hub facilities. The Varanus Island facility is near its capacity today, however, could likely accommodate additional gas post 2014 as John Brookes starts to decline.

Integration of DomGas and LNG would provide synergies: Gathering and processing synergies could obviously result if projects were combined, however, some challenges would result. Accounting and taxation treatments can differ depending on the location of the gas field and the ultimate market for the gas. These differences should be investigated and if possible aligned to ensure that producers are equally motivated from a tax treatment perspective.