FINAL REPORT

The Implications for Governance of the Distinctions Between Gas and Electricity

Submitted to

NGC
Wellington

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1. INTRODUCTION AND EXECUTIVE SUMMARY

1.1. INTRODUCTION

The Commerce Select Committee is currently considering the provisions of the Electricity and Gas Industries Bill. This Bill (among other things) establishes a "back-stop" regulatory regime for the gas industry, i.e., one that would come into effect if the industry does not establish a satisfactory self-governance regime. We describe the back-stop regulatory regime in more detail later in this report, but in brief, it provides powers for a renamed Energy Commission to recommend regulations for the gas wholesale market, gas transmission, gas distribution, and gas retail among other things. Although the wording of the provisions provides a degree of latitude for the Energy Commission to apply discretion in the arrangements it recommends, the provisions do reveal a potential for very detailed formal governance arrangements over an electricity-style spot market, and an active role in deciding who should expand transmission capacity and how it should be funded.

At the same time, the Commerce Commission is carrying out a price control inquiry in respect of gas transmission and gas distribution businesses.

For reasons that we expand on in this report, it appears to us that certain provisions of the Bill are based on an assumption that the gas and electricity industries "are the same" or are at least sufficiently alike to justify similar (and in some respects, shared) governance and regulatory regimes. While for some aspects of industry governance this may be a reasonable assumption, we do not believe that this is necessarily the case for other aspects. Rather, we consider that there are certain distinctions between the nature of gas and electricity, and particularly between the nature of the New Zealand gas and electricity industries, which imply that extreme care should be exercised before translating the electricity governance model and market arrangements to gas in New Zealand. The purpose of this report is to explore these distinctions and their implications for governance and regulation.

Following an executive summary, this report is structured as follows:

- In section 2, we briefly identify at a high level the reasons why governance is potentially important in network industries;
- In section 3, we briefly overview the proposed governance arrangements for the gas and electricity industries;
- In section 4, we compare and contrast the New Zealand gas industry with the New Zealand electricity industry and overseas gas markets;

- In section 5, we discuss the implications of differences between the fundamental nature of gas and electricity, and peculiarities of the New Zealand gas industry, for governance and regulation of the respective industries, with emphasis on the provisions of the Bill and the Commission's price control inquiry; and

- In Appendix A, we outline key aspects of the governance regimes for gas markets in Australia, the US and the UK.

1.2. Executive Summary

The New Zealand gas market is undergoing fundamental change with the rundown in the Maui field. Previously, the flexibility and size of the Maui gas field meant that management of the gas system was relatively simple. However, as the market moves towards a more diverse production base, safe, reliable and efficient management of the system will become more complicated.

In the shadow of the Maui decline, the gas industry is facing significant uncertainty, arising from matters such as the development prospects for Kupe, the possibility of LNG imports, the possibility of shutdown by Methanex, and climate change policies. As this uncertainty resolves itself, the industry will not remain static. Rather, the players and the industry can be expected to develop transaction-cost minimising arrangements in response to industry changes and any maturing of the market.

A key question for the industry and policymakers is the extent to which more formal and comprehensive governance arrangements, including any role for external decision-makers, is required to achieve efficient outcomes in light of these market changes and uncertainty. The Electricity and Gas Industries Bill provides broad ranging powers for an Energy Commission to recommend rules and regulations relating to a host of gas industry matters, in a manner that suggests significant intervention in private contractual arrangements, should the industry fail to put in place satisfactory self-governance arrangements. Although it is unclear what the Government would deem "satisfactory", in combination with the Government's objectives detailed in the "Government Policy Statement: Development of New Zealand's Gas Industry", it seems apparent that policymakers envisage arrangements developing that broadly mirror those about to be put in place for the electricity industry. In fact, the very first words of the explanatory note to the Bill state that:

> *The Bill applies a consistent framework to both the electricity and gas sectors with the objective of ensuring an integrated approach, cross-sector solutions, and achievement of the Government's policy goals.*

At the same time, the Commerce Commission is carrying out a price control inquiry in respect of gas transmission and distribution businesses. The depletion of the Maui field also has significant implications for the efficacy of regulation of these businesses: wholesale gas prices are rising, and customers are concerned about supply certainty. These factors are placing increasing competitive and revenue pressures on pipeline owners.

While, of course, there are some similarities in the nature of the gas and electricity supply chains (e.g. high levels of sunk costs, transmission infrastructure connecting suppliers to customers and long payback periods for infrastructure investments), it is not axiomatic that similar governance and regulatory arrangements are required. There are a number of fundamental differences in the nature of the gas and electricity markets that warrant careful consideration in the design of cost effective and efficient governance and regulatory arrangements for the respective industries.

Our overwhelming concern is that governance and regulatory mechanisms are proportionate to the issues confronting the gas industry, and do not inhibit the efficient evolution of it as the current uncertainty resolves itself. The gas market in New Zealand is extremely thin, and the small size of the New Zealand economy is likely to constrain the ultimate liquidity of it. Such a market will inevitably be dominated by long-term contracts that largely cover the positions of each market participant in the supply chain. The costs of elaborate trading mechanisms to deal with imbalances in pipeline capacity rights or injections or withdrawals outside of agreed contractual quantities must therefore be considered in light of the possible benefits, which may or may not emerge.

Furthermore, it is important that any intervention correctly identifies the forward-looking counterfactual and is shown to result in net benefits. If the price of gas continues to rise, the nature of the demand side may change, and regulation should not interfere with this by, e.g., inhibiting required investment in networks.

It is interesting to note the variety in governance models for gas markets around the world, and indeed the continuing evolution of these to fit market-specific circumstances. The New Zealand gas market is unique, and the governance and regulatory arrangements should reflect that.

In our view there are at least four differences between the New Zealand gas and electricity industries that warrant extreme caution before imposing governance and regulatory arrangements that may be appropriate for the New Zealand electricity industry onto the New Zealand gas industry:

- The New Zealand gas market is extremely thin and immature;
- Whereas electricity supply-demand balance must be coordinated in real-time within very narrow tolerances, we understand that gas supply-demand balances can be coordinated over a day in the New Zealand market;

- The electricity transmission grid is an interconnected grid, over which it is difficult to assign long-term property rights and identify beneficiaries of new investments. In contrast, property rights can be assigned to capacity of the largely point-to-point gas transmission grid; and

- While electricity provides an essential service, gas is a discretionary fuel, and pipelines cover a relatively small proportion of the country.

Taken together these factors imply that quite different governance and regulatory arrangements may be appropriate for gas to those that may be appropriate for electricity. In particular:

The Impact of Regulation

The discretionary nature of gas means that the case for regulation of firms providing gas services is weaker than is the case for electricity. Furthermore, the dynamic efficiency costs (i.e., impairments to efficient investment incentives) of gas regulation are potentially significant, given the:

- Relatively low coverage and penetration of gas; and

- The lack of any (implied) universal service requirement for gas.

In particular, regulation has the potential to impair incentives to invest in extensions to the existing gas network in order to connect new fields or new distribution areas of load. The key point is that regulation of a discretionary and immature fuel is a fundamentally different proposition from regulation of an essential and mature one.

Transmission System Expansion, Upgrades and Service Quality Improvements

There is a clear public policy concern with electricity transmission system investment. The major problem with electricity transmission is that because electrical flows cannot be controlled and the path that electricity takes in getting to a location is affected by all market participants' decisions, it is not possible (or at least it is difficult) to assign property rights to transmission capacity and exclude others from the benefits of an investment, particularly when the grid is interconnected. The result is likely to be under-investment in transmission from society's point of view, and some form of market or regulatory authority with coercive powers is generally created in an attempt to achieve efficient investment (e.g., the currently proposed Electricity Commission Establishment Unit Part F).

In contrast to electricity, the flow of gas across a network is controllable, by using valves. This makes the definition of property rights more tractable. The New Zealand gas transmission network is particularly simple compared to those overseas. In these circumstances, the investment incentive problems that face electricity are not likely to be an issue for gas transmission in New Zealand. Indeed, we observe property rights being defined in practice, and investment occurring.

In Appendix A to this report, we outline key aspects of the governance regimes for gas markets in Australia, the US and the UK. None of those regimes contains a regulatory power to require pipeline owners to invest. In our view, the provisions of the Electricity and Gas Industries Bill relating to transmission expansions, upgrades or supply quality are unnecessary, and in fact raise significant risks to future investment. We recommend that these provisions be deleted.

Wholesale Market Arrangements

The real-time delivery and quality requirements of electricity mean that a coordinating mechanism is always required, regardless of industry structure. With a vertically and horizontally disintegrated structure such as that in New Zealand, the formal, centralised spot market performs this coordinating role.

Although likely to get more complicated as Maui runs down and supply becomes more diverse, coordination of the New Zealand gas market is likely to be much simpler than coordination of the electricity market: the balancing issues are less pressing, and the transmission network is far simpler. Combined with the fact that the gas market is very thin, in these circumstances there should be no presumption that a formal, centralised spot market for gas along the lines of that operating in electricity would result in net benefits for New Zealand. Unfortunately it appears to us that the Bill makes this presumption, or at least could be read as such. In our view, the wording of the legislation should be more neutral and cautious about the shape of future governance arrangements for the gas wholesale market.

Network Access

The more controllable nature of gas makes it more practicable to separate access to the network and pricing of the commodity. While the ease of separation depends on the characteristics of the market in question, the fact that separation is practicable is a fundamental difference between gas and electricity and means that gas lends itself to a wider range of potentially efficient access arrangements, as we actually observe in New Zealand and overseas.

2. THE ROLE OF GOVERNANCE

All market transactions are underpinned by "governance" arrangements, whether:

- Explicit (e.g. with legally based contracts and enforcement mechanisms) or implicit (e.g. based on cultural norms and understandings); and
- Whether private (e.g., bilaterally or multilaterally negotiated contracts) or public (e.g., statute law such as the Commerce Act and the Fair Trading Act).

For most markets, bilateral contracts and generic laws can deliver efficient market outcomes, but in others, particularly those with network effects, more complicated and specific governance arrangements may be necessary to ensure that efficient market outcomes are achieved.

The electricity industry provides a good example. Electricity is characterised by:

- Externalities/difficulties in defining property rights (as described in more detail later in this report);
- Multiple parties, whose competing interests require real time coordination; and
- Relatively inelastic demand, raising potential market power concerns.

We discuss the importance of these characteristics for governance and regulation later in this report. At this point we simply note that these issues either do not exist, or at least are materially different in degree, for the New Zealand gas industry. Accordingly, it is likely that optimal governance arrangements for these industries will be different.

The need for an industry-specific governance arrangement is also dependent on market structure. For example, prior to the split of ECNZ, the coordination role between transmission and generation could be carried out internally within ECNZ. However, following the separation of generation and transmission (and the later split of retailing from distribution), explicit and independent governance arrangements were necessary to resolve natural commercial tensions between various market participants.

3. ELECTRICITY GOVERNANCE, AND THE PROPOSED REGIME FOR GAS

In light of the failure of the electricity industry governance proposal to attract sufficient industry and consumer support, the Government has acted to put in place governance arrangements for the electricity industry. The detailed proposal now before the industry is largely based on the technical arrangements that exist currently and covers multilateral contractual issues relating to:

- Wholesale market arrangements based on a mandatory pool, including market information disclosure requirements and arrangements for clearing, reconciliation, prudential requirements and settlement of the wholesale market;
- Common quality arrangements for access to the electricity system;
- Metering arrangements;
- Transitional arrangements from the NZEM and MARIA arrangements and dispensations;
- Arrangements for scrutinizing transmission investment requirements, Transpower investment proposals, transmission pricing methodologies and service quality obligations; and
- Customer switching protocols for the retail market.

In essence, the majority of interactions between market participants will be governed by a comprehensive set of rules specifying the rights and responsibilities of each market participant.

As we noted earlier, although the Government Policy Statement and the Electricity and Gas Industries Bill remain relatively silent on the precise nature of the market arrangements envisaged to manage the gas supply chain, it does appear that the legislation envisages governance arrangements for the gas industry that are similar to those in the electricity industry. For example, clause 43C(2) states that the purpose of regulations are:

> "Wholesale gas market
>
> (a) providing for the establishment and operation of wholesale markets for gas, including for ---
>
> (i) protocols and standards for reconciling and balancing gas:
>
> (ii) clearing, settling, and reconciling market transactions:

(iii) the provision and disclosure of data and other market information:

(iv) minimum prudential standards of market participation:

(v) minimum standards of market conduct:

(vi) arrangements relating to outages and other security of supply contingencies:

"Processing facilities

(b) setting reasonable terms and conditions for access to, and use of, gas processing facilities where ---

(i) this is reasonably necessary to allow new fields to be developed; and

(ii) spare capacity is available or could be made available if the person accessing or using the facilities paid the reasonable costs (including the costs of capital) of providing the capacity:

"Transmission and distribution of gas

(c) prescribing reasonable terms and conditions for access to, transmission and distribution pipelines:

(d) requiring expansions, upgrades, or service quality improvements to gas transmission pipelines including specifying how these will be paid for.

With respect to both the powers relating to the *wholesale gas market* and *transmission and distribution of gas*, the Bill appears to contemplate an industry-wide set of arrangements that would include all market participants and provide for mandatory rules, as with electricity governance arrangements. This would be a significant departure from existing market arrangements where trading is principally bilateral.

However, we do note that, where transaction costs would be reduced by implementing multilateral arrangements, the industry has done so, e.g. for system outages (known as the National Gas Outage Contingency Plan), third party access to pipelines (the New Zealand Gas Pipeline Access Code), and reconciliation through the Reconciliation Code.

4. NEW ZEALAND'S GAS INDUSTRY IN CONTEXT

4.1. INTRODUCTION

The purpose of this section is to compare the New Zealand gas industry to gas industries in Australia, the US and the UK, and to compare the New Zealand gas industry to the New Zealand electricity industry. Key conclusions are that:

- The New Zealand gas industry is very small, thin and immature when compared to both overseas gas industries and the New Zealand electricity industry; and

- The New Zealand gas transmission system is a simple point-to-point one with low coverage, compared to the more interconnected and extensive systems overseas and in New Zealand electricity.

4.2. NEW ZEALAND GAS MARKET COMPARED TO OVERSEAS

The New Zealand market for natural gas has a number of important distinctions from overseas markets. Compared to other countries, New Zealand has a relatively small number of gas buyers, a relatively small number of suppliers, a point-to-point pipeline grid, no gas storage (apart from linepack) and no formal gas brokers.[1] These factors, taken together, make the New Zealand gas industry quite distinct from that in other western countries.

4.2.1. Density of Supply and Demand

New Zealand has exceptionally thin markets in terms of the number of buyers and sellers in comparison to gas markets overseas, particularly the US and UK.

Table 1: Comparison of New Zealand With Other Countries

	No. Customers	Number of Suppliers
New Zealand	240,000[2]	Producers: 8 Transmission: 2 companies Distribution: 5 companies

1 Brokers provide supply and/or demand intermediary services, as well as bundled supply packages. We note that some firms, such as NGC, do undertake a less formal, aggregation role.

2 This is an estimate based on the most recent information disclosures (235,000), allowing for some estimated growth.

	No. Customers	Number of Suppliers
Australia	3,400,000	Producers: 12[3] Transmission: 8 major companies Distribution: 8 major companies Retailing: 9 major retailers
UK	20,990,000[4]	50 production companies
US	60M residential consumers[5] 5M commercial consumers[6] 235,000 industrial consumers[7]	8,000 producers; 1,600 distributors[8]

When establishing a trading market, scale and "thickness" matter for two reasons:

- The efficiency (e.g., as to price discovery) of a market is related to liquidity. Liquidity improves with the number of competing buyers and sellers, and volumes and frequency of trades; and
- Formal market mechanisms are costly to establish, and a proportion of these costs are fixed. Accordingly, there are economies of scale and the per trade costs may be prohibitive for an illiquid market.

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3 Department of the Environment and Heritage Australia (2003), *Proposed Management of Natural Gas - Discussion Paper*, November, Attachment 1, pp. 2-4. Available from http://www.deh.gov.au/atmosphere/natural-gas/paper-7/pubs/attachment-1.pdf.

4 Digest of UK Energy Statistics 2003, p. 101.

5 http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/historical_natural_gas_annual/current/pdf/table_17.pdf

6 http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/historical_natural_gas_annual/current/pdf/table_18.pdf

7 http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/historical_natural_gas_annual/current/pdf/table_19.pdf

8 Short, C., Heaney, A. and K. Burns (2002), *Australian Gas Markets: Moving Toward Maturity*, Australian Bureau of Agricultural and Resource Economics (ABARE) eReport 03.23 Prepared for the Australian Gas Association, Canberra, December, p. 23.

Even if the New Zealand gas market is too thin to support the cost of a formal market, coordination between market participants is still important. A coordination mechanism has been established and works as follows:

- Contractual imbalances: resolved *ex post* according to predefined contractual terms; and
- Security of supply: the system operator (NGC) detects gas imbalances in the system and will either bring on additional production or seek load curtailment.[9]

These coordination mechanisms have been effective in the simple market that has existed up to now. However, as Maui declines and the diversity of suppliers increases, more sophisticated means of coordination may be required. We discuss the role this changing circumstance implies for governance and regulation in section 5.

4.2.2. Transmission

Mature gas markets are really two markets:

- The commodity gas market; and
- The transport market.[10]

New Zealand is thin in both markets. New Zealand has two transmission networks, with a total length of 2,600 kilometres, which is far shorter than the countries surveyed overseas. These transmission networks are:[11]

- The Maui pipeline, which runs from the Oaonui processing plant to Huntly. The Maui pipeline is owned by Maui Development Ltd (MDL), which in turn is owned by Shell, Todd and OMV. This pipeline currently transmits only gas to be sold under the Maui contract; and
- The NGC transmission pipelines. These comprise approximately 2,300 km of transmission pipelines, which essentially cover many of the cities and towns of the North Island.

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9 NGC monitors security in both NGC and Maui pipelines.

10 Short, C., Heaney, A. and K. Burns (2002), *Australian Gas Markets: Moving Toward Maturity*, Australian Bureau of Agricultural and Resource Economics (ABARE) eReport 03.23 Prepared for the Australian Gas Association, Canberra, December, p. 2.

11 There are other small transmission pipelines that connect specific fields to industrial and petrochemical loads, and various distribution networks. The distribution networks are operated by NGC, Vector, Powerco, Wanganui Gas and Nova. We understand that the four main distribution companies (i.e., those excluding Nova) all offer open access common carriage to retailers.

These networks are primarily point-to-point.[12] Though relatively simple to define in terms of capacity, point-to-point networks limit the benefits of gas trading because of physical restrictions on the direction of gas flows.

A visual comparison of the New Zealand transmission network compared with that of the US quickly highlights the vast differences in scale and complexity (see Figure 1 and Figure 2). Gas transmission in the UK and Victoria is also distinct from New Zealand because of size and the interconnected structure (rather than point-to-point).

4.2.3. Brokers

We understand that there are no firms in New Zealand performing a formal gas broking role, although Contact Energy and NGC have performed an aggregating role by purchasing gas from a number of fields and using the gas for their own consumption or for resale to retailers and end-users. NGC, for example is undertaking a "gas gathering" initiative, which provides an intermediary service between gas producers and end-use customers.

12 See Figure 1.

Figure 1: New Zealand Gas Transmission Network

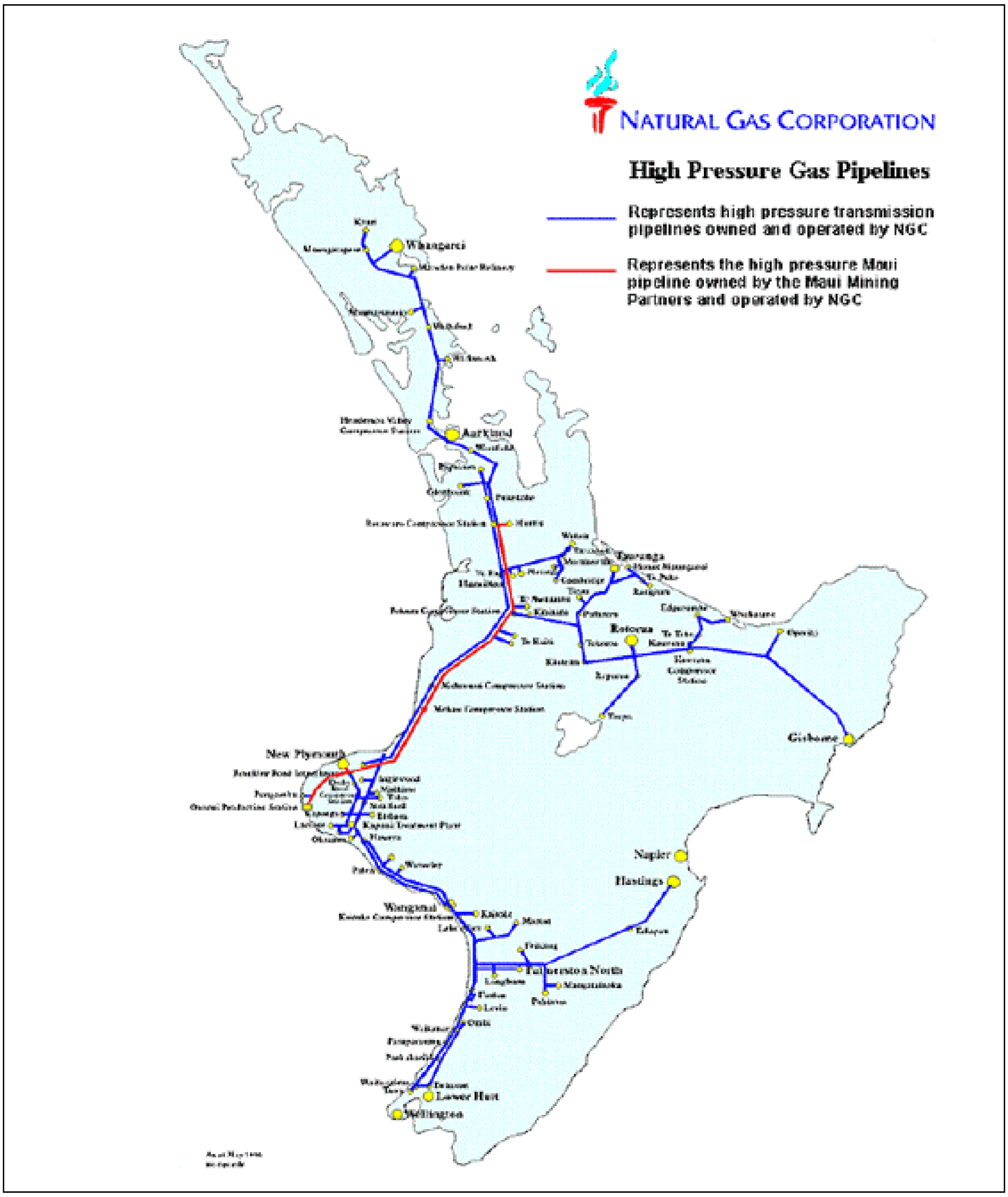
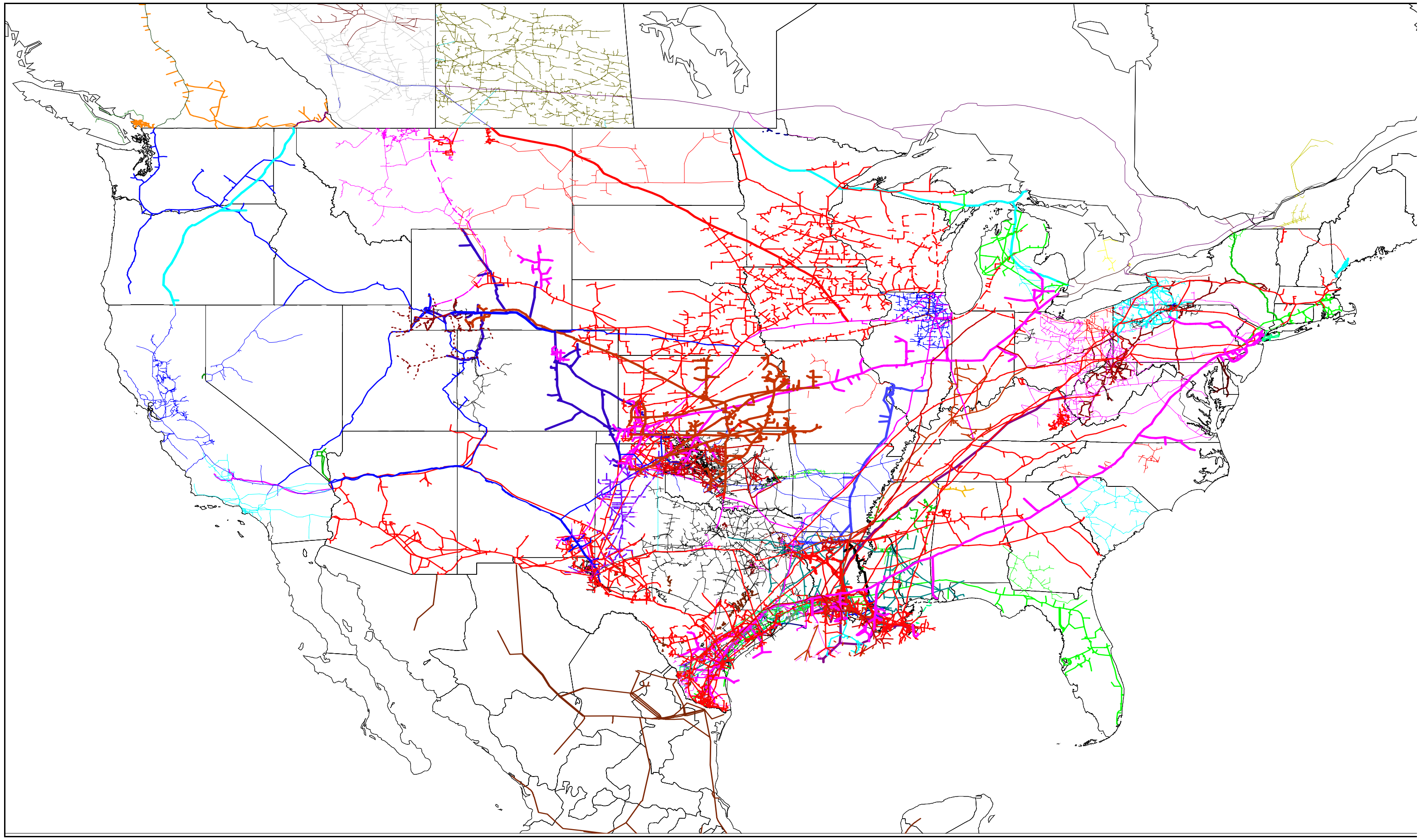


Figure 2: US Gas Transmission Network



4.3. COMPARISON TO THE NEW ZEALAND ELECTRICITY INDUSTRY

In comparison to the New Zealand gas markets already described, the New Zealand electricity industry has greater density or "thickness" of both supply and demand. Other distinctions between the markets are readily observable: the availability of instant-on generation capacity which closely mimics the dynamics of storage, the nature of electricity as a "fundamental necessity" with no feasible substitute for most end users, the size and structure of the transmission network, and the uses for which electricity is put by consumer type. We set out each of these differences in detail (and we discuss other distinction later in this report).

Table 2: Gas And Electricity Comparison

	New Zealand	
	Gas	Electricity
No. Customers	240,000[13]	1,731,769
Number of Suppliers	8 producers; 5 distributors	16 (4 main) generating co's; 30 distribution co's
Length of pipeline system (transmission and distribution)	2,600km	151,761km
Complexity of pipeline system	Primarily point to point	Interconnected. Many injection points and many off-take points. Subject to complex loop flow in certain locations.
Storage	Limited	No
Short term and spot market	No formal market, but some trades	Yes – formal market
Annual production	233.2 PJ[14]	135.4 PJ[15]
Residential[16]	3% (7 PJ)	35% (47 PJ)

13 This is an estimate based on the most recent information disclosures (235,000), allowing for some estimated growth.

14 Source: Ministry of Economic Development (2002), *Energy Data File 2002*, Figure E.2. Net gas production after deductions for reinjection, LPG extracted, flaring and own use.

15 Source: Ministry of Economic Development (2002), *Energy Data File 2002*, Table G.4.

	New Zealand	
	Gas	Electricity
Commercial	4% (10 PJ)	21% (28 PJ)
Industrial (including petrochemical and thermal generation)	93% (226 PJ)[17]	44% (60 PJ)

4.3.1. Producer and Consumer Density

The demand side of the New Zealand gas production market is very thin. The key players include Contact Energy, Genesis, Methanex, NGC, Nova, Ballance and potentially certain other industrials and co-generators. On the supply side, the gas production market is also very narrow. Current producers include Shell, Todd, NZOG, Swift, Austral Pacific (formerly Indo Pacific), Greymouth Petroleum, Westech and OMV.

4.3.2. Transmission

Even if there were a significant number of producers and consumers in the gas production market, the development of liquid trading would depend on the ability to transport gas between those players. As we have described, the gas networks in New Zealand are very long and thin, and significantly less extensive than the electricity networks.

There are important differences in complexity between gas and electricity transmission. The New Zealand gas network can be described as a point-to-point system. The electricity transmission network, however, is more complex and has the potential to suffer loop flow problems.[18] In practice, this means that it is very difficult to assign property rights in a looped electricity network because users can affect the quality and quantity of electricity of other users on the network. Furthermore, these externalities can be very difficult to anticipate in advance.

The New Zealand gas network is less susceptible to these problems for two reasons. First, valves can be used to control the flow of gas more precisely. Second, the mostly point-to-point nature of the New Zealand network minimises complexities.

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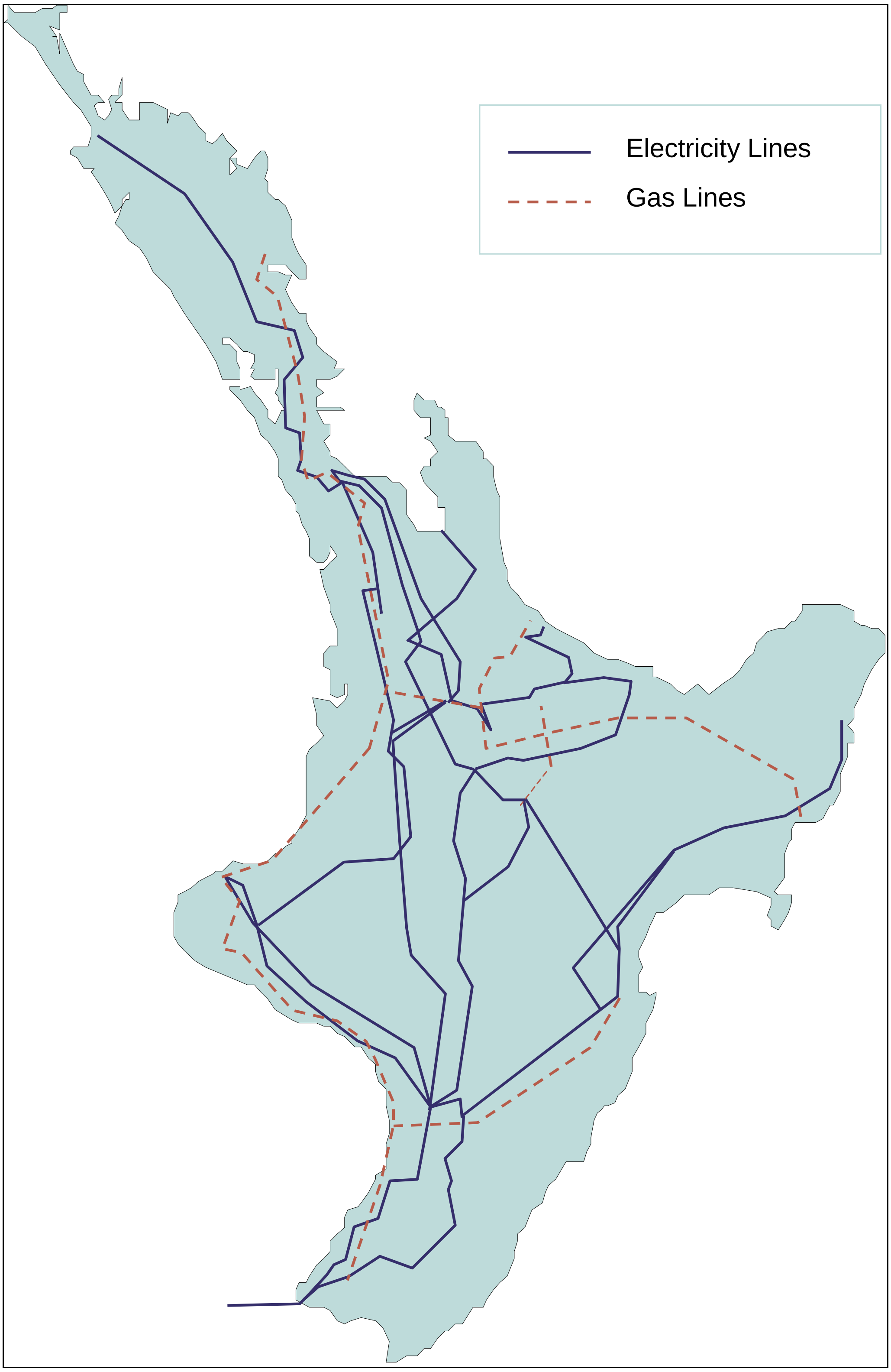
16 Residential, commercial and industrial statistics from Source: Ministry of Economic Development (2002), *Energy Data File 2002*, Chart G.7c.

17 Outside of petrochemical and electricity generation use only 24 PJ are used in other industrial applications.

18 We recognise, however, that the New Zealand electricity network is considerably less complex than many electricity transmission networks overseas.

Figure 3: North Island Gas And Electricity Transmission



4.3.3. Storage

While storage of electricity is technically possible (e.g., via fuel cell technology), as a practical matter and on a material scale it tends to be extremely, and possibly prohibitively, costly. It is not economic to produce electricity, store it, and use it at a later point to supplement other sources of supply. While hydro storage and the ability for production to ramp up almost instantaneously provides an element of storage, the storage does not provide additional system capacity.

In contrast, gas can be produced from a field and then stored for later use. Gas may be stored in a depleted field, in a storage facility (as LNG), or as line pack in pressurised transmission and distribution lines. The distinction from electricity is that the storage provides additional system capacity to meet peak or higher rates of demand without increasing field production in the short-term.

In the New Zealand market, the only storage capacity available is in line-pack.[19] Historically, balancing and maintaining system security could be managed with a combination of Maui production flexibility and line pack, but in future line-pack will be the principal means of maintaining system security. Tighter market arrangements will be required to manage security, but options will still exist for arrangements ranging from a centralised spot market to less centralised trading arrangements.

Table 3: Comparison of Storage Capacity By Country

Country	Capacity of Underground Storage / Annual Consumption
United States/Canada	20%
United Kingdom	3%
Australia	6%
New Zealand	0%

Source: ABARE p. 12.

19 Line pack provides a very valuable balancing role, allowing temporary mismatches in injections and withdrawals, which thereby permit a range of market mechanisms to bring injections and withdrawals back into line. Natural gas can technically be stored in depleted reservoirs. However, we understand appropriate reservoirs do not exist in New Zealand, and that, while Maui may be technically viable as a storage facility following its depletion, it would not be economically viable. We understand the costs of operating the offshore platform and creating the required pressure for re-injection would make using Maui as a storage facility prohibitively expensive.

4.3.4. Electricity and Gas as Necessities

Electricity is much more widely used than gas by residential and commercial users, as shown in Table 2. Furthermore, electricity is indispensable for most consumers in a range of applications.[20]

Gas, on the other hand, has a ready substitute for many users. For example, gas generation plants can be converted to alternative fuels such as coal or diesel, and residential and commercial consumers who use gas for heating can generally substitute to electricity or LPG. However, the reverse position is not true: it is self-evident that gas cannot be substituted for electricity in many important applications.

The effect of these differences, other things being equal, is to make demand for electricity less elastic than for gas. This has important implications for the design, and applicability, of regulation. We return to this topic later in this report.

4.4. Conclusion: New Zealand Market Circumstances

The New Zealand gas market by any metric is very thin, and given the size of the New Zealand economy is unlikely to be liquid in the foreseeable future. There are few production fields and few purchasers of gas. As a result, many of the features that have developed in other markets, such as gas brokering, spot markets, gas storage, and diverse pipeline systems, have not emerged to any significant extent. In part this has been driven by the dominance and flexibility of the Maui field to meet sizeable variations in demand at low cost, but the small size of the New Zealand economy must also act as a constraint. Further, given the likely increase in gas prices as Maui supplies diminish, there is a highly uncertain outlook for gas demand, with Methanex possibly exiting the New Zealand market, but its demand potentially being replaced by new CCGT generators over time.

The thinness of the New Zealand market has therefore led to market arrangements where long-term contracting and vertical integration cover risk positions in each of the functional levels and manage the overall costs of supply. In developing market arrangements to deal with a more diverse and less flexible production base, it will be important that such arrangements are cost effective and proportionate to the small size and likely thinness of the market.

In the next section we discuss the implications of market thinness and distinctions between electricity and gas for governance and regulatory arrangements.

20 In fact, it could be stated that electricity is indispensable for all consumers, as all firms must use electricity for some inputs, even if just lighting, etc.

5. DISTINCTIONS BETWEEN GAS AND ELECTRICITY, AND THE IMPLICATIONS FOR GOVERNANCE

5.1. Introduction

As noted earlier in this report, the gas and electricity industries do share some similar characteristics, e.g., sunk investment and scale economies in networks. However, there are also some very important distinctions, some of which are inherent to the nature of gas and electricity (e.g., the controllability of flows over a network), and some of which are peculiar to the New Zealand environment and economy. In our view, at least some of these distinctions have implications for governance of the industries.

In this section, we describe these distinctions and analyse their implications for governance and regulation.

5.2. Network Flows and the Implications for Investment

A feature of any interconnected (loop) electricity system is that energy fed into one point of the transmission grid is not limited to following any particular path of the grid to reach a particular load, by virtue of its natural propensity to flow along the path of least resistance (a consequence of Kirchoff's laws). Every injection into, and off-take from, the grid potentially affects electrical flows at every point on that grid, and it is therefore difficult to precisely define property rights over such flows. As Wilson notes:[21]

> *The flow aspect means that a property right cannot be assigned by title. No one owns electricity* per se*; rather, qualified market participants obtain privileges to inject or withdraw power from the transmission grid at specific locations.*

Because of the physics of the movement of electricity across the network, there is generally no meaningful direct physical relationship between a specific generator and a specific customer. Rather, there is a "common pool" of electric energy, and the aggregate generation of electricity and the consumption of electricity must be balanced continuously for the entire network to meet crucial physical constraints (frequency, voltage, stability) on network operations. As a consequence, a coordinating role is required to respond to sudden demand or supply shocks and transmission constraints, e.g., by bringing on reserve capacity or demand response. As Hogan (1999) notes (page 8):

21 Robert Wilson (1999) *Market Architecture*, draft paper, page 2.

> *Given the strong and complex interactions in electric networks, current technology with a free-flowing transmission grid dictates the need for a system operator that coordinates use of the transmission system.*

We return to this coordination role later in this report.

Electricity network investments give rise to externalities and related network investment problems. The absence of an ability to specify a strong set of property rights and exclude non-investors from the benefits of a transmission investment, suggests that a strong set of institutional arrangements is necessary to overcome free-riding and holdout problems in a decentralised transmission decision-making environment. Although market arrangements are in use in some countries (for example, financial transmission rights (FTRs)), which allow transmission investors to receive financial rights that may hedge a transmission position, these financial rights do not fund efficient investment.

Least cost dispatch in the New Zealand electricity market is determined taking into account the effect of both congestion and transmission losses on the value of injecting power at each generation location to meet demand. Generators receive signals about both congestion and transmission losses through the nodal pricing system, which provides a price at each location for an additional unit injected or withdrawn from the network.

Transmission losses increase with increasing amounts transmitted across a line. Over time the resulting price signals and relativities between nodes provide important information on the potential value of transmission investments to alleviate constraints or alternatively location for new generation and demand investments. So there is an important role played by the spot market in signalling the value (or costs) of locating at different parts of the electricity transmission grid. For example, electricity prices are generally lower in the South Island than the North Island because of surplus electricity generation relative to South Island loads. Nodal prices therefore signal that generation would be more highly valued in the North Island, or new loads would get cheaper power in the South Island.

Despite price signals emerging from the electricity spot pricing system, translation of those signals into actual investment is undermined by the difficulties of specifying property rights, meaning that investors generally find it difficult to appropriate the full benefits of their investments because of free-riding and hold-out. For example, consider a constrained line into a region that is causing prices in that region to be higher than elsewhere on the grid. Overall, the customers in that region would prefer that new transmission capacity be built if the cost of the incremental transmission capacity is less than the value released by reducing electricity costs. However, no market participant can be excluded from the benefits of any transmission investment, so even if current customers (i.e. retailers) could bind themselves to pay for the new investment, it would be impossible in the absence of regulatory force to exclude other retailers, who did not have to pay for the transmission investment, from entering and competing for customers. Although FTRs can be defined to protect the rights of those who do invest, it turns out that the market value of those FTRs will not be the total line cost and so will not fund the investment.

These problems with transmission investment (free-riding and hold-out) make it inefficient to rely on private transmission investment decision-making. Accordingly, institutional arrangements, such as the previously proposed industry Part F of the rulebook and the currently proposed ECEU Part F, are critical in ensuring that market imperfections do not derail efficient transmission investments, by allowing backstop decision-makers to determine necessary transmission investments and the market participants that should pay for them.

In contrast to electricity, by using valves, the flow of gas across a network is more controllable. This in turn makes the definition of property rights more tractable. Nevertheless, as a gas network becomes more interconnected and multi-directional, it is likely that property rights and allocations of gas flows will become harder to define, particularly given the non-coincident nature of injection and withdrawal. However, even in more complex interconnected markets rights to gas transmission capacity are assigned through contracts, known in the US as firm transportation service agreements, which may cover periods of 10-20 years.[22]

The more controllable nature of gas makes it more practicable to separate the access to the networks (discussed more fully in section 5.4 of this report) and the pricing of the commodity. While the ease of separation depends on the characteristics of the market in question, the fact that separation is practicable is a fundamental difference between gas and electricity and means that gas lends itself to a wider range of potentially efficient arrangements.

22 See ICF Consulting (2003) *Review of Overseas Gas Markets*, report to VENCorp.

Although nodal prices could also be generated in a gas spot market, a key distinction of gas transmission is that there are no physical losses[23] involved in transporting gas. Nodal prices therefore reflect either:

- Constraints in transmission capacity (caused by offtakes in excess of daily entitlements or excessive injections). Relative prices between nodes would therefore be determined by whatever it takes to clear each localised market; or

- Where no constraints exist, relative prices between nodes should in theory be linked by transmission costs, but in an illiquid market, dominated by few major participants, this may not occur.

As described above, the New Zealand gas network is essentially a point-to-point one, in contrast to the networks in Victoria, the US and the UK. Allocating property rights, identifying beneficiaries of investments, and the quantum of their benefit, is relatively simple in the New Zealand context. Accordingly, it is difficult to see that there are market imperfections that would prevent gas transmission investments from being made. This is illustrated by the relatively recent pipeline investment made to increase gas supply to Auckland, of which a certain portion of capacity was allocated to Otahuhu B and Southdown under long-term contracts. NGC's investment was underwritten by these long-term contracts with Contact Energy and Southdown.

As we understand it, the need for future gas transmission investment in New Zealand is likely to be driven by two factors.[24] The first is the potential for a new combined cycle gas turbine (CCGT) generator near Auckland (e.g., Otahuhu C). Current levels of transmission capacity would be insufficient to meet that new demand and so new transmission investment would be required. Under such circumstances, a pipeline provider (potentially NGC, the current Maui pipeline owners or a new transmission provider) would be willing to invest in new pipelines provided that the generator was willing to enter into a long term agreement to fund the investment (conceivably the generator could backwards integrate into pipeline ownership if it felt that the terms and conditions being offered were unreasonable).

23 Except for minor removals of gas for use in compressing gas in the high-pressure transmission pipelines and unaccounted for gas.

24 Although it is also quite possible that further investment in distribution networks will occur.

Clearly commercial issues will arise in such negotiations, but the specific problems facing electricity transmission of free-riding and hold-out are absent given the ability to define property rights over pipeline capacity, so any generator would be willing to commit to financing an expansion of capacity with *ex ante* certainty over access, terms and conditions. It is quite unclear what public policy concern would require intervention by a third party decision-maker (e.g., the Energy Commission) to mandate system expansion, or to identify beneficiaries of investments where these may be identified by contracts. Market power concerns should also be absent given that prior to investment in pipeline capacity or generation equipment both parties have options, e.g., the building of a new pipeline is a contestable activity.

The other potential requirement for transmission investment is in a greenfields development where a new gas field is discovered (e.g., North Island East Coast), where once again we would expect the pipeline to be underwritten by a long-term contract. Again it is unclear what market imperfections would result in a denial of transmission capacity. Moreover, given the need for further generation capacity in the electricity market, a gas producer would have the option of a shorter transmission pipeline to a local electricity generator, which exports electricity to the open access transmission system.

Overall, the key factor justifying intervention in electricity transmission investment decisions - absence of transmission property rights and therefore free-riding and holdout - is not present in the New Zealand gas transmission market. Therefore, externally mandated investment (as per clause 43C(2)(d) of the Bill) in transmission capacity is unwarranted. Conversely, overriding the rights of market participants to choose whether or not to make transmission investments introduces risks on pipeline owners that they will be forced to make investments that are not commercially sound, and/or at prices where they would not be able to recover their risk-adjusted costs. Transmission customers would potentially have perverse incentives to lobby for lower prices, or more favourable conditions.

More generally, regulation could have the effect of undermining efficient investment incentives. For example, when laying a new gas pipe, it may be socially optimal to build in excess capacity to cope with expected future demand growth. However, the prospect of, for example, that excess capacity being written down for regulatory asset valuation purposes, or new users being permitted access at incremental cost without proper consideration of option values, may deter investment. [25]

25 See Productivity Commission (2003) *Review of the Gas Access Regime* Productivity Commission Draft Report p109. A number of submitters had observed that gas pipelines had been undersized to avoid regulation, or minimise the risks that assets would be removed from the regulatory asset base because they may be considered "inefficiently" large.

Our recommendation is that in the absence of any inherent conditions that would lead to market failure, gas transmission investment decision-making should continue to be based on private decisions, and the provisions of the Bill relating to transmission expansions, upgrades or supply quality should be omitted.

5.3. Wholesale Market Distinctions

5.3.1. Introduction

In any gas or electricity wholesale market, we would expect to see simultaneous spot and longer-term contract transacting. However, the balance between spot and contract trading, and indeed the role of both types of trading, will vary depending on the:

- Depth and liquidity achieved in each market;
- Nature of the transmission system;
- Degree of coordination required; and
- Volatility of supply and demand.

In this section, we discuss the relevant issues. A key policy issue is to what degree a formal, centrally coordinated gas spot market should be promoted proactively in New Zealand, versus reliance on largely evolutionary developments that build on current arrangements. Because setting up a formal market would involve a material level of costs, an important question is whether the potential incremental benefits would justify these costs. The counterfactual should recognise that as the nature of demand and supply conditions in the industry change, we would expect the industry to adapt and to develop transaction cost-minimising governance arrangements, e.g., information revelation mechanisms.

While it is fairly uncontroversial that the incremental benefits of the formal New Zealand electricity spot market exceed the incremental costs of that market,[26] the calculus is less clear in the New Zealand gas market, for the reasons discussed in this section.

The purpose of the following discussion is to canvas relevant issues in order to assist the debate. We conclude by suggesting that certain clauses of the Electricity and Gas Industries Bill could be too presumptive about the potential net benefits of a formal gas spot market in New Zealand.

26 Although there may be debate about aspects of the detailed design.

5.3.2. The Role of Contracts

The role of long-term contracts in gas and electricity wholesale markets depends on the depth of those markets, and the volatility of supply and demand.

In a thin or illiquid market, long-term contracts perform three functions:[27]

- Management of hold-up risk in the presence of sunk investments;
- Management of quantity risk, e.g., the risk that Methanex will leave the New Zealand market; and
- Management of price risk.

As one moves from relatively thinner markets to relatively thicker markets (those in which the average transaction is small relative to the total volume transacted and the frequency of transactions in general is such that there is little time between one transaction and another transaction that might also have been made), the primary role of long-term contracts becomes increasingly focussed on the management of price risk. In the thickest markets, participants become far less concerned with the specific performance of a particular contract as there are numerous alternative sellers and buyers around.[28]

In electricity markets, the role of long-term contracts is essentially one of financial hedging, and "specific performance" is not important, as Hogan (1999) explains (pages 12 to 13):[29]

> *To achieve an efficient economic dispatch in the short-run, the dispatcher must have freedom in responding to the bids to decide which plants run and which are idle, independent of the provisions of long-term contracts. And with the complex network interactions, it is impossible to identify which generator is serving which customer …The short-term dispatch decisions by the system operator are made independent of and without any recognition of any long-term contracts. In this way, electricity is not like other commodities.*

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27 As well as longer-term price discovery.

28 Furthermore, the deeper and more sophisticated a wholesale market is, the more likely it is that other governing terms of transactions (e.g., quality and liability) will form part of the market rules rather than part of bilateral contractual terms.

29 William W Hogan (1999) *Market-Based Transmission Investments and Competitive Electricity Markets,* Center for Business and Government, John F Kennedy School of Government, Harvard University. See Paul L Joskow (2000) *Deregulation and Regulatory Reform in the U.S. Electric Power Sector*, revised draft of paper prepared for the Brookings-AEI Conference on Deregulation in Network Industries 9 to 10 December 1999 for a discussion of the "poolco versus bilateral contracts debate" in the context of electricity markets.

> *This dictate of the physical laws governing power flow on the transmission grid does not preclude long-term contracts, but it does change the essential character of the contracts. Rather than controlling the dispatch and the short-run market, long-term contracts focus on the problem of price volatility and provide a price hedge not by managing the flow of power but by managing the flow of money.*

Hedges are widely used in the New Zealand electricity wholesale market, primarily in the form of "contracts for differences" and vertical integration between generation and retail.

The New Zealand gas wholesale market is very thin. Without a sufficiently diverse group of sellers and buyers that can be organised into a more-or-less "common pool", specific performance is inherently and fundamentally important. For example, the Pohokura joint venture parties have indicated to the Commerce Commission that they would not choose to develop the Pohokura field without a long-term contract in order to mitigate potential hold-up risks. In contrast the focus of a new power station in New Zealand would be on managing price volatility rather than hold-up or quantity risk.

5.3.3. The Role of Spot Markets

Coordination

New Zealand's and many other electricity markets around the world are coordinated through a spot market dispatch process, whereby competing generators offer quantities of electricity into the market at various offering prices or price bands and a market and/or system operator dispatches the generating units accordingly, taking into account the requisite system security protocols including transmission system constraints and requirements for various ancillary services. Fundamentally, spot prices set for each trading period are based on the price(s) of the marginal generator(s). The advantage of a spot market trading mechanism is that it allows for the centralised coordination of a complex generation and transmission system, intended to ensure that quality standards are maintained in real time. Previously this coordination role was centralised within ECNZ (with cost-based dispatch). However, the spot market mechanism provides this coordinating mechanism in a vertically and horizontally disintegrated industry.

The real-time distinction is important to electricity - even momentary fluctuations in the voltage and frequency characteristics of electricity can have potentially disastrous consequences for system security, so a well-empowered system operator is critical to ensuring system stability. This is the case regardless of industry structure – even with the decentralised New Zealand structure this role needs to be centralised. The nature of electricity generation is also a defining feature relative to gas. Electricity producers may face changing costs of generation over even relatively short spaces of time - in part critically dependent on the availability of fuel supplies. For example, the value of water used to dispatch hydro plant in New Zealand varies quite frequently depending on expectations about a host of factors such as rainfall, storage and other changing supply and demand conditions. Furthermore, the relative size of each generation source is usually a relatively small percentage of total delivered electricity in each trading period, requiring a sophisticated coordination mechanism to bring in and out different sources of supply to meet changes in demand.

In summary, electricity spot markets play an important role in coordinating dispatch given the small size of individual generation, real-time quality issues, varying marginal costs of generation, fluctuations in demand and losses and constraints on the transmission system. Although demand-side bidding in most electricity markets has not yet reached any great level of sophistication, in principle it could also play an important role in achieving real-time balance. In practice demand-side participation has largely been limited to provision of interruptible loads to meet contingencies through the reserves market.

By itself the spot market is unlikely to underpin longer-term supply growth, since stable contracts are likely to be required to ensure that the price risks of buyers and sellers are managed. Nevertheless, the spot market provides important signals for the short-term management of the electricity system, including real-time maintenance of supply and demand, which could not otherwise be managed in a decentralised manner.

The role and nature of centralised coordination in a gas market cannot be deduced and/or generalised directly from experience in electricity markets. In electricity, irrespective of the commercial and structural arrangements for the industry, the need for a high degree of coordination of supply and demand balances in real-time is invariant across markets. In contrast the need for coordination in gas varies considerably with the nature of the system, including:

- The nature of the production fields (relative sizes, flexibility and contribution to total demand);

- The nature of the pipeline and storage system (the degree to which there are capacity constraints and more generally complexity, e.g., a single point to point pipeline has quite different requirements to a "meshed" network);[30] and

- Demand volatility.

Under previous New Zealand gas market circumstances where demand volatility could be met with increased Maui production (including over weeks and seasons) and the pipeline system was not constrained (as it still is not), a complex spot market, with balancing and reconciliation arrangements that were close to real-time, would not have obviously increased the level of market efficiency, since there was sufficient system flexibility to coordinate supply and demand balances over reasonably lengthy time periods. Consequently, the gas market in New Zealand has not historically required highly specialised market-based mechanisms to provide essential and timely signals to participants about value-added behaviours. Put differently, there has been little that participants needed by way of information that could not be provided using means and mechanisms that would surely seem quite casual if held up and compared to those required in the electricity market.

In the future, however, as Maui depletes and is replaced by smaller sources the gas market is likely to evolve to require capability for managing many smaller suppliers from a more diverse range of locations, although, in the absence of field developments outside the Taranaki region, it is likely that gas flows will continue to flow from the Taranaki region. Balancing requirements are likely to become more complex. However, it is far from clear that these requirements mean that a formal spot market is necessary. Rather, a lower cost and simpler mechanism may be quite appropriate.

In general, the degree to which a detailed spot market and sophisticated trading arrangements will be required for coordination purposes will depend in part on the "tightness" of the market. The more important consideration, however, is whether there is likely to be significant benefit from real-time signalling with respect to how changing circumstances should influence ongoing behaviours. There is no need, for example, to spend a lot of resources on systems that tell people what behaviours would be preferable to whatever it is that they currently do, if whatever it is that they currently do (however imperfect) is already easily managed (because, for example, of the relatively small number of players in the market). On the other hand, if different behaviours have significant cost or investment or operational or security implications, then it pays to invest in price discovery mechanisms that support the discovery of those price signals and their relatively more transparent transmission to market participants.

30 Also, identification of ownership becomes complicated when there are multiple injections and offtakes. Work is ongoing in Australia in the "non market" gas states on this issue - in order to facilitate retail competition in these states with no formal market.

If imbalances in injections and withdrawals have relatively few short-term implications for security of supply (and therefore externality effects), then arrangements can be relatively simple, whereas if the market is "tight" and more frequent interventions are required to keep the market balanced over the short-term, then more complex trading arrangements to enable financial contracts to better match the underlying physical requirements may be required which allow market participants to trade their way out of imbalance positions more efficiently.

A prominent example of a centralised "pool" gas market is the Victorian one, to which we return below. In contrast, the wholesale markets in the US and other Australian states are decentralised bilateral models.[31]

The other key element of the nodal pricing framework in the New Zealand electricity sector is that it provides locational signals about the impact of transmission constraints on the dispatch of electricity to meet loads throughout the transmission network. The need for locational signals on the gas transmission network is considerably less (at least at this point in time) because of its relative simplicity (i.e. point to point network) and lack of constraints. However, this may change in the future, for example, if significant new discoveries are made.

Price Discovery, Entry and Position Adjustment

Other potential roles of a gas spot market include:

- Price discovery, i.e., signalling the short-term value of gas;[32]
- Assisting entry by reducing the need for producers to have in place sales contracts to underwrite investment;[33]
- Enabling market participants to adjust their long-term positions; and
- Assisting the development of generic contracts for differences.

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31 See Short, C., Heaney, A. and K. Burns (2002), *Australian Gas Markets: Moving Toward Maturity*, Australian Bureau of Agricultural and Resource Economics (ABARE) eReport 03.23 Prepared for the Australian Gas Association, Canberra, December.

32 Longer-term price discovery is a function of longer-term contracts, forward markets, etc.

33 Although we note that, while a (liquid) spot market may, of itself, enable investment, it will generally be a complement to long-term contracts.

However, the ability of a market to efficiently carry out these roles will depend on the level of liquidity. As explained elsewhere in this report, liquidity is likely to be a problem for the New Zealand gas market, both now and into the foreseeable future. The Australian Bureau of Agricultural and Resource Economics appears to have a similar view of the prospects in Australia:[34]

> *Although it is difficult to know with any certainty how many participants are required for an active spot market, it would appear that with only three to five major suppliers and a demand side that is likely to comprise less than thirty participants there is little likelihood than an active transparent spot market in commodity gas could emerge in Australia in the short to medium term.*

A formal, centralised market may assist in the attainment of these roles to some degree, for example, by:

- Transparently aggregating all information on system supply and demand; and
- Lowering transaction costs of trading.

However, liquidity is ultimately a function of size and depth of the market and the New Zealand economy, and cannot be materially manufactured by the creation of a market.

5.3.4. Gas Markets in other Jurisdictions

In Appendix A to this report, we outline key aspects of the governance regimes for gas markets in Australia, the US and the UK. One of the interesting things to emerge from this survey is the variety in governance models for gas markets around the world, and indeed the continuing evolution of these to fit market-specific circumstances. For example:

- As discussed below, the Victorian spot market is of the "pool" model, while the US market is a "bilateral" one. Furthermore, the UK appears to have shifted from a pool model to more of a bilateral one; and
- Within Australia, there are differences in the retail market governance models between states. While the Victorian retail market is operated by the state-owned VENCorp, the New South Wales, South Australian and Western Australian models involve an industry-owned operator.

34 Short, C., Heaney, A. and K. Burns (2002), *Australian Gas Markets: Moving Toward Maturity*, Australian Bureau of Agricultural and Resource Economics (ABARE) eReport 03.23 Prepared for the Australian Gas Association, Canberra, December, page 10.

In Victoria, there is a strong similarity between the gas market governance arrangements, including a spot market, to those used for electricity.[35] A common entity, VENCorp, is responsible for both electricity and gas transmission networks and operation of the gas (but not electricity) market.

CRA has had significant involvement with that market development, starting from the basic philosophy and design, and consider that it has considerable promise as a model for future market developments in Australia and elsewhere. Still, it seems fair to say that the ultimate potential of that market design has yet to be fully proved. It is notable that there is a review of the balancing arrangements in train at the moment. The review is considering, among other matters, the potential for increased and more focussed intra-day and inter-locational pricing. At this stage, then, it seems fair to express some caution with respect to the extent to which such a development might prove worthwhile in the limited New Zealand context.

Initially the Victorian market was developed in a system environment not unlike New Zealand's, with supply coming almost entirely from a single physical source, through a single pipeline, to a fairly simple loop network serving the Melbourne region. Since that time the network has developed further, with greater diversity of supply (both pipelines and fields), and the addition of seasonal storage capacity, and it is partly this added complexity that has spurred consideration of further market refinements.

It is worth noting that establishment of such a market involves significant costs, and was undertaken in the light of possible future development both within Victoria, and increasingly between states in Australia. The situation in New Zealand is obviously rather different, and caution seems appropriate. In particular, the number of participants, and the potential volume of trading, must be a matter of concern.

In this respect, the Victorian experience may also be relevant. That market has been dominated by four major participants sharing the supply from one major source, under contracts which all derive from a single master contract, with volumes for each participant approximately matching requirements. Thus the market does not really represent the classic interaction between suppliers and consumers, but rather a marginal balancing interaction between participants for whom supply and demand is approximately in balance, and who must co-operate in various ways to share the same physical infrastructure. The gas is all drawn from the same source, at the same price, and under the same conditions. Under those circumstances it is probably not surprising that market prices track contract prices very closely, except when the system is under stress, and the prospect of non-supply forces prices up reflecting short term scarcity, but not necessarily sufficient in isolation to incentivise investment.

35 Although the Victorian gas spot market is a net market and the electricity spot market in Australia is a gross market.

The situation in New Zealand is obviously not identical, but the issue is, if stress situations only happen rarely, and contractual relationships dominate the system, whether this kind of market is really the most efficient way of coordinating the activities of a very small set of participants. Again, the conclusion may depend significantly on the prospects for further market developments. We face the dilemma that, while development of an open market may improve prospects for development of greater diversity and competition in the sector, compared with reliance on bilateral arrangements, the cost of that market development may just add a burden to the sector if, in any case, there really is little prospect for such developments to occur.

5.3.5. Implications for Governance of the New Zealand Gas Wholesale Market

It is apparent from the above discussion that the appropriate level of formalisation and centralisation of the New Zealand wholesale gas market is an open question, implying that policy makers need to tread very cautiously and carefully weigh up the costs and benefits of interventions. This is particularly so given that the counterfactual is not the status quo, but an uncertain future and an industry that can be expected to develop its own governance mechanisms to deal with the changing market circumstances.

There is, in fact, a broad spectrum of options and issues and one should not assume that the nature of an efficient wholesale market mechanism for gas would necessarily borrow much from its quite distant cousin in the electricity sector. In this regard, it appears to us that certain clauses in the Bill are either unfortunately and detrimentally loose in their use of the words “wholesale markets for gas” or inherently and inappropriately presumptive about the potential net benefits of a more formal and centralised market. For example, clause 43C(2)(a) states that a purpose of regulations is to provide:

> *for the establishment and operation of wholesale markets for gas …*

Similarly clause 43Q(1)(c) states that a function of the Energy Commission in relation to gas is to:

> *establish, operate, and facilitate the operation of … markets for gas industry participants …*

We would suggest that these clauses be softened slightly, e.g., by inserting the words, “if and to the extent appropriate”.

5.4. NETWORK ACCESS

In electricity transmission, access to the grid is based on the "common carriage" model. Market participants do not have physical capacity rights but may inject electricity and withdraw from the network according to a set of system protocols. A system operator coordinates resources in real time to ensure that security standards are met. Provided that a new entrant can certify compliance with performance requirements there are no other restrictions on accessing the transmission grid.

Access terms to the New Zealand electricity transmission grid are set out in Transpower's Pricing for Grid Connection Services (December 2003), which allocates costs to customers through direct connection charges, interconnection (HVAC and HVDC) charges and an economic value adjustment.

As noted earlier, the more controllable nature of gas makes it more practicable to separate access to the networks and pricing of the commodity. While the ease of separation depends on the characteristics of the market in question, the fact that separation is practical is a fundamental difference between gas and electricity and means that gas lends itself to a wider range of potentially efficient access arrangements. This is illustrated by the situation in New Zealand, where:

- NGC's transmission system is operated on a contract carriage model (as described in more detail below);
- When access to it becomes open, it is proposed that the Maui pipeline be operated on a common carriage model; and
- Distribution systems are operated on a common carriage model.[36]

NGC operates an open access transmission grid, with access allocated on the basis of contracted maximum daily quantities (one year standard term), with a throughput fee and penalty charges for imbalance positions. NGC has in place a number of transmission special deals that provide different arrangements according to customer preferences (e.g. for price certainty / length of contract). These special arrangements are available to all wholesalers/retailers on a non-discriminatory basis. Transmission customers on standard contracts are permitted to balance their capacity entitlements across locations, providing a significant amount of flexibility to manage demand volatility. NGC hosts a secondary market to net out capacity imbalance positions. Table 4 summarises recent trades. A given capacity transfer could apply for a period from one day to one year.[37]

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36 This is true for networks owned by NGC, Powerco, Wanganui Gas and Vector. Nova does not permit third party access to its network.

37 Source: NGC submission to the Commerce Commission "Submission in Respect of The Draft Framework Paper" 20 August 2003, p13.

Table 4: Capacity Transfers

	Y/E September 2001	Y/E September 2002	Up to July 2003
Intra-company capacity transfers	620	324	361
Inter-company capacity transfers	14	13	40

ACIL, in its report to MED,[38] considered that these access arrangements are satisfactory in the current environment, but could be a source of inefficiency in the post-Maui environment. In particular, arrangements may not be sufficiently flexible to allow for small market participants in future to manage their positions, and may not be capable of reflecting cost drivers or allow for injections outside Taranaki and Rotowaro. ACIL also suggested that harmonisation of access arrangements between the Maui and NGC pipelines would improve market efficiency.

It is likely that there will be some need to evolve the simple arrangements for gas pipeline access in the post-Maui environment. It is at this stage not clear what market arrangements will best meet requirements for flexibility, security of supply, and the revenue requirements of gas pipeline operators. While common carriage arrangements, similar to electricity transmission, are a potential means of managing pipeline access, it is not necessarily the case that common carriage would best meet the needs of market participants. Given the controllability of gas flows there are a wider range of access regimes possible for gas transmission, along a spectrum from common carriage to contract carriage. Appendix A outlines the regimes in Australia, the US and the UK.

5.5. OTHER DISTINCTIONS

There are a number of other distinguishing characteristics of gas relative to electricity that contribute to the proposition that gas and electricity governance arrangements need not be the same.

38 ACIL Consulting (2001) *Review of the New Zealand Gas Sector - A Report to the Ministry of Economic Development*. October.

5.5.1. Storage

Because of the storage difficulties discussed in section 4 of this report, electricity supply and demand must be matched in real-time by a system operator. Reserves and other ancillary services (such as voltage support) must be on standby to ensure that in the event of generator outage or major load curtailing that the system remains stable. Markets for reserves and contracted voltage support in the New Zealand market provide the necessary ancillary services to maintain system security.

In contrast, the arrangements for coordinating gas supply and demand can be relatively more flexible where there is storage capacity. In New Zealand storage is limited to line-pack, where changes in gas pressure within the pipelines can be used to manage imbalances in injections and withdrawals over a day. The amount of storage available in line-pack limits the timeframes over which corrective action is required to achieve balance in injections and withdrawals. Nevertheless, such corrective action to maintain security does not occur in real-time, as it does with electricity, and so a wider arrange of interventions are possible to achieve balance, which may or may not require the intervention of a system operator, depending on the extent of imbalances.

There may be some imbalances which have no implications for security of supply over a day, but contracted injections are exceeded by withdrawals, and so a market participant must either arrange for additional supply or pay the system operator to procure additional supplies. As gas reconciliation currently occurs over the period of a month in the New Zealand market, participants have significant flexibility to come back into balance. This situation is unlikely to continue into the future.

Where there are imbalances that lead to security of supply concerns, the system operator must be able to coordinate a response to bring the system back into balance. In the next section we discuss the distinctions between gas and electricity.

5.5.2. Quality of Supply

There are two principal dimensions to quality of supply in electricity. The first relates to the frequency characteristics on the AC network. Frequency must be maintained within certain limits in order to prevent damage to equipment connected to the grid and must be managed in real time. In the event of a fluctuation in frequency, caused for example, by a generator tripping off, reserve generation must be brought on swiftly or customer loads curtailed to ensure that the entire grid is not affected. In the case of electricity, this frequency maintenance process must occur in real-time and be coordinated so that the limits of the transmission system are observed. The advantage of the centralised spot market is that it allows for integrated optimisation of energy and reserves given the time-varying nature of generator costs and availability.

There is no truly analogous concept to "frequency" in the gas market. Because of storage in line-pack, it is possible to balance supply and demand over comparatively more lengthy periods. However, in the event of a major outage, or significant excess demand, the system pressure declines. If this reaches a critical level and water or air enter the system then it is costly and time consuming to repressurise the system, as each customer must be physically closed off from the system to ensure that it can safely be repressurised. So pressure can become a common quality issue in extreme situations. Outages in the gas transmission system tend to be more dramatic in effect (for example, puncturing the transmission line near Himatangi, threatening southward supplies to Wellington) and require a significant response, but are generally less frequent because the system must be designed to prevent potentially explosive gas leaks.

Because it is extremely costly to physically close off all small customers to repressurise the system, every effort is made to prevent complete depressurisation. In general, this involves shutting off the largest customers first, since this can be done quickly and has a material impact on the rate of system depressurisation. So, for example, under the National Gas Outage Contingency Plan, interruption of Maui gas is managed in two stages. The first stage requires "Major Plant", as defined in the Plan, to reduce gas consumption. If supply cannot be restored in time, the second stage requires a reduction in gas consumption by the reticulated gas market. Retailers classify their customers by a load shedding category. The category considers the criticality of the loads and the ability for the loads to be shed and reinstated.

Of course, it would also be possible to use a spot market to achieve a similar outcome, e.g. prices going to extremely high levels to deter use, but it is not clear that this would necessarily be a more efficient means of achieving demand response in a thin market with few customers. The pattern of users curtailing demand would likely be very similar since there are generally few large users capable of making a material difference to system demand. Furthermore, given that time of use meters would be required to monitor curtailment, this may limit the types of customers able to respond to price rationing.

There may be intermediate situations where only limited curtailment may be necessary to maintain security of supply, for example, a small field outage. In such a situation, price rationing may be the most efficient means of allocating scarce supplies. However, given the thinness of the market, potentially low risks of security problems occurring, limited redundancy in the pipeline systems, and low level of storage, the ongoing costs of a spot market would need to be evaluated relative to other means of rationing gas during an outage.

In summary, because there is generally more time to coordinate a response to a gas outage, but also limited choices to manage an outage, the benefits of a centralised spot market to coordinate the response quickly and flexibly is unclear relative to the costs. This contrasts with electricity where a response must be centrally coordinated immediately in response to an outage and there is a diversity of demand and supply-side options.

5.5.3. Demand-Side Distinctions

The nature of demand for the product differs significantly between gas and electricity. From a demand-side perspective, the demand for electricity is highly inelastic, and for the majority of domestic, commercial and industrial customers there are few, if any, economic alternatives.[39] In contrast, for a large majority of gas customers, there are competing alternatives. For example, before committing to a power station investment, a generator will seek a long-term fuel contract and associated transport agreement to cover the risks of contractual opportunism. Willingness to pay for delivered gas will therefore be constrained by competing technologies such as coal, hydro, geothermal, wind etc. Moreover, there are choices about the location of generation investment: either locate close to the gas field and transmit electricity; or close to a load and take delivered gas.

The majority of gas in industrial and commercial uses is for heat and steam raising applications where there are competing fuels such as coal, fuel oil, and biomass (e.g. wood, waste products). Widespread use of alternative fuels in otherwise similar applications suggests that for many customers inter-fuel substitutes are a viable alternative to gas (and may become increasingly competitive as contracts expire that were underpinned by low cost Maui gas).

For residential users, only 220,000 households are connected to reticulated gas, with only approximately 26 to 30 percent of households that front gas mains actually connected in Auckland, and approximately 55 percent in Palmerston North and 60 percent in Wellington.[40] Household users are able to substitute to electricity, solid fuel heating (e.g. log burners) and LPG, so there appear to be viable substitutes to gas. Given also the low penetration of gas in the residential market, the challenge for gas pipeline businesses is to increase the penetration, which will tend to put pressure on pipeline businesses to price the distribution component in a way that encourages gas uptake, thereby diversifying risks across a broader customer base.

The wider availability of demand-side substitutes for gas and immaturity of the New Zealand gas industry has implications for price regulation in the sector. First, the availability of inter-fuel substitutes is likely to materially constrain gas pipeline owners' ability to raise prices. For example, we are advised that the number of special transmission service agreements negotiated by NGC with customers has increased steadily over the last four years. There is likely to be additional pressure in future to negotiate such deals given an expected increase in gas prices as Maui runs down.

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39 In fact, it could be stated that there are none, as all firms must use electricity for some inputs, even if just lighting, etc.

40 Sources: Vector Ltd, "Submission on Commerce Commission's Draft Framework Paper of 16 July 2003," 20 August 2003, pp. 3, 18. Natural Gas Corporation, "Submission In Respect of Draft Framework Paper," 20 August 2003, p. 28.

Secondly, given that gas does not provide essential services, there is no obligation on pipeline providers to invest. Hence, the potential for regulatory error may manifest as a reduction in investment, particularly at the network level where investment to connect new customers may be threatened if investors consider that there is too much regulatory uncertainty, on top of already significant demand uncertainty.

As has been observed in Australia, price and access regulation potentially dulls incentives to invest, or leads to inefficient investment patterns in order to minimise the risks to pipeline providers.[41] For example, pipeline providers may size pipelines to meet the demands of cornerstone customers in order to avoid regulation or the risk that regulators may make an immediate optimisation adjustment because the asset is not initially fully utilised. [

In contrast to regulation of electricity lines businesses, where there may be an implied obligation on electricity businesses to connect new customers, such that under-investment is of relatively less concern, the potential for under-provision of gas pipelines is manifestly greater. Welfare losses from under-investment in pipeline assets would likely dwarf any potential losses from prices exceeding costs.

41 See Productivity Commission (2003) *Review of the Gas Access Regime* Productivity Commission Draft Report p109. A number of submitters had observed that gas pipelines had been undersized to avoid regulation, or minimise the risks that assets would be removed from the regulatory asset base because they may be considered “inefficiently” large.

APPENDIX A: GAS GOVERNANCE OVERSEAS

A.1 INTRODUCTION

This Appendix reviews governance issues in gas markets in the UK, US and Australia.

Given the size and variability of these markets, only the following topics are compared.

1. Tariff control – how are gas commodity and gas transport prices regulated or controlled?
2. Capacity rights – are there physical rights to the network or not?
3. Network control/balancing – how is the pipeline system balanced and flow controlled?
4. Investment control – how are new investment decisions (in gas fields and gas pipelines) made and/or regulated?

A.2 AUSTRALIA

The Australian gas market can be divided into two – the Victorian market and the rest of Australia. While in the rest of Australia the markets are essentially state-based markets, many of the governance and market mechanisms are very similar and hence there is no value for present purposes in separating out these other state markets.

While the focus of the discussion below is on governance of wholesale markets and transport, it is interesting to briefly note developments in retail competition in Australia, particularly regarding governance models. In each of Victoria, New South Wales, South Australia and Western Australia, there is effectively a retail market operator. In Victoria, this role is carried out by VENCorp, which is owned by the Victorian Government. In New South Wales, the retail market operator is the Gas Market Company (GMC), and in South Australia and Western Australia it is the Retail Market Energy Company (REMCo). Both GMC and REMCo are industry-owned firms, but with close relationships with the respective State governments. For example, REMCo has an agreement with the Western Australian Government to ensure that the Government is provided with the necessary information to monitor the implementation of market arrangements and business systems to facilitate competition in the gas retail market.

A.2.1 Australia Apart from Victoria

Gas markets in states other than Victoria operate on a contract carriage model, governed by the National Gas Access Code[42] (although this is now under review as part of the Federal and State government review of energy markets).

Under the Code, a pipeline can be "covered" (i.e. covered by the Code) or not covered (in which case it operates outside the Code). All pipelines existing at the time the Code was enacted are covered, but some new pipelines are not covered.

In the main, shippers using these pipelines have long-term contracts with the pipeline owner, at rates that were negotiated when the pipeline was built or last expanded. Only as these contracts expire do the access arrangements in the Code actually come into effect, as the Code is not allowed to supersede any previous commercial agreement.

The access arrangements for contract carriage pipelines must outline how new participants may gain access to the pipeline (Queuing), arrangements for expanding the pipeline (Extension/Expansion Policies) and a requirement for capacity trading (Trading Policies). They also usually include provisions for the use of capacity not being otherwise used (Interruptible Haulage). These arrangements are defined by the pipeline owner and then subject to ACCC approval through a process of consultation. Therefore, while each pipeline owner may come up with its own, unique, expansion policies (for example) these are then usually modified through the ACCC approval/consultation process.

Also, while the access arrangements make provisions for capacity upgrades to allow new participants to haul gas, they do not oblige pipeline owners to undertake such upgrades. Nor can participants necessarily gain access to pipelines whose capacity is deemed to be fully contracted by other parties, although parties who have contracted capacity that they are not using can be obliged to let others use the capacity on an interruptible basis (but cannot be deprived of their contractual rights).

Relationship with the Commodity (Gas) Sourcing

Typically, gas users contract for gas from a gas producer and contract separately for haulage with a pipeline company. Typically, both are long-term contracts with defined quantities of gas.

The exception is some gas delivered into Queensland where gas and pipeline costs are linked by a complex historical relationship (essentially the gas price is calculated as a net-back).

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42 Victoria is also governed by the NGAC, but a special section was written just for Victoria, which does not apply generally.

New Pipeline Investment

There is no central body overseeing pipeline investment in Australia. New pipelines are built by companies who see a gas demand and a gas supply that could profitably be connected. Having identified the need for the pipeline, the owner will then sign up foundation shippers who will contract for the capacity to be built. Typically, the pipeline is then built to the size required by the foundation shippers and may be expanded by compression and looping after construction.

Three new pipelines have been constructed in Australia in recent years. These are the Eastern Gas Pipeline (build by Duke to link Longford and Sydney); the South East Australia gas pipeline (SEAgas – built by Origin and National Power to link Iona with Adelaide); and the Tasmanian gas pipeline (Duke, under construction, to link Longford with Tasmania).

As the shippers voluntarily entered into these agreements, the pipelines are not "covered"[43] and there is no regulation of the prices paid or any other aspect of the operation of the pipeline, including release of capacity, trading of capacity, interruptible capacity or expansion.

SEAgas entered commercial operation fully contracted, while the EGP was essentially used by Duke to market gas in the Sydney market. Duke's strategy was to operate differently in Australia from the other Australian pipeline companies – by having spare capacity on their pipelines, operating as a shipper themselves and "making a market" in gas at the Longford hub. The Duke pipelines are unique and Duke has now indicated it is exiting the Australian market – it is possible that this will result in more traditional operations in their pipelines once this occurs.

A.2.2 Victoria

Victoria operates a market carriage system of gas market. This is essentially a common carriage system with key features including:

- No capacity being reserved for specific parties; and
- Charges being based on actual use of the system.

This form of access differs from contract carriage (that is, haulage based on transmission contracts as in the US) in that participants require no specific contracts with the pipeline owner in order to haul their gas. In theory, any participant can connect to the system and haul gas, paying the transmission charges and any market costs.

43 In Australian terminology, a pipeline is said to be "covered" if it falls under the jurisdiction of the National Gas Access Code.

The Victoria system also includes a central system operator and a mandatory gas market.

The "mandatory gas market" can be thought of as an explicitly defined way to price and settle imbalances. No firm is exposed to the spot market unless its physical operations diverge from its contracts, i.e., unless its customers withdraw more or less gas than its contract suppliers inject.

The pipeline company earns its revenue for its pipeline from transmission use of system charges. These charges are set by regulation (as they are for contract carriage haulage access charges in the rest of Australia) but the pipeline company has no take or pay contracts to ensure they earn their entire revenue. However, if a company earns less than expected due to lower than expected demand, this may be recovered in the next regulatory reset (depending on the jurisdiction) – much as the access arrangements for contract carriage may allow, or limit, this opportunity in other regions.

The physical aspects of the gas market (nominations, linepack and so on) are managed by VENCorp in Victoria with procedures defined by the Market and Systems Operations Rules (MSOR), which form part of the Victorian Access Arrangements. These rules also detail participation in the market (prudential requirements and so on), nominations and bidding processes, scheduling of gas, settling of the wholesale spot market for gas, metering, management of system security, dispute resolution and future rule change processes.

The Victorian MSOR establishes a market that aims to price imbalances at close to economic value (given the simplifications in the original design of the market) and, as a useful by-product, provides a spot market that even small, undiversified competitors can use to manage their imbalances.

Unlike contract carriage, where physical rights to pipeline capacity are defined, there are no such rights in the Victorian market. This makes access "non-firm" – meaning that no participant has a right, either physical or financial, to move their gas around the pipeline and so risks being unable to deliver gas to their customers.

This aspect of the market has resulted in significant criticism from participants used to operating in "traditional" (i.e. US) gas markets where such rights are paramount.[44]

However, the Victorian arrangements include the concept of AMDQ (Authorised Maximum Daily Quantity). Each retailer and other customers have certain defined AMDQ and in the event of gas shortages or transmission constraints, usage above AMDQ is curtailed first. This ensures that authorised users get priority on the pipeline, much like the contract carriage obligations.

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44 See, for example, the ExxonMobil submission to the COAG Energy Market Review, dated 18 April 2002. ExxonMobil advocated the use of a contract carriage system instead, as per the other states in Australia.

Upgrading the Transmission System in Victoria

There are three ways the gas transmission system in Victoria can be augmented:

- The retailers and customers who require additional capacity can contract directly with providers of transmission capacity. In this case, the additional capacity is paid for by the retailers/customers and the additional capacity is allocated to these parties by way of an additional allocation of AMDQ;
- The owner of the pipelines (GasNet) may decide that augmentation is required and may augment the pipelines itself. In this case, it can include the cost of such capital works into its budget and obtain an increased income under the revenue cap, if the augmentation is approved by the ACCC. If the ACCC does not approve the augmentation it may not be included in the asset base; and
- Pipeline owners can speculatively build pipeline assets without either customers or a certainty of regulated income and hope that the market will reward this speculation.

The augmentation process requires significant information about the pipeline system and the future supply and demand on the system. This is assisted by VENCorp, who produce an Annual Planning Review each year that details demand forecasts, supply options and augmentation requirements. In this way VENCorp can facilitate augmentation by private interests and may encourage particular options, but does not decide on the augmentations that should take place.

The incentive for augmentation is that, while parties can connect to the system without augmenting it, if they do so and a pipeline is congested, then without having AMDQ they have no certainty of firm gas supply. Therefore it is the market in AMDQ that, to a large extent, drives private augmentation.

A.2.3 Summary of Australian Governance

	Victoria	Rest of Australia
Tariff control	Pipeline revenues are regulated with a cap on total revenues that can be earned by the pipeline companies. Retail gas supply tariffs are regulated for small users, with a competitive market for all gas users. Market operator is the government-owned VENCorp.	Access arrangements indicate the maximum tariffs that should be charged on pipelines, however most pipelines are operating under contracts that pre-date the access arrangements. New pipelines can be either regulated or tariffs set by negotiation. Retail market operators are industry-owned firms with Government relationships.

	Victoria	Rest of Australia
Capacity rights	No capacity rights are allocated, access is via "market carriage" and is open to all. However, a system of AMDQ gives a ranking of who will be cut off if supplies or capacity run short.	All pipelines are contracted with capacity rights defined in the contracts. Rights conferred as a result of pre-Code contracts cannot be superseded by the Code, but rights conferred as a result of access arrangements may change if the arrangements change.
Network control/balancing	Managed by a central system operator (Vencorp) in conjunction with a mandatory spot market.	Managed individually by the pipeline owner according to the terms of the contract – so terms vary by pipeline.
Investment control	There is no formal control over investment – market mechanisms encourage private investment if AMDQ is in short supply while GasNet may also augment and obtain regulated returns if the augmentation is approved by the ACCC.	None – investment is purely market driven.

A.3 USA

The US differs substantially from Australia in that it has a vast meshed pipeline network that transports very large volumes of gas from multiple sources. There are over 250,000 miles of transmission pipeline, connecting an equal amount of gathering pipelines. Jointly these systems provide connections between the wells in the producing regions and the consuming markets. There are over 300 local gas distribution companies, hundreds of power plants and thousands of industrial customers tied into this network

This has lead to the development of spot markets at various hubs where pipelines meet – to date there are over 50 hubs in the US, with the Henry Hub being the first and largest. Price formation is the result of interactions across the network between buyers, sellers, and transportation activities. Prices throughout the system tend to be related by transportation costs as well as local supply and demand conditions.

There are a number of regional markets within the US and Canada, these are differentiated by transport constraints, local demand patterns, local supply and so on.

Nevertheless, the general operating rules are essentially the same in all markets. Local conditions may dictate how buyers and sellers may behave in these markets but there is no formal "market" in any of these regions.

The pipelines serving the markets also have slightly different rules and prices. Issues related to flow and balancing are pipeline-specific rather than market-specific.

The gas market in the US can be thought of as two parallel, interrelated markets: one for gas and one for pipeline capacity and ancillary services. This is similar to the market in Australia (excluding Victoria).

A.3.1 Gas Commodity Market

Gas is sold in an unregulated market under essentially bilateral sales agreements – that is, contracts between gas producers and gas retailers.

Prices are reasonably transparent due to:

- The natural gas futures market operated by the New York Mercantile Exchange (NYMEX) at Henry Hub in Louisiana, the heart of the largest and most prolific producing region; and
- The voluntary reporting of sales and quantities at various hubs.

NYMEX

NYMEX prices are quoted on the exchange for standard contract packages of gas (10,000 MMBtu[45]) delivered to Henry Hub on specific dates. The NYMEX allows for price discovery.

Voluntary Reporting/Indices

Physical trades are bilateral and occur at various market hubs around the US and also at various metering points along the transmission pipelines (say at the outlet of a processing plant, or where a gathering pipeline connects to a transmission pipeline). Reporting of these trades comes from:

- Marketers' trading desks; or
- Various industry pricing services that maintain contacts throughout the industry and publish locational prices on a daily, and sometimes hourly basis.

45 2 1 MMBTU equals 1.055 GJ.

The prime gas buying cycle is monthly. Many reporting services provide a first-of-the-month price quote, and then succeeding quotes daily thereafter. Gas is also bought and sold daily, for next day deliveries. There is some intra-day trading as well.

Gas is sold in terms of daily delivery quantity, quoted as Maximum Daily Quantity (MDQ) for a period of time – days, months, and years. Prices are negotiated, but most frequently are tied to publicly quoted daily or monthly gas prices at the most proximate and relevant trading hub (indices). Some price deals may be tied to a market basket of quoted gas prices, or other fuels.

This tends to mean that the gas price is not certain in the contract – unlike in, for example, Australian and New Zealand contracts where the gas price is quoted in $/GJ and changes annually only by the rate of some measure of inflation.

There is considerable gas price volatility, both at Henry Hub and at the other hubs on a day to day basis (there is little evidence of intra-day volatility).

Volatility is driven by:

- Fluctuating demand;
- Pipeline constraints; and
- Supply/demand balance (i.e. scarcity or surplus).

Locational prices across the continental network at the various hubs reflect these local conditions, with few of the locational pricing points have the liquidity of Henry Hub.

More recently there has been evidence claimed of manipulation of prices at hubs with low liquidity – including allegations of marketers lying about prices used to set the indices.

Prices throughout the continental network also tend to be related to Henry Hub by the costs of transportation (net-back pricing) although these relationships change over time as the pipeline network adapts.

A.3.2 Market for Pipeline Capacity

The US system is comprised of contract carriage with secondary trading of the contracted capacity. The rights of shippers to trade capacity contracts is enforced by regulation. Secondary trading of pipeline capacity appears to be very liquid, giving rise to an efficient market in haulage.

However, it should be noted that the US pipelines are often so large that they typically only need to balance over a number of days to stay secure.

This capacity and gas trading has also spawned a rich financial market in derivatives around the industry which is the most developed in the world.

Interstate pipelines are regulated by the Federal Energy Regulatory Commission (FERC) and operate solely as transporters of gas. Historically they were merchants of gas as well, but FERC outlawed this function in 1992. All pipelines are open-access transporters of gas. Most pipelines also operate storage services, and other ancillary services.

Capacity can be purchased on a firm basis or an interruptible basis. Firm shippers on pipelines sign long term firm transportation (FT) service agreements (typically 10 to 20 years). Holders of firm capacity may resell their capacity in a secondary market referred to as the capacity release market.

FT contracts are used to fund network investment, as IT (interruptible transportation) contracts alone do not provide sufficient incentive for investors.

Local distribution companies hold most of the capacity on the interstate network. A service agreement will specify receipt points and delivery points. The holder of a FT contract has firm rights to the capacity in between those points. Firm shippers pay the pipeline under the FERC-approved tariff a transportation rate (this is a regulated cost-based rate) that consists of the following components:

- A reservation charge for the capacity;
- A fixed payment assessed monthly over the term of the contract for the capacity reserved (MDQ per month);
- A commodity rate that recovers variable operating and maintenance costs for each MMBtu of gas actually shipped; and
- A fuel percentage, being gas taken in kind from the shippers' shipments to operate the compressors (shrinkage).

Typically pipelines are sized to meet the sum of the full requirements of their firm shippers.

However, due to fluctuations in demand and throughput, pipelines often have spare capacity that they offer to other shippers on an interruptible basis (IT contracts). Some underutilized pipes may have large amounts of spare capacity. Interruptible rates are quoted in the tariff as the fully allocated form of the firm tariff – that is all fixed reservation charges are rolled into a single per unit interruptible transportation rate. The IT rate is a fully variable.

The difference between the IT and FT service agreements is that the former does not commit the shipper to make reservation payments – he only pays for what he uses, but at a higher variable rate than FT shippers.

Discounting

Pipelines may discount both FT and IT rates but they may not charge more than the FERC tariff.

FERC sets tariffs on the basis of costs, although it occasionally approves market-based rates (rarely, where pipelines can show that they are in competitive markets and cannot exercise market power in setting their prices).

Capacity Release

Shippers who do not need all of their pipeline capacity may release the capacity, that is, offer it for resale/trade to other users. Under FERC rules, the resale in general must be at a rate no greater than the fully allocated tariff rate (i.e. the IT rate) but can be discounted. The exception is for releases of less than 30 days, when shippers may charge more than the fully allocated rate.

Releases occur in two ways:

- Posting the release on the pipeline's bulletin board, so that interested parties may take up the release and negotiate a payment; and

- Bilateral negotiation.

Where releases are made at a discount or have special terms, these terms must be posted on the pipeline bulletin board in case someone else is willing to offer a higher amount.

There is a liquid resale market throughout the U.S. Released capacity competes with IT capacity but is favoured due to the firm nature of release capacity.

Both released and IT prices tend to be at steep discounts to FT during off peak periods.

The firm and IT capacity services offer a flexible and efficient way for US market to manage its capacity. It allows pipelines to sell guaranteed rights to shippers under long term contracts that underpin the financing of the pipeline, while new entry and competition is maximized through the use of interruptible supplies and released pipeline capacity.

In the US, there are areas with capacity constraints. The constrained market drives the need for a flexible system with low-cost options of acquiring capacity as well as low-cost options for capacity expansion. The firm/IT capacity arrangement specifically addresses such a need in managing capacity.

These contrasts with the Australian market where there is essentially no interruptible capacity sold (notwithstanding the requirement for it under the Access Arrangements) and there is little or no market for trading in firm capacity. The differences are driven by both market conditions and governance arrangements. The market is much smaller with many fewer participants than in the US. This tends to reduce the liquidity of the market. Also, until the existing contracts expire, there is no mechanism that can force either the introduction of interruptible contracts on existing pipelines (because the "owners" of the capacity rights can essentially block interruptible supply) nor force these players to trade capacity even when they are not using it.[46]

A.3.3 Balancing

The US pipeline operators manage their intra-day linepack directly by buying/selling gas themselves and/or managing their own storage. The cost of such actions is factored into their tariff structure.

Other pipeline ancillary services include storage, peaking (based on liquefied natural gas – LNG, storage or line pack), "no-notice" service – a form of emergency or peaking service, parking, balancing, and transfer services. These tend to be related to balancing issues.

Shippers are responsible for ensuring their flow is in balance – many pipelines that do not have constraints offer generous balancing terms (up to a month). Constrained pipelines may have shorter timeframes and onerous incentive/penalty regimes for out-of-balance operators.

Pipeline rules determine the imbalance penalties. Contracts between sellers and buyers will stipulate who is responsible for the imbalance penalties, which usually flow to who caused the imbalance in the first place. Imbalance penalties are spelled out in the tariff and typically are set to reimburse the pipeline for the use of its line pack gas. Some pipelines have instituted balancing services (parking and loaning). The balancing period varies from monthly to daily.

Some contracts also specify nomination divergence charge (when nomination differs from actual usage) that can be on an hourly basis.

Network Investment Incentives

Under rate base regulation, incentives are fairly strong to expand the network as this expands the rate base and increases the revenues of the pipeline company. However, the investment has to be proved to the regulator as prudent and it is possible for imprudent investments to be removed from the rate base.

46 We offer no view here on the appropriateness from an efficiency perspective of these policies.

The risk of the investment is also with the pipeline if it cannot sell the capacity. Nevertheless, some areas are under piped, which allows pipelines to receive full rates. If rates remain too high, new pipelines can enter the market.

The US market generally provides sufficient incentive for network investment and a review of the history of the market indicates significant pipeline and storage expansion from both regulated and market companies. Factors contributing to the success are property rights, locational prices in the market and transportation services that are defined from location to location. There are several places where the locational price signals are very strong which clearly justify either pipeline or storage expansion.

A.3.4 Summary of US Governance

	USA
Tariff control	Network tariffs for interstate pipelines are regulated by FERC but can be discounted. Distribution pipelines are generally locally regulated, as are retail tariffs.
Capacity rights	Capacity is sold on a long-term firm basis. Where there is room, interruptible capacity is also sold, and the long-term firm contract capacity is also released and traded. There is a liquid market in pipeline capacity.
Transmission control/balancing	Individual pipelines control their own balancing on individual terms. The balancing period is linked to the need to balance – up to a month is possible but where the pipeline is constrained daily balancing is common. Control is managed by a mixture of tariff penalties and incentives, with the pipeline owner also purchasing gas for linepack and often offering balancing (park and loan) services.
Investment control	Pipeline companies can add prudent new pipelines to their rate base and earn regulated rates on the investment, provided they can sell the capacity (which means that if there is no demand for the pipeline, it does not make commercial sense). New pipelines generally sign up very long term capacity contracts, which underpin their financing.

A.4 UK

The arrangements in the UK are governed by the gas regulator (OFGEM), which also regulates the electricity industry.

OFGEM is responsible for the 5 yearly price reviews as well as the ongoing reforms of the trading arrangements in the two markets.

OFGEM can also monitor market power and anti-competitive behaviour. If found this is referred to the Competition Commission for investigation. However, often the companies involved will agree to voluntary arrangements in order to avoid a Commission referral.

The market is separate for gas commodity and gas transportation services. The purchase of the gas commodity is essentially unregulated and occurs on a bilateral basis between shippers/retailers and a large number of gas producers.

A.4.1 History

The UK gas market has undergone a number of reforms since 1986, when British Gas was privatised. In the first reform, at the time of privatisation, the vertically integrated monopoly was not disaggregated and it was felt that this stifled the development of competition in the market. At this time, British Gas was involved in production (but also purchased large quantities from other suppliers) and was the sole transmission company in the UK and also the sole retailer.

Subsequently, the gas (production and retailing) company was split from the transmission company.

Wholesale gas spot markets developed, as in the US, around the hubs in the UK system – in particular around Bacton where much of the gas from the North Sea enters the UK system. Six other hubs also developed. The gas spot trading was on a bilateral or brokered basis.

Gas transportation was via contracts with the British Gas transmission subsidiary (National Grid Transco), however, since the network was (and still is) operated as a grid rather than a point to point system this was not contract carriage as seen in the US but rather common carriage.

When TransCo was spun out from British Gas in 1997, it introduced a new location for spot trading called the National Balancing Point (NBP), a notional point in the pipeline network at which TransCo balances the system. All gas supplies moving through the high-pressure grid can be traded at the NBP. This central node was more popular than the entry hubs and trade increased dramatically. In 1997, the International Petroleum Exchange (IPE) introduced gas futures contracts based on delivery at the NBP.

Although shippers were required to balance their inputs and off-takes from the system, this did not always occur. In 1996, the Flexibility Mechanism was introduced to allow a market-based determination of the value of the gas required to be injected to restore the system to balance. British Gas traded this gas at an auction with the prices being set by the marginal bid. This system is reasonably similar to the Victorian system.

A key criticism of the market at this time was that it was completely managed by National Grid Transco. This was considered to be a problem in the UK (where there was a trend at the time for bilateral markets to develop, as with the NETA trading system in electricity).

Trading arrangements changed in October 1999. Now trading is undertaken using the New Gas Trading Arrangements (NGTA) which are the gas equivalent of NETA – the New Electricity Trading Arrangements which replaced the UK Electricity Pool in 2001.

A.4.2 New Gas Trading Arrangements

NGTA involves:

- Regulatory, contractual and commercial obligations and incentives on shippers to provide National Grid Transco with accurate nomination information ahead of, and on, the gas day about their intended inputs and off-takes to the network;
- Commercial incentives, set out in the network code, on shippers to balance their inputs and off-takes each day;
- An anonymous, 24 hour, screen based within day gas market, the "On-the-Day Commodity Market (OCM)", that allows shippers to trade out of their imbalances on the day with each other and allows National Grid Transco to undertake residual balancing of the system;
- Scheduling charges on shippers for differences between their final nomination and actual flow at input and Offtake points;
- Contractual obligation on some large Offtake points (such as thermal power stations) set out in Network Exit Agreements that limit the extent to which shippers can increase or decrease their off-takes within specified time limits, to match the physical requirements of the system; and
- Commercial incentives on National Grid Transco to carry out its role as a gas balancing manager in an efficient manner.

Essentially, instead of facilitating a market (as British Gas did with the Flexibility Mechanism and like Vencorp does in Victoria), the new rules penalise players for being out of balance and therefore force them to enter into bilateral trades on the OCM to prevent this from occurring (more like the US).

There are still a number of problems with the UK gas arrangements that are the subject of ongoing debate. Discussions about moving to a shorter time period (i.e. less than a day), trading in linepack and the interrelationship between the gas market and the electricity market continue.

A.4.3 Network Tariffs

National Grid Transco's pricing for transportation services is recovered through CPI-X incentive regulation.

Every 5 years, BGT submits to the regulator (OFGEM) its projection of future costs, including capital requirements, operations and maintenance costs, return on equity and other costs that comprise the utility's cost base.

OFGEM then determines the allowed tariffs for different customer classes that will enable BGT to collect it revenue requirement. These rates include a component that escalates with inflation (the retail price index, or RPI). This is similar to traditional cost-of-service regulation. OFGEM also decides on an appropriate productivity factor (X), which is then included in the analysis. X can be positive or negative. Where X is positive, it limits the extent to which BGT may increase annual average tariffs to some percentage less than RPI. However, in some instances X may be negative, in which case the formula turns into a "RPI+X" formula and allows the company to recover more than RPI each year.

The final result is an initial tariff and a formula that operates for the next five years on an RPI-X basis.

If National Grid Transco can lower its costs or improve efficiency more than projected in its rate filing to OFGEM, it can retain the difference for the regulatory period.

Since April 2002 there have been separate price controls for the National Transmission System (NTS) and the Local Distribution Zones (LDZs). The NTS control is further subdivided into Asset Owner (TO) and System Operator (SO) controls. Transportation charges are now set to reflect these price control arrangements.

System Entry Capacity

For each of the system entry points capacity is made available on a firm and interruptible basis. All entry capacity is offered on a pence per kWh per day basis where the quantity is measured in terms of an end of day entitlement. Interruptible capacity is limited to being offered on a daily basis in an auction that is conducted on the day ahead of the intended day of use.

Firm Entry Capacity is offered in bundles of quarters, months and days.

Transco offers two daily capacity services – a firm Daily System Entry Capacity service (DSEC) and a Daily Interruptible System Entry Capacity service (DISEC). Both services are offered through a tender process and are subject to minimum reserve prices:

- DSEC availability is presently defined in the Network Code as the amount, determined by Transco, by which system entry capacity exceeds firm system entry capacity held by shippers; and

- DISEC is allocated by means of a single tender that is held on the day before the gas day. DISEC consists of any unutilised booked monthly capacity on a day.

Distribution Charges

Within the LDZ price control revenue recovery is split between use-of-system charges and customer charges. The relative level of these charges is based on the relative level of costs allocated to these areas of activity by Transco's Transaction Model.

A.4.4 Balancing and Control

The system is operated as a single grid by National Grid Transco. There are regulatory, contractual and commercial obligations and incentives on shippers to provide National Grid Transco with accurate nomination information ahead of, and on, the gas day.

The Incentivised Nomination Scheme (INS) provides shippers incentives to give National Grid Transco an accurate forecast of their intended end-of-day imbalance position. These incentives encourage shippers to balance their inputs and offtakes each day, and include scheduling charges on shippers for differences between their final nominations and actual flows.

There are also contractual obligations on shippers to use reasonable efforts to flow gas with a uniform flow rate. Currently, National Grid Transco is considering a monitoring system to encourage shippers to provide timely and accurate withdrawal information

National Grid Transco can also use terminal flow advices (TFAs) to request a delivery facility operator (DFO) to reduce flows into the network for a specified period of time to prevent over-pressurization. There are also contractual obligations on some large offtake points (such as power stations) in Network Exit Agreements (NexAs) that limit the extent to which shippers can increase or decrease offtakes within specified time periods.

In its residual balancing role, National Grid Transco has to buy or sell gas to keep the system in balance overall. System linepack is used to accommodate imbalances within the day to a certain degree. The costs for residual balancing are recovered from all shippers through a "neutrality charge".

National Grid Transco's gas balancing incentive has a price and linepack component. For the price component, National Grid Transco can receive up to £5,000 a day if it minimizes the spread between its marginal purchase price and marginal sales price. On the other hand, it is exposed to a penalty up to £30,000 a day when the difference is two times the System Average Price (SAP) or more.

The linepack component is to discourage National Grid Transco from carrying over imbalances from day to day. National Grid Transco can receive up to £5,000 per day if there is no difference between the opening and closing linepack. If the difference is greater than 2.4mcm, it starts to lose money. The daily collar loss is £30,000 for a difference of 20.4 mcm or more. There is an annual cap and collar for the price and linepack incentives.

Currently, shippers pay for the flexibility provided by the system linepack in a "bundled product" with transmission services, while National Grid Transco uses system linepack as a balancing tool.

A.4.5 Summary of UK Governance

	UK
Tariff control	Network tariffs are based on entry/exit charges for the transmission grid and use-of-system and customer charges for the distribution grid. Prices are regulated by OFGEM using an RPI-X incentive based regulation.
Capacity rights	Firm Capacity is auctioned at entry terminals to the system on annual, quarterly, monthly and daily basis. Interruptible capacity is auctioned daily.
Network control/balancing	Individual shippers are penalised for being out of balance and must trade with each other and with Transco to balance their flows. Transco manages the grid and has incentives to minimise linepack and buy/sell price variations. Issues such as locational pricing and flow rates by electricity generators are the subject of ongoing proposals for change, including a market in linepack.
Investment control	Transco appears to have obligations with respect to system security that require it to build new pipelines if the need arises. It appears that these are then included in the 5-yearly network tariff reset as capital expenditure which increases the asset base upon which the regulated prices are set.

	UK
	Other pipeline companies also build pipelines – particularly small distribution networks connecting new housing estates and similar. These are also subject to open access provisions but apparently not price control (although this is also subject to ongoing debate).

This market has many of the attributes required for a successful competitive market – multiple suppliers; a common carriage grid and many shippers. It has been reforming and developing for over 15 years. The fact that these significant problems remain highlights the difficulties facing gas reform and the complexities gas markets can involve.