Review of implications for energy markets from climate change policies – Western Australian and Northern Territory elements

A REPORT PREPARED FOR THE AUSTRALIAN ENERGY MARKET COMMISSION

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Tables and figures

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Glossary of terms

Alternative Maximum STEM Price: This is the maximum price that can be offered into the STEM by liquid fuelled facilities. Clause 6.20.7(b) of the Market Rules specifies the methodology the IMO must use in calculating this price.

Bilateral Contracts: Bilateral trades of energy or capacity that occur between Market Participants.

Downward Deviation Price (DDAP): DDAP is the settlement price for deviations below Net Contract Position and is defined as 1.3 x MCAP during peak periods and 1.1 x MCAP during off-peak periods.

Electricity Generation Corporation: The Electricity Generation Corporation is the former generation business division of Western Power Corporation and is registered as a Market Generator. The Electricity Generation Corporation's facilities follow a different scheduling process to other Market Generators, it is required to balance the entire system in real-time (to the extent it is able), and it is required to make its capacity available to System Management to provide ancillary services. The Electricity Generation Corporation currently trades under the name *Verve Energy*.

Electricity Networks Corporation: This is a Network Operator and was formerly the network division of Western Power Corporation prior to disaggregation. The Electricity Networks Corporation currently trades under the name *Western Power (Networks)*. A ring-fenced business unit of the Electricity Networks Corporation performs the role of System Management.

Electricity Retail Corporation: The Electricity Retail Corporation is the former retail business division of Western Power Corporation and is registered as a Market Customer. The Electricity Retail Corporation currently trades under the name *Synergy* and is the only retailer allowed to serve customers that do not have interval meters.

Independent Market Operator (IMO): The IMO is the Market Operator and Market Administrator. It also conducts, *inter alia*, long term (ten year) generation adequacy planning.

Independent Power Producer (IPP): These are Market Generators other than the Electricity Generation Corporation.

Marginal Cost Administrative Price (MCAP): A balancing price that is calculated in the event that real-time effective demand deviates from expected demand.

Market Customer: This is a retailer or any other party that purchases power from the market for the purpose of consumption or retail sale. The Electricity Retail Corporation is the Market Customer that supplies non-contestable retail customers, and is the supplier of last resort to the retail market.

Market Generator: This is a party that operates a generating facility and must be registered if it is to provide energy to the market. Subject to some exemptions in the rules, it is expected that all generating facilities above 10 MW will register. Market Generators are either the Electricity Generation Corporation or Independent Power Producers (IPPs).

Market Participant: This is a Rule Participant that trades in the reserve capacity or energy markets.

Maximum STEM Price: This is the maximum price that can be offered in the STEM by non-liquid fuelled facilities. Clause 6.20.7(b) of the Market Rules specifies the methodology the IMO must use in calculating this price.

Metering Data Agents: Parties that provide meter data to the IMO. The Electricity Networks Corporation is the default Metering Data Agent if another Network Operator does not fill this function.

Minimum STEM Price: This is the minimum price that can be offered or bid in a STEM Submission and is equal to the negative of the Maximum STEM Price.

Net Bilateral Position: A participant's net position in the bilateral contract market, taking into account contracts to supply and contracts to purchase energy.

Net Contract Position: The combined Net Bilateral Position and STEM position of a Market Participant defines its Net Contract Position

Network Operator: This is a party that operates, or intends to operate, a transmission or distribution network within the SWIS, and is required to be registered. Network Operators can also be Metering Data Agents.

Rule Participant: Registration as a Rule Participant requires an entity to comply with the Market Rules. This process is automatic for System Management and the IMO.

Scheduling Day: The Scheduling Day is the day prior to the Trading Day.

Short Term Energy Market (STEM): The STEM is an energy-only forward market operated by the IMO on the Scheduling Day to facilitate trading around bilateral contract positions.

STEM Price: The price at which cumulative supply equals cumulative demand in the STEM.

STEM Submission: A STEM Submission is a submission made by a Market Participant to the IMO containing the (i) a portfolio supply curve, (ii) a portfolio demand curve, (iii) a fuel declaration, (iv) an ancillary service declaration and (v) an availability declaration. The STEM Submission is used by the IMO to determine a Market Participant's STEM Offers and STEM bids.

System Management: System Management is the System Operator. It conducts short and medium term (up to three years) system planning, including outage planning. It schedules Electricity Generation Corporation resources, while respecting Independent Power Producer (IPP) transactions. In real-time it dispatches the power system, and can only change IPP schedules under special circumstances. System Management is a ring-fenced entity within Western Power.

Trading Day: The day of the STEM auctions.

Trading Interval: The STEM's Trading Interval is half-hourly. Two STEM auctions are run each hour – one for each Trading Interval.

Upward Deviation Price (UDAP): UDAP is the settlement price for deviations above Net Contract Position and is defined as 0.5 x MCAP during peak periods and zero during off-peak periods.

Executive summary

INTRODUCTION

This report has been prepared by Frontier Economics (Frontier) for the Australian Energy Market Commission (the Commission) as part of a review and discussion of the implications of the Carbon Pollution Reduction Scheme (CPRS) and the expanded national Renewable Energy Target (RET) scheme for the Western Australian and Northern Territory energy markets.

This report is the second stage of a two-stage review. The first stage comprised of a descriptive review of the Western Australian and Northern Territory energy markets. This Stage I report is contained in Appendix A. The primary purpose of this Stage II report is to identify and discuss the direct and consequential effects of climate change policies on the Western Australian and Northern Territory energy markets.

OUTLINE OF WESTERN AUSTRALIAN AND NORTHERN TERRITORY ENERGY MARKETS

Western Australia's energy markets are dominated by the Wholesale Electricity Market in the South-West Interconnected System, coupled with the presence of vast natural gas reserves in the Carnarvon, Browse and Bonaparte basins. Importantly, increasing quantities of natural gas are being exported as processed LNG from the Carnarvon basin. The ERA regulates Western Australia's electricity and gas industries.

The Northern Territory's energy markets are dominated by the primary Darwin-Katherine regulated electricity system and a large export-LNG facility located onshore near Darwin, which sources gas from the Bonaparte basin. The Utilities Commission regulates the Territory's electricity industry, while regulation of the gas industry falls under the jurisdiction of the Australian Energy Regulator.

GENERIC EFFECTS OF CLIMATE CHANGE POLICIES

Climate change policies

The Government's two primary climate change policies going forward are the CPRS and the expanded national RET scheme. The CPRS aims to reduce Australia's emissions of greenhouse gases in the long run, to 60 percent of 2000 levels, by 2050. In the energy sector, the scheme essentially acts as a tax on emissions to change the relative cost structure of generation, in order to favour cleaner plant.

As the CPRS will take time to encourage renewable generation investment in Australia, the expanded national RET scheme aims to bring forward this investment by offering renewable generation an output subsidy. The expanded national RET scheme aims to ensure that at least 20 percent of Australia's electricity supply is generated from renewable sources by 2020.

Generic effects of the CPRS

The direct effect of the CPRS will be to increase the cost of using emissions-intensive energy sources, such as coal and gas. This direct impact has several consequences for Australia's energy markets:

- The higher relative cost of coal-fired generation under the CPRS will result in higher electricity prices and shifting from coal- to gas-fired generation, other things being equal;
- Fuel shifting from coal- to gas-fired generation will result in increased demand for natural gas. The impact on gas prices will depend on the availability of natural gas and the extent to which prices in domestic markets are set according to international LNG prices;
- The increased demand for natural gas going forward may also place increased pressure on gas transmission and distribution networks, which may need to be augmented over time;
- To the extent that the CPRS results in increased wholesale electricity and gas prices, regulated retail tariffs may need to be reviewed to ensure the viability and financial liquidity of retailers due to increased wholesale prices;
- The impact of the CPRS on the valuation of existing generation assets has potential implications for the financial viability of, and prudential risks faced by, market participants; and
- In the longer term, pricing signals emanating from the CPRS will incentivise investment in zero- and low-emission generation technologies. This is expected to occur only once permit prices begin to ramp up as the scheme matures.

Generic effects of the expanded national RET scheme

The direct effect of the expanded national RET scheme will be to increase the demand for RECs, from retailers. This has several consequences for Australia's energy markets:

- By creating a demand for RECs, the expanded national RET scheme will increase the quantity of renewable generation capacity in Australia in the short to medium term;
- An increase in renewable generation may have a number of negative risks and implications for electricity markets, particularly for the maintenance of power system security. Most of these implications are attributable to the intermittent and unpredictable nature of key renewable sources, such as wind;
- To the extent that renewable generation provides an abatement substitute to fuel shifting, the expanded national RET scheme may mitigate some of the effects on domestic wholesale gas prices driven by the CPRS (even though this mitigation will itself be limited by the need for some gas 'back-up' generation to support the growth of wind given the unpredictability of wind plant output); and

- Due to the interaction between the CPRS and the expanded national RET scheme, rising wholesale electricity spot prices driven by the CPRS will reduce the REC price received by renewable generation over time for a given target level of renewable generation.

JURISDICTION-SPECIFIC EFFECTS OF CLIMATE CHANGE POLICIES

The generic effects of the CPRS and the expanded national RET scheme are only partially relevant to Western Australia and the Northern Territory, due to various local factors in these markets. The primary difference between the Western Australian and the Northern Territory energy markets as compared to the southern and eastern states is the extent to which their local natural gas prices are influenced by international LNG prices. Due to Western Australia's and the Northern Territory's large LNG-export facilities, domestic gas prices in these jurisdictions are considerably higher than gas prices in the NEM jurisdictions.

Impacts specific to Western Australia

The key feature of the Western Australian energy markets that modifies the generic effects of these climate change policies is the magnitude of the relative cost difference or 'spread' between coal- and gas-fired generation, compared to the southern and eastern states. Specifically:

- Due to the large coal-gas cost spread, the extent of fuel shifting from coal- to gas-fired generation in the short to medium term is expected to be far less than in the NEM. Rather, coal-fired generation may be more economic than gas-fired plant in Western Australia in the short to medium term. This is consistent with the observations of new coal-fired plant currently being proposed or constructed. The extent to which these plant will remain economic as permit prices ramp up going forward is uncertain. In the longer term, fuel shifting may begin to occur due to the ramping up of carbon permit prices;
- The issues created by Western Australia's below-cost regulated electricity retail tariffs are likely to be exacerbated by the introduction of the CPRS and the expanded national RET schemes, due to the rising costs of serving load. The new government has not yet announced whether it will act on the Office of Energy's recommendations for substantial tariff increases over the next few years to restore cost-reflectivity;
- The likely substantial increase in wind generation in Western Australia due to the expanded national RET scheme is likely to place increasing strain on the management of system security and reliability in the absence of major changes to the market design. For example, if no changes are made, increasing wind penetration could require conventional plant to be turned down overnight when load is low. This could harm efficiency and reliability if those plant cannot be quickly restarted the next day to meet peak loads. More wind farms are also likely to extend already lengthy delays for new generators to obtain network connections.

Impacts specific to Northern Territory

While some of the effects of the CPRS and the expanded national RET scheme on Western Australia's energy markets also apply directly to the Northern Territory, the size and relative simplicity of the Territory's energy markets negates many of these impacts. Major jurisdictional-specific effects of these schemes on the Northern Territory's energy markets include:

- Due to a lack of fuel diversification and viable renewable generation alternatives, the Northern Territory is unlikely to experience significant shifting between generation technologies;
- Due to climatic factors, the Territory is largely unable to exploit viable renewable generation alternatives (in particular wind and biofuels) to the same degree as other jurisdictions. For this reason, Territory entities will likely need to purchase RECs from other jurisdictions in order to satisfy their expanded national RET obligations going forward; and
- As with Western Australia, to the extent that either the CPRS or the expanded national RET scheme result in increased costs to serve electricity or gas customers, regulated retail tariffs may need to be reviewed to ensure the viability of existing retailers, and to encourage competition in the retailing sector going forward.

CONCLUSIONS

The CPRS and expanded national RET scheme will have certain unique effects on the Western Australian and Northern Territory energy market arrangements. This is largely because of the high gas prices in both jurisdictions as compared to the NEM, due to the scope for LNG exports. For this reason, it is unlikely that fuel shifting from coal to gas will occur to the same degree as in the NEM states.

In the short to medium term, the expanded national RET scheme will incentivise increased investment in renewable generation, particularly in wind plant. Due to the high quality of wind sites in Western Australia and the high cost of gas, it is expected that a move to substantial investment in wind generation will occur in Western Australia before such investment occurs in the eastern states. However, increased quantities of wind generation are creating a number of difficult issues for the Western Australian electricity market relating to system security, network planning, connection and the need for ancillary services. Most of these issues are driven by the intermittent and unpredictable nature of wind generation. These issues are not present in the Northern Territory, due to the lack of viable renewable generation options at the current time.

In both jurisdictions, both the CPRS and expanded national RET scheme are likely to lead to higher retail costs to serve for both electricity and gas. These effects may need to be reflected in regulated retail tariffs to ensure new retail entry is not deterred.

1 Introduction

This report has been prepared by Frontier Economics (Frontier) for the Australian Energy Market Commission (the Commission) as part of a review and discussion of the implications of climate change policies for the Western Australian and Northern Territory energy markets. These climate change policies consist of the Carbon Pollution Reduction Scheme (CPRS) and the expanded national Renewable Energy Target (RET) scheme.

The Commission engaged Frontier for an assignment consisting of two key parts:

- Part I – A summary of the existing market structures and supporting energy market frameworks in Western Australia and the Northern Territory; and
- Part II – Identification and explanation of:
  - the direct and consequential effects of climate change policies on behaviour in the Western Australian and Northern Territory energy markets;
  - the risks of inefficient or unintended outcomes due to the introduction of climate change policies and the direct and consequential changes in behaviour that may result;
  - how the existing arrangements act to mitigate or exacerbate such risks; and
  - the potential sub-optimal outcomes that may occur, and their potential materiality, given the existing arrangements.

Frontier has previously submitted a report to the Commission addressing Part I of the review (the Part I report). This report focuses on Part II of the assignment. Nevertheless, for the sake of completeness and to promote the readability of this report, we have included a brief summary of the material in our Part I report in section 2 of this report. The Part I report is attached in its entirety as Appendix A to this report.

With respect to the remainder of the report, Frontier considers that all elements of Part II relate to the same process of analysis. For example, the likely effects of climate change policies cannot be considered without an understanding of the risks of inefficient outcomes and the potential sub-optimality of the outcomes that may occur. All of these topics are inter-related and need to be considered together. Therefore, this report does not respond separately to each element within Part II.

This report is structured as follows:

- Section 2 provides a brief summary of the key features of the Western Australia and Northern Territory electricity and gas market arrangements, at both wholesale and retail levels. This material is derived from our Part I report to the Commission;
- Section 3 discusses the generic effects of the CPRS and the expanded national RET scheme on electricity and gas markets. This includes a

discussion of the various issues highlighted above that relate to Part II of the assignment;

- Section 4 discusses the jurisdictional-specific effects of the CPRS and expanded national RET scheme on the Western Australian and Northern Territory energy market structures and arrangements. This includes a discussion of the various issues highlighted above that relate to Part II of the assignment; and
- Section 5 concludes.

A complete collection of references used in undertaking this review can be found at the end of this report. As noted above, Appendix A contains Frontier's Part I report. Appendix B contains a numerical STEM example referred to in the Part I report.

2 Outline of Western Australian and Northern Territory energy markets

This section briefly recaps the energy market structures and arrangements operating in Western Australia and the Northern Territory. A more detailed description of these features was provided to the Commission in the Part I report, which can be found in Appendix A.

2.1 WESTERN AUSTRALIA

2.1.1 Electricity

Background

Western Australia's electricity supply industry is comprised of several distinct systems – the South West Interconnected System (the SWIS), the North West Interconnected System (the NWIS), and 29 regional, non-interconnected power systems.[1] Western Australia's primary electricity infrastructure is illustrated in Figure 1. No part of Western Australia's electricity networks interconnect with the National Electricity Market (NEM).

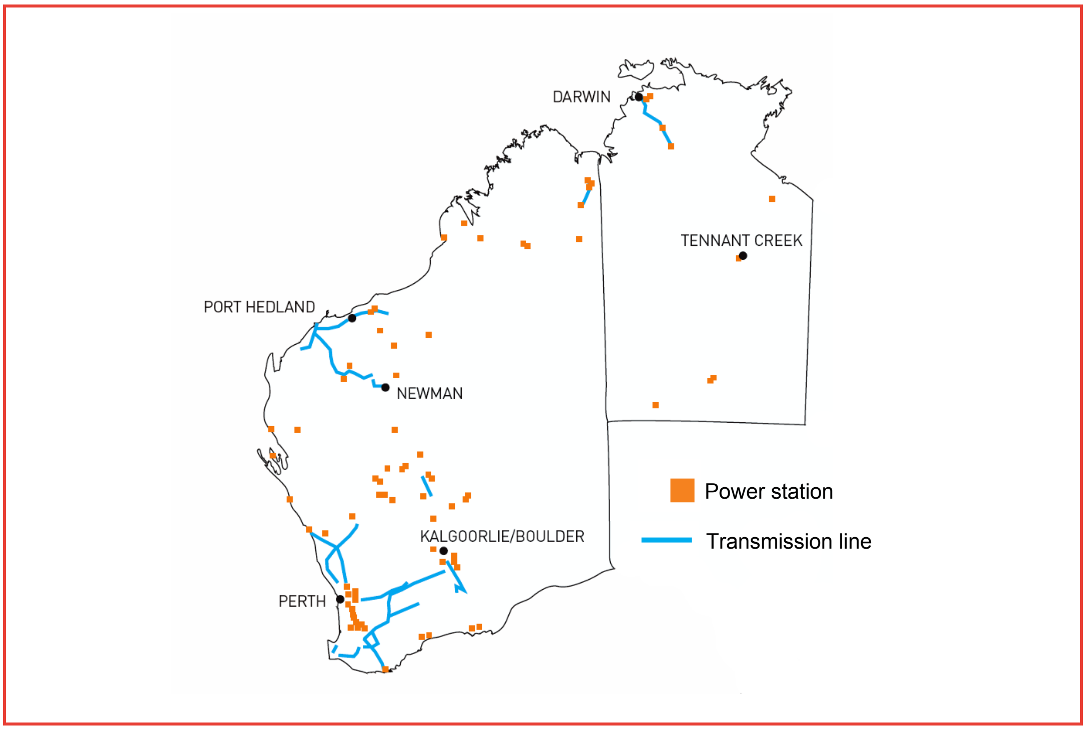

Figure 1: Western Australia and Northern Territory electricity infrastructure

Source: AER (2007), p.64.

[1] AER (2007), p.204.

The SWIS is the major interconnected electricity network in Western Australia, supplying the bulk of the south-west region, comprising 5,135MW of installed capacity as of August 2008. Western Australia introduced the Wholesale Electricity Market (WEM) into the SWIS in September 2006. In 2004/05, approximately 21% of total final electricity consumption in Western Australia was used for residential purposes, with the remaining 79% being used for commercial and industrial purposes.[2]

Institutional and governance arrangements

Several key governance bodies exist in the WEM:

- IMO – the market operator who maintains and develops the Market Rules and procedures, registers Rule Participants and operates the Short Term Energy Market (STEM) and the Reserve Capacity Mechanism;
- System Management – a ring-fenced entity within Western Power responsible for operating the power system to maintain security and reliability;
- Economic Regulatory Authority (ERA) – the jurisdictional regulator, responsible for economic regulation and market monitoring; and
- Market Advisory Committee – an industry and consumer group convened by the IMO to advise on changes to Market Rules and procedures.

Market Structure

As at 30th September 2008 there were a total of 30 participants[3] registered with the IMO. These included:

- 14 entities registered as Market Generators only;
- 8 entities registered as Market Customers only; and
- 8 entities registered as both Market Generators and Market Customers.

However, the SWIS is dominated by three State-owned legislative corporations that resulted from the disaggregation of Western Power:

- Western Power Networks – responsible for operating the transmission and distribution system;
- Synergy – the incumbent retailer with a monopoly over smaller customers; and
- Verve Energy – the largest Market Generator in the SWIS.

The new Premier of Western Australia has recently suggested that the Government is considering the amalgamation of Synergy and Verve Energy, in an attempt to stem the losses arising from the vesting contract arrangements

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2 ABARE (2006).

3 See http://www.imowa.com.au/PUB_RulePartClassInfo.htm. This excludes the Network Operators, the Regulator, the Market Operator and the System Operator.

(discussed below) between these two parties.[4] The current status of this proposal is at this stage unclear.

Wholesale market arrangements

The WEM became fully operational in September 2006. The WEM's Energy Market, as defined and used in the Market Rules, describes all mechanisms for trading energy[5] in the WEM. It includes transactions made via three key mechanisms:

- Bilateral contracting – incorporating contracts entered into years, months or days before the Scheduling Day. This includes the Vesting Contract between Verve Energy and Synergy, which hedges Synergy's non-contestable and inherited customers.[6] For each participant with bilateral contracts, a Net Bilateral Position can be determined;[7]
- STEM – the day-ahead energy-only market operated by the IMO. The STEM is designed to facilitate trading by Market Participants around their Net Bilateral Positions. Participants who wish to participate in the STEM are required to submit to the IMO their entire portfolio demand and supply curves, along with their Net Bilateral Positions – their STEM bids and offers are then derived from this information. A participant's Net Contract Position is the sum of its Net Bilateral Position and its Net STEM Position;[8] and
- Balancing – the real-time process for keeping the SWIS in balance in light of deviations in demand from forecast and deviations in supply from participants' Net Contract Positions. System Management primarily schedules Verve Energy to provide balancing, but may issue instructions to other parties if required. A participant's balancing (instructed) deviations from Net Contract Position are settled at more favourable prices than unauthorized deviations:
  - Balancing deviations are settled at MCAP (Marginal Cost Administrative Price, a STEM-based price) for Verve Energy and pay-as-bid prices for other generators; and
  - Unauthorised deviations by IPPs are settled at prices below MCAP for additional generation (known as Upward Deviation Price or UDAP) and

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4 See http://www.abc.net.au/news/stories/2008/10/09/2386447.htm

5 Bilateral contracting of Capacity Credits and RECs are not considered by the IMO as being part of the WEM's Energy Market.

6 The Vesting Contract is a contract for energy and Capacity Credits between Verve Energy and Synergy. The energy under the contract is priced on the basis of a 'netback' pricing arrangement, according to which Verve Energy is paid the residual of Synergy's sales revenues after accounting for efficient retail, network and other costs. The implication of this is that changes to regulated tariffs will affect the price that Verve Energy ultimately receives for energy under the Vesting Contract. If regulated retail tariffs are set below cost, as at present, it is Verve Energy – not Synergy – that does not recover all of its costs.

7 IMO (2006), p.44-45.

8 IMO (2006), pp.45-51.

prices above MCAP for insufficient generation (known as Downward Deviation Price or DDAP) – i.e. IPPs are required to *pay* for the energy they were scheduled to generate but did not.[9]

The IMO's settlement process will not be zero-sum, since the UDAP and DDAP prices as well as the pay-as-bid obligation create a mismatch between income received and payments made. The IMO tends to recover more revenue than it pays out due in part to deviation charges. Excess market revenue from this process is redistributed to Market Participants each month through a non-STEM reconciliation payment.

In addition, unlike the NEM which is an energy-only market, the WEM has a Reserve Capacity Mechanism administered by the IMO to ensure adequate generation capacity exists to meet expected demand in a given time period. The IMO determines the capacity required in each year so as to:

- Ensure that forecast peak demand after the outage of the largest generation unit in the SWIS can be met, while maintaining some residual frequency management capability (e.g. 30 MW), in nine years out of 10; and
- Limit energy shortfalls to 0.002% of annual energy system consumption.[10]

Annual Reserve Capacity Requirements are specified annually by the IMO based on the capacity requirements of the SWIS for the succeeding 10 years. Each Market Customer is allocated a share of this Reserve Capacity Requirement, called its Individual Reserve Capacity Requirement, and is required to secure Capacity Credits to cover its requirement. Capacity Credits are effectively (i) installed capacity by Market Generators or (ii) Demand Side Management (DSM) by Market Customers that has been registered with the IMO.

To fulfil its Individual Reserve Capacity Requirement, a Market Customer can either procure Capacity Credits bilaterally from Capacity Credit suppliers (generators and DSM facilities), or it can purchase Capacity Credits from the IMO. The IMO may run an annual auction to procure Capacity Credits for on-sale to Market Customers if the requirement for Capacity Credits is not met through bilateral trade.[11] To date, this has not been required. Suppliers of Capacity Credits must be willing and able to make their capacity available to the market in real-time when requested to do so by System Management.

Retail market arrangements

The retail market in Western Australia has been progressively opened to retail competition since 1997. Currently, all customers that consume more than 50 MWh per annum are contestable (about 15,000 customers, or 1.5 per cent of

9 IMO (2006), pp.51-56.

10 IMO (2006), pp.28-29.

11 IMO (2006), pp.28 and 31-33.

total customers).[12] Because these customers are large users of electricity, they may represent up to 60 per cent of total energy consumption.[13]

Contestable customers can be supplied either by the incumbent retailers – Synergy for customers inside the SWIS and Horizon Power for customers outside the SWIS – or new entrant retailers. In its most recent annual report on retailer performance, the ERA noted that there were a total of five retailers operating in the Western Australian market in 2006/07. Customers who consume 50 MWh or less are not considered contestable and are supplied by Synergy (within the SWIS) or Horizon Power (outside the SWIS).

Currently, regulated tariffs exist for all customer groups in Western Australia:

- Non-contestable customers in the SWIS (those consuming 50 MWh per annum or less) must be supplied by Synergy at the regulated tariff;
- Contestable customers in the SWIS that consume between 50 MWh and 160 MWh per annum can choose to negotiate a contract with any retailer at a negotiated tariff, or can opt for supply from Synergy at the regulated tariff; and
- Contestable customers in the SWIS that consume more than 160 MWh per annum can choose to negotiate a contract with any retailer at a negotiated tariff. Regulated tariffs also exist for these customers, but Synergy is not obliged to supply these customers at the regulated tariff.

Similar obligations are imposed on Horizon Power for customers outside the SWIS. The Government has adopted a uniform tariff policy, where some of the tariffs within and outside of the SWIS are the same for the same class of customers. Tariffs within the SWIS are set out in the *Energy Operators (Electricity Retail Corporation) (Charges) By-laws 2006* and tariffs outside the SWIS are set out in the *Energy Operators (Regional Power Corporation) (Charges) By-laws 2006*. In both regions, tariffs are defined for particular classes of customers. For instance, the residential tariff within the SWIS is the A1 tariff and the residential tariff outside the SWIS is the A2 tariff. Due to the uniform tariff policy, the A1 tariff and the A2 tariff are equivalent. Similarly, the low/medium voltage business tariff within the SWIS is the L1 tariff and the low/medium voltage business tariff outside the SWIS is the L2 tariff. Due to the uniform tariff policy these are also equivalent. A full set of tariffs is sets out in the By-laws noted above.

The Minister for Energy is currently reviewing retail tariff arrangements. The Office of Energy's draft recommendations report to the previous Minister for Energy recommended that regulated tariffs should increase in order to reflect increases in the costs of supplying electricity. The Office of Energy recommended that residential tariffs should increase by 47 per cent effective from 2009/10, and tariffs for other small use customers should increase by between 21 per cent and 44 per cent. The former Premier, Alan Carpenter, instead affirmed that there would be a 10 per cent increase in tariffs from

[12] ERA (2008b).

[13] ERA (2009b).

2009/10 with further annual increases to be phased in over a six to eight year period. The new government's position on cost-reflectivity of retail tariffs is as yet unclear.

System Operation

As noted above, system operation functions in the WEM are performed by System Management, a ring-fenced entity located within Western Power. System Management's principal function within the SWIS is the maintenance of power system security and reliability. To achieve this, System Management must operate the power system within a technical envelope that accounts for the operating and ancillary service standards in the Market Rules and technical codes, as well as equipment and security limits provided by network operators and other participants.[14] System Management's role includes:

- Dispatching the market;
- Proposing requirements for, and procuring, ancillary services;
- Undertaking short and medium term reserve and outage planning;
- Managing abnormal operating states; and
- Investigating and reporting on major disturbances.

Network Regulation

The *Electricity Networks Access Code* 2004 (Access Code) prescribes commercial arrangements, including charges, that apply in respect of electricity generators and retailers accessing regulated or 'covered' electricity networks in Western Australia.

Under chapter 5 of the Access Code, Western Power is required to propose an access arrangement that describes the terms and conditions of access to the South West Interconnected Network (SWIN)[15]. Western Power's access arrangement was finally approved by the ERA on 26 April 2007 (the Access Arrangement).[16]

Chapter 6 of the Access Code sets out the objectives and requirements for a price control within an access arrangement. In short, the price control is intended to provide for the service provider (e.g. Western Power) to earn a target level of revenue based on the forward-looking efficient costs of providing covered services, including a reasonable return on investment.[17] The price control mechanism is also intended to provide Western Power with incentives to exceed

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[14] IMO (2006), p.21.

[15] The ERA interprets the SWIN as being the regulated networks within the SWIS that are owned by Western Power. The SWIN is interconnected with two other (private) networks: Southern Cross's Boulder-Kambalda network and International Power Mitsui's transmission line at Kwinana.

[16] See the ERA website at: http://www.era.wa.gov.au/1/264/48/electricity.pm.

[17] Access Code, chapter 6, especially clause 6.4.

efficiency, innovation and service quality benchmarks. The target revenue may also be adjusted for unforeseen events and changes to the Technical Rules.

An overview of Western Power's network planning process is contained in its Access Arrangement Information document.[18] Western Power's approach to network planning is informally referred to as embodying an 'unconstrained' network approach.[19] The precise meaning of this term is not defined in any published documents. However, based on correspondence with Western Power staff, it derives from the requirement in the Technical Rules for Western Power to plan, design and construct its power system to ensure that power system stability and performance can be met under the worst credible load and generation patterns and the most critical credible contingency events, without exceeding any component ratings or the allocated power transfer capacity.[20] This, in turn, has led Western Power to only connect new generators where and when the network can accommodate the full output of connected generator(s).[21]

By contrast, the 'constrained' network approach used in the NEM allows generators to be connected even though the transfer capability of the network may not be sufficient to ensure they are dispatched when their offer prices are below their relevant Regional Reference Price, or RRP.[22]

An implication of the unconstrained network policy is that obtaining a network access offer to connect to the SWIN involves lengthy delays – potentially well over two years. This is because in order to make a network access offer, Western Power needs to undertake both static network modelling and dynamic network modelling. These steps need to be undertaken sequentially, and each set of studies can take two to four months. Following network studies, Western Power needs to undertake an assessment of the cost of the work required to provide a network connection. This can take a further two to four months. Depending on the magnitude of work required to provide a network connection, Western Power may then need to proceed through the Regulatory Test process, and possibly receive approval for network investment from Western Power's board and the Minister.[23] Only 'major' augmentations[24] are required to satisfy the Regulatory Test, which is set out in Chapter 9 of the Access Code. The purpose of the test is to ensure that major augmentations to the covered network are

18 Western Power (2007a).

19 See, for example, ERA (2008a), p.7, and Western Power (2008), p.7.

20 Technical Rules 2.3.7.1(a).

21 See Western Power (2008), p.3.

22 See AEMC (2008a), p.vii and pp.7-8,

23 ERA (2008a), pp.18-19.

24 Above $16.2 million for the transmission network and above $5.4 million for the distribution network. These are 2007 (CPI-adjusted) dollars – see the ERA website at: http://www.era.wa.gov.au/2/537/48/_network_augment.pm. These amounts were originally $15 million and $5 million, respectively, in the Access Code.

properly assessed and found to maximise net benefits compared with alternative options, *before* the service provider commits to undertaking them.[25]

Even after an access offer is received, Western Power may need to undertake works to connect the applicant's plant. This may further extend the time taken before a prospective market participant is connected to the SWIN.

Under Western Power's Capital Contributions Policy, network applicants are required to make capital contributions to Western Power in respect of works that do not satisfy the new facilities investment test (NFIT).[26] The amount of contribution is meant to reflect the extent to which the forecast costs of the works allocated to the connection applicant exceed the likely amount of additional revenue gained from providing covered services to the applicant.[27]

2.1.2 Gas

Background

Western Australia has the largest gas reserves in Australia, with substantial offshore gas fields in the Carnarvon, Browse and Bonaparte basins. Western Australia's key gas infrastructure is illustrated in Figure 2.

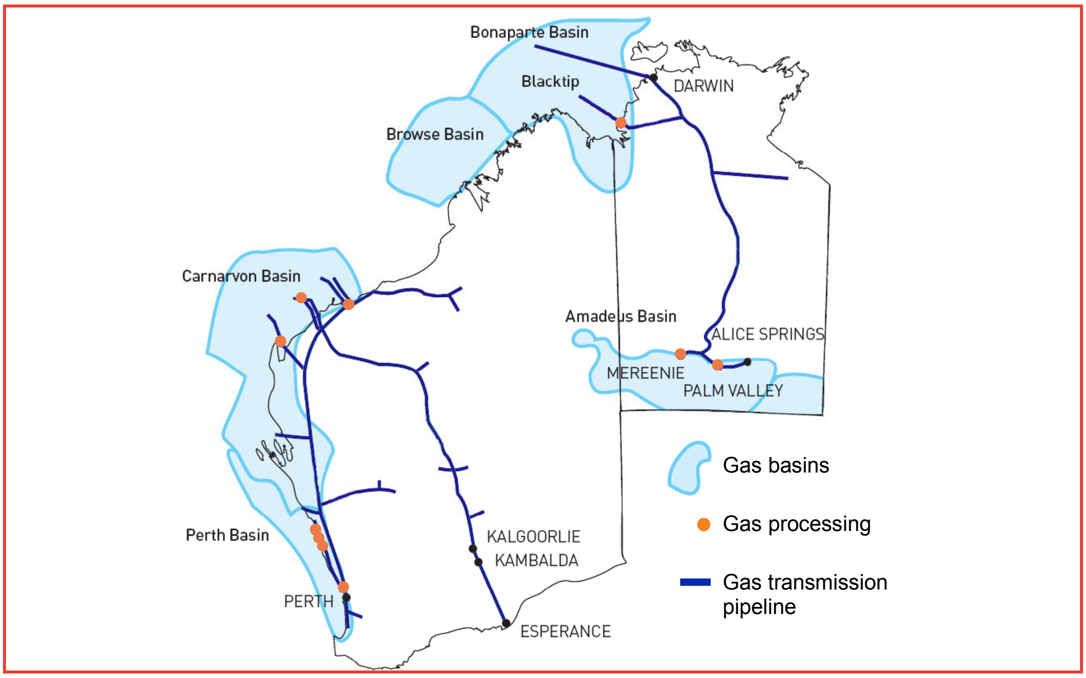

Figure 2: West Australian and Northern Territory gas infrastructure

Source: AER (2007), p.256.

[25] Access Code, subchapter 9.1.

[26] See Western Power (2007b) Clause 2 and Clause 2.9 of the Access Code.

[27] Western Power (2007b), clause 5.

In 2004/05, approximately 2% of total primary gas consumption in Western Australia was used for residential purposes, with the remaining 98% being used for commercial and industrial purposes.[28]

Due to the location of Western Australia's gas fields and the way the Western Australian gas market has developed, the domestic gas market remains reliant on a few major sources of supply and pipelines. This has had significant implications for the domestic gas market, with an increasingly tight supply-demand balance over the last few years as a result of the shortage of new volumes available for contract from existing producers. In response, the previous government developed a policy to require proponents of export Liquefied Natural Gas (LNG) projects to make the equivalent of 15% of LNG production available for domestic gas supply.[29]

The tight supply-demand balance has also exposed Western Australia to the risk that problems with existing infrastructure may substantially reduce the availability of gas, as demonstrated most recently by the explosion at Varanus Island on 3 June 2008.

Western Australia does not currently participate in the National Gas Market Bulletin Board[30] established by the Gas Market Leaders Group, although provision has been made for Western Australia and Northern Territory to join in the future. In addition, the Short-Term Trading Market proposed by the Gas Market Leaders Group has only been initially proposed for South Australia and New South Wales.

Market Structure

Upstream gas supply in Western Australia it currently quite concentrated. This reflects the fact that the major gas fields are located offshore and often in relatively deep water, so that development costs are substantial. The largest supplier of gas to the domestic market is the North West Shelf Joint Venture (NWSJV), which consists of Woodside, BP, Chevron, BHP Billiton, Shell and Japan Australia LNG. Gas from the NWSJV that is supplied to the domestic market is jointly marketed by the NWSJV. Far greater volumes of gas from this operation are exported to international markets in the form of LNG.

There are three transmission pipelines that supply the majority of gas used domestically in Western Australia. These are as follows:

- The Dampier to Bunbury Natural Gas Pipeline (DBNGP) runs from Dampier to Perth and then on to Bunbury, supplying gas from the Carnarvon basin to users in Perth and coastal regions in the southwest. The DBNGP is owned by a consortium consisting of DUET, BBI and Alcoa;
- The Goldfields Gas Pipeline runs from a compressor station on the DBNGP to Kalgoorlie in the goldfields (with another pipeline continuing on to

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28 ABARE (2006).

29 See http://www.doir.wa.gov.au/documents/DomGas_Policy(1).pdf

30 http://www.gasbb.com.au/aboutus.aspx

Esperence on the south coast). The GGP is majority owned by the APA Group; and

- The Parmelia pipeline runs from gas fields in the Perth basin to Perth. The Parmelia pipeline is 100 per cent owned by the APA Group.

Access to both gas transmission and distribution pipelines is regulated by the ERA. AlintaGas, owned by BBI, is the largest gas distributor in Western Australia. There are currently five gas retailers operating in the State: Alinta Sales (the incumbent retailer), Wesfarmers Kleenheat Gas, Worley Parsons Asset Management, Synergy and Origin Energy. Gas retailers to small customers must be licensed by the ERA. REMCo is the retail market administrator for the gas market in Western Australia.

The majority of gas consumed in Western Australia is used for the purposes of manufacturing, mining or electricity generation. Only very small amounts of the State's domestic gas is used for residential or commercial purposes. Gas used for the purposes of manufacturing or electricity generation is used predominantly in Perth and the coastal regions of Western Australia. Major users include Alcoa, (which operates alumina refineries in Kwinana, Pinjarra and Wagerup), BHP (which operates an alumina refinery at Worsley), Verve Energy (which operates a number of gas-fired generation plant in the SWIS) and Alinta (which operates gas-fired generation plant and retails gas to small and large users).

Gas used for the purposes of mining is used predominantly in the goldfields. Major users include WMC's nickel operations, BHP's iron ore operations, Anaconda's nickel operations and Newmont's gold mines.

Wholesale market arrangements

There is currently no formal wholesale gas market in Western Australia. The majority of gas is supplied under long-term agreements between gas suppliers and gas users. There are, however, two facilities for the short-term trading of gas in Western Australia: Trading capacity on the DBNGP and the Gas Bulletin Board.

Trading capacity on the DBNGP

Gas is delivered from the Carnarvon basin to Perth and other coastal areas along the DBNGP. It has been reported that access to capacity on the DBNGP can be a problem. While the pipeline has been regularly expanded over recent years[31] – through the addition of compression and looping – expansions tend only to occur when underwritten by a long-term contract.

Access to the DBNGP is regulated under the *National Gas Code* by the ERA. Under the access arrangement for the DBNGP, there is specified both a nominations process and a trade or transfer process:

- According to the nominations process, shippers must specify their nominations for a gas day by no later than 14:00 on the previous day. The

[31] http://www.dbp.net.au/about/

pipeline operator must notify the shippers of daily nominations for the gas day by no later than 16:00 on the previous day;

- According to the process for trading or transferring contracted capacity on the pipeline, if a shipper wants to trade or transfer contracted capacity, the operator of the DBNGP is required to notify other shippers of contracted capacity that is offered for trade. If a counterparty is found, and as long as the required conditions are met, this capacity can then be traded or transferred.

Gas Bulletin Board

Typically, short-term trade in upstream gas supplies has occurred informally between major users in Western Australia. However, following the Varanus Island explosion and the resulting shortage of gas supplies for the domestic market, a more formal gas bulletin board[32] was put in place by the IMO (separate from the one that recently commenced operation in the eastern states).

The Gas Bulletin Board provides a matching service whereby buyers and sellers whose bids/offers overlap are introduced to each other. Participation in the Gas Bulletin Board is voluntary. Initially, during the height of the gas shortage, a number of bids and offers were received on the Gas Bulletin Board for each trading day. Since the gas supply situation has improved, however, submissions to the Gas Bulletin Board have ceased.

Retail arrangements

Full Retail Competition (FRC) was introduced in the gas market in Western Australia in May 2004. However, competition in the retail gas market has been slow to develop. While there are currently five gas retailers licensed in Western Australia, Alinta Sales still dominates the retail market with over 99% market share.[33]

As part of the privatisation of AlintaGas in 2000, caps on gas tariffs for households and small business customers were introduced. Under the 2004 amended Tariff Regulations, the retail prices of gas to small use customers (households and small business customers using less than 1 TJ of gas per annum) are capped in the areas covered by the Tariff Regulations. This includes the Mid-West/South West (including the Perth metropolitan area), Albany, and Kalgoorlie-Boulder areas.

In their current form, the Tariff Regulations allow retailers to set their tariffs for new small use customers as they wish, so long as they offer at least one form of tariff under the tariff cap arrangements.

The Minister for Energy is currently conducting the Gas Tariffs Review to assess the tariff cap arrangements in Western Australia. As an interim step in the Review, the tariff cap was increased from 1 July 2008 by between 5.4 per cent and 16.5 per cent. A more detailed review will be undertaken for implementation

32 http://www.imowa.com.au/GasBulletinBoard.htm

33 ERA (2007a).

from 2009/10. The new government's position on the cost-reflectivity of retail tariffs is as yet unclear.

2.2 NORTHERN TERRITORY

2.2.1 Electricity

Background

The Northern Territory's electricity industry is small by eastern states' standards, reflecting its population of around 200,000. The Territory's key electricity infrastructure is illustrated in Figure 1. The Northern Territory consumed a total of 1,795GWh in 2007/08, or roughly 0.9 per cent of the NEM's annual consumption and 11 per cent of that consumed in the SWIS.[34] The Territory's electricity market is comprised of three relatively small, regulated systems[35]:

- Darwin to Katherine – with a combined regulated and unregulated capacity of 367MW and 5,360 km of power lines;
- Alice Springs – with a combined regulated and unregulated capacity of 91MW and 1,068 km of power lines; and
- Tennant Creek – with a combined regulated and unregulated capacity of 22MW and 477 km of power lines.

Over 99% of energy in the Northern Territory's regulated systems is generated using gas-fired plant.[36] In 2004/05, approximately 16% of total final electricity consumption in the Northern Territory was used for residential purposes, with the remaining 84% being used for commercial and industrial purposes.

Due to a lack of climatic suitability, the Territory has virtually no wind generation. However, both photovoltaic and thermal solar generation is used on a small scale in remote regions.

Regulatory arrangements

Regulation of the Territory's electricity supply and electricity network industries is the responsibility of the Utilities Commission. The specific responsibilities of the Utilities Commission with respect to a particular industry are assigned by provisions in the relevant industry regulation Acts. The relevant Acts applying to the electricity supply industry are:

- The *Electricity Reform Act*; and
- The *Electricity Networks (Third Party Access) Act*.

In particular, the Territory's electricity network industry is declared to be a regulated industry by the *Electricity Networks (Third Party Access) Act*, while the

34 NT Government (2008), p.6.

35 Utilities Commission (2008), p.1.

36 Utilities Commission (2007), p.25.

Territory's electricity supply industry is declared to be a regulated industry under the *Electricity Reform Act*.

The Utilities Commission's broad mandate is to ensure the promotion and safeguard of competition and fair and efficient market conduct. In the absence of a competitive market, the Utilities Commission aims to simulate the conditions of competition by preventing the misuse of monopoly power in the regulated markets for which it is responsible.[37]

Wholesale market arrangements

The Northern Territory electricity industry is dominated by a government-owned corporation, Power and Water Corporation (PWC), which owns the transmission and distribution networks and is responsible for power system control. PWC is also responsible for providing electricity generation and networks services in remote and regional communities. In some cases, PWC uses privately owned electricity networks and purchases wholesale electricity from IPPs, usually from mining companies.[38] PWC also relies on renewable generation, mainly in the form of solar technology, to supply more remote areas.

Average negotiated generation contract prices in the Territory appear to have increased over the last five years. Several possible explanations could lie behind this observation – the small scale of the Territory market, the lack of effective competition and a large reliance on higher-cost gas are all likely to be driving this increase. In addition, the NT Government is of the view that the Territory's regulatory framework does not provide sufficient incentives for the Territory's electricity industry to strive to identify efficiencies over time.[39]

The Northern Territory Government has approved a process of price oversight of PWC's generation business by the Utilities Commission for as long as competition, or the tangible threat of competition, does not arise. In April 2005, the Utilities Commission undertook a review and found that PWC's wholesale electricity generation prices were generally consistent with its estimates of the reasonable costs associated with generation in those years.[40]

Retail market arrangements

In 2000, the Territory Government commenced a phased introduction of retail contestability, originally scheduled for completion in April 2005. However, in light of NT Power's exit from the market in 2002 and PWC resuming its position as the monopoly retail provider, the Government suspended its retail contestability timetable in January 2003. This has effectively halted contestability

[37] http://www.utilicom.nt.gov.au/

[38] NT Government (2008), p.7.

[39] NT Government (2008), p.17.

[40] http://www.nt.gov.au/ntt/utilicom/electricity/wholesale_generation_pricing.shtml

at the 750 MWh per annum consumption threshold. The introduction of FRC is currently scheduled for April 2010.[41]

2.2.2 Gas

Introduction

Roughly 90% of natural gas in the Territory is used for electricity generation, with most of the remaining 10% being reticulated to commercial and industrial customers in Alice Springs and Darwin. In 2004/05, less than 1% of total primary gas consumption in the Northern Territory was used for residential purposes.[42] More recently, increasing quantities of gas have been exported as LNG. The three key gas reserves in the Territory are the Amadeus, Browse and Bonaparte basins. Wholesale gas market arrangements in the Territory, like in most states, tend to be dominated by confidential, long-term take-or-pay contracts. The National Gas Market Bulletin Board[43], an initiative of the Gas Market Leaders Group, does not currently operate in the Northern Territory. The Northern Territory's key gas infrastructure is illustrated in Figure 2.

Gas transmission

The Northern Territory's gas transmission and distribution networks are regulated by the AER. The Territory's principal transmission pipeline, the Amadeus Basin – Darwin System, is majority-owned by the APA Group[44] and is operated by NT Gas. The Amadeus Basin – Darwin pipeline is covered under the *Gas Access Code*, which has recently been superseded by the *National Gas Law* and *National Gas Rules*. Approximately 94%[45] of gas transported on this pipeline is used in the generation of electricity, with the remaining capacity being reticulated to industrial and residential users in Darwin and Alice Springs.

In addition to the covered Amadeus Basin – Darwin pipeline, the Territory has two uncovered pipelines:

- Palm Valley – Alice Springs is a 146km pipeline owned by Envestra; and
- Bayu-Undan – Darwin is an off-shore pipeline from the Bayu-Undan field in the Bonaparte basin to an LNG terminal located onshore near Darwin. This pipeline is operated by ConocoPhillips and its supply is currently used exclusively for export LNG.

In addition, the APA Group has proposed to construct a pipeline from the Blacktip Gas Plant, which is connected to the offshore Blacktip field in the Bonaparte basin, to a connection point with the existing Amadeus Basin –

41 AER (2007). p.213.

42 ABARE (2006).

43 http://www.gasbb.com.au/

44 The APA Group comprises the Australian Pipeline Trust and the APT Investment Trust.

45 http://www.pipelinetrust.com.au/4/4-4.html

Darwin pipeline at Ban Ban springs. Gas supplied from this pipeline is expected by 1 January 2009.[46]

Retail market arrangements

As noted above, the overwhelming majority of 'covered' gas in the Northern Territory is used in the generation of electricity, with the balance being reticulated to industrial users in Alice Springs and Darwin. As such, the Territory has a very small residential retail base.

There are two primary gas retailers in the Northern Territory – Envestra and NT Gas. Envestra retails gas in the Alice Springs area, while NT Gas reticulates small quantities to commercial customers in Darwin's industrial areas.

The Northern Territory's retail gas market is currently fairly tight – all available gas is currently contracted to 2009[47]. While the lack of gas availability has likely precluded entry into the retail gas and wholesale electricity market in the Territory, the supply of gas from the Blacktip field in the Bonaparte basin (due to begin flowing in January 2009) is expected to ease supply-side constraints and promote entry into these markets.

The Northern Territory Government introduced FRC into the Territory's gas market in October 2001. However, unlike in other states that have also introduced FRC, the Northern Territory did not appoint an incumbent 'franchise' retailer, primarily due to the Territory's lack of significant residential gas customers.[48]

[46] http://www.pipelinetrust.com.au/4/4-8set.html

[47] AER (2007), p.288.

[48] AER (2007), p.291.

3 Generic effects of climate change policies

3.1 INTRODUCTION

This section begins by defining and explaining the Government's two primary climate change policies: the CPRS and the expanded national RET scheme. Section 3.3 goes on to describe the generic effects that each of these policies is likely to have on energy markets in general, particularly within Australia. The impact these policies are likely to have on the specific energy markets of Western Australia and the Northern Territory is discussed in section 4.

3.2 CLIMATE CHANGE POLICIES

3.2.1 Carbon Pollution Reduction Scheme

The CPRS is a 'greenhouse gas' emissions cap-and-trade scheme, scheduled to commence in 2010, aimed at reducing Australia's emissions in the long term. In the energy sector, the scheme is essentially a tax on greenhouse gas emissions to change the relative cost structure of generation, in order to favour cleaner plant. The scheme aims to achieve emissions reductions at least-cost by:

- Capping emissions through the allocation of emission permits; and then
- Allowing participants to freely trade these permits between themselves.

The long run emissions reduction pathway is achieved by progressively reducing the number of permits in circulation. At this stage, the CPRS aims to cut Australian emissions to 60 percent of 2000 levels by 2050.[49]

The Government has proposed that the CPRS will cover roughly 75 percent of Australia's emissions and will involve approximately 1000 firms, each of who emit more than 25,000 tonnes of carbon dioxide-equivalent (CO_2-e) pollution per year. The Government has proposed that the CPRS will include the six gases covered by the Kyoto Protocol (i.e. *carbon dioxide, methane, nitrous oxide, sulphur hexafluoride, hydrofluorocarbons, and perfluorocarbons)* and will cover the following industries:

- Stationary energy;
- Transport;
- Fugitive emissions;
- Industrial processes; and
- Waste; and

In addition, agriculture is proposed for inclusion from 2015, while forestry can opt-in and create offsets, but will be liable for these offsets if they later reduce their stock of stored emissions.

[49] Australian Government (2008a), p.8.

At this stage, the Government has not released specific interim pollution reduction targets or forecast carbon prices. The most relevant estimate of carbon prices in the infant stages of the CPRS is the Garnaut Report's proposal for prices to be fixed at \$20/t CO_2-e and escalated at CPI+4% annually over the transition period 2010-2012.[50] Details of the Government's proposed CPRS can be found its July 2008 Green Paper.[51]

3.2.2 The expanded national RET scheme

The Government's proposed expanded national RET scheme aims to consolidate and extend several State and Commonwealth-based renewable energy targets, both existing and proposed. These schemes are summarised in Table 1. A comparison of the targets is provided in Figure 3.

Existing renewable energy targets		
Jurisdiction	*Scheme*	*Comment*
National	MRET	Requires retailers of electricity to purchase 9,500 GWh of renewable electricity each year by 2010 (until 2020).
Victoria	VRET	Renewables target in Victoria of 10% by 2016 – additional 3,274 GWh. Ramps down to 2030 (15 yr limit per project).
NSW	NRET[52]	Renewables target in NSW of 10% by 2010 (additional 1,317 GWh) and 15% by 2020 (additional 7,250GWh).

Proposed renewable/clean energy targets		
Jurisdiction	*Scheme*	*Comment*
South Australia	SARET	Renewable target of 20% by 2014 has been enacted, but no scheme is yet in place.
Western Australia	WARET	Climate change policy includes a renewable target of 15% by 2020 and 20% by 2025.
Queensland	QLET	Climate change policy includes a renewable/low emissions target of 6% by 2015 and 10% by 2020.

Table 1: Summary of renewable/clean energy targets

Source: Frontier Economics

50 Garnaut (2008), p.350.

51 Australian Government (2008a).

52 The Renewable Energy (New South Wales) Bill 2007 has been introduced to Parliament, but the legislation is currently on hold pending the outcome of the expanded national RET design process.

Broadly speaking, the expanded national RET scheme aims to ensure that at least 20 percent of Australia's electricity supply (approximately 60,000 GWh) is generated from renewable sources by 2020. This will involve increasing existing renewable energy targets to 45,000 GWh. In conjunction with approximately 16,000 GWh of pre-MRET renewable generation,[53] this will achieve the stated target.

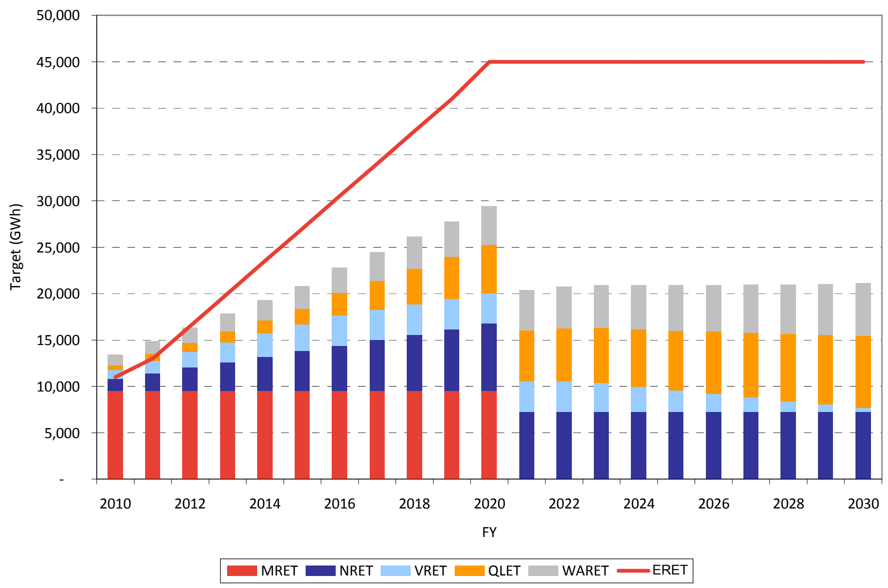

Figure 3 Summary of renewable energy targets

Source: Frontier Economics

The expanded national RET scheme guarantees a market for additional renewables-based generation (backed by a legislative obligation), using a mechanism of tradeable Renewable Energy Certificates (RECs). Demand for RECs is created by legally obliging parties who buy wholesale electricity (retailers and large users) to source an increasing percentage of their electricity purchases from renewables-based generation in the form of annual targets.

The expanded national RET scheme is designed to increase the deployment of renewable energy in Australia's electricity supply in the short to medium term. The scheme will be phased out between 2020 and 2030, by which time it is expected that pricing signals emanating from the CPRS will be sufficient to encourage investment in renewable generation going forward. Details of the Government's proposed expanded national RET scheme can be found in its consultation paper.[54]

53 This comprises primarily of output from Snowy and Hydro Tasmania plant.

54 Australian Government (2008b).

3.3 GENERIC EFFECTS OF THE CPRS

The direct effect of the CPRS on Australia's energy markets will be to increase the cost (other things being equal) of using emissions-intensive energy sources, such as coal and gas, including for the purposes of electricity generation. The consequential effects of the CPRS on Australia's electricity and gas markets are discussed below.

3.3.1 Impact on electricity market structures and arrangements

As a result of increasing the cost of emissions-intensive generation fuel sources, the CPRS will tend to increase the wholesale price of electricity. To the extent increases in wholesale prices are reflected in higher retail prices, electricity demand is likely to grow more slowly (or possibly decline) than would otherwise be the case. In addition, the production of electricity is likely to switch, over time, from high emissions generation technologies and fuels to low and zero emissions technologies and fuels. In terms of baseload generation, this implies that investment in natural gas-fired generation should increase relative to coal-fired generation, other things being equal.

Impact on baseload generation

In the short to medium term, CO_2-e abatement in the electricity industry is likely to be dominated by fuel shifting[55] from coal to gas. This shift is driven by the relatively low emissions-intensity of gas-fired versus coal-fired plant, as well as due to the limited availability of alternative technologies for low emissions generation. Carbon capture and sequestration (CCS), geothermal and solar thermal are all immature technologies and are currently much higher-cost alternatives. Renewables are also much higher cost than gas, and would require carbon permit prices in excess of \$50-60/t CO_2-e before becoming viable in their own right (in the absence of the expanded national RET scheme). Demand-side response is also likely to be limited in at least the short to medium term due to relatively inelastic demand for electricity.[56]

The inverse of the slope in Figure 4 below represents the cost of abatement for *new* investment in the NEM. At higher gas prices, this curve becomes flatter (i.e. CCGT technologies would be shifted to the right due to higher Long-run Marginal Costs, or LRMCs) which indicates that the cost of abatement is higher.

The effect of sunk capital costs is also important in this regard. The marginal operating cost of existing plant with sunk capital costs is less than the LRMC of new plant without sunk costs. As such, existing plant would plot to the left of those shown in Figure 4, thereby indicating that fuel-shifting from existing coal

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[55] Fuel shifting here refers to the increase in the use of gas relative to coal for electricity generation as a result of changes in new investment from coal-fired to gas-fired generation. It is not intended to suggest that coal-fired generators will run on gas.

[56] See, for example: http://www.nemmco.com.au/about/419-0026.pdf. In the longer term, the lower future emissions-intensity of electricity generation will likewise reduce the abatement benefits of demand-side response.

plant to new gas plant would be a higher cost abatement option than shifting from new coal to new gas plant.

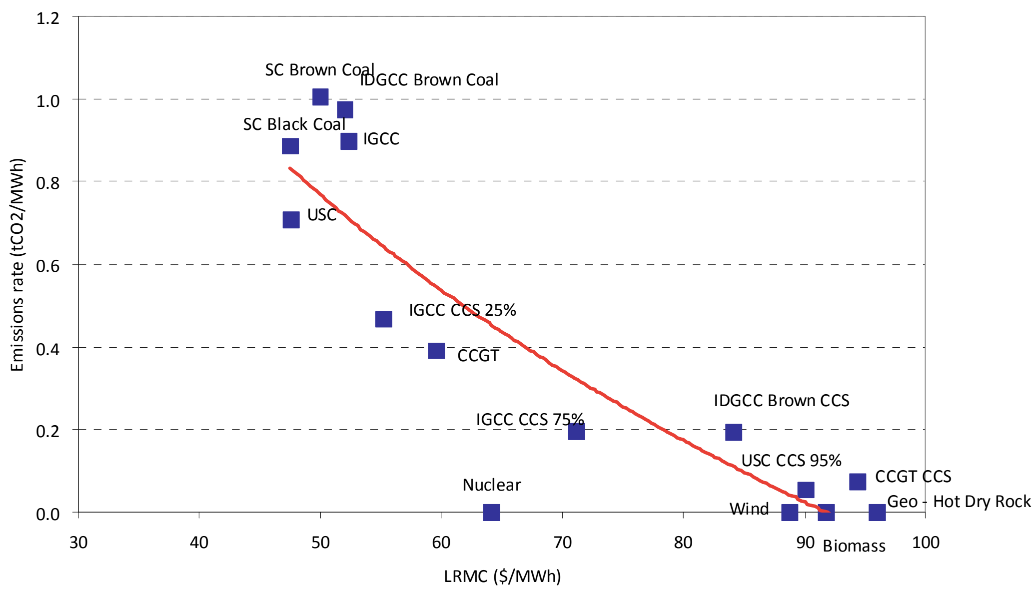

Figure 4: LRMC and emissions intensity trade-off

Source: Frontier Economics

This observation raises an important interdependency in the short to medium term between the price of coal- and gas-fired generation and the price of permits under the CPRS. Given that fuel shifting is the main abatement option in the electricity sector in the near term, the price of permits will be intimately related to the difference in cost between coal and gas plant. That is, to induce the necessary abatement from this sector, permit prices will continue to rise to the point where fuel shifting becomes cheaper than buying permits to cover the incremental emissions from coal-fired generation.

This result comes from the necessity for coal-fired generation to be displaced by gas-fired generation, and hence for there to be a re-shuffling of the generation merit order, in order to bring about the necessary levels of CO_2-e abatement in the near term. Consider the following simple example.

Plant	Initial SRMC ($/MWh)	CO_2 Intensity (tCO_2-e /MWh)	Carbon Cost ($/MWh)	New SRMC ($/MWh)
Hydro	2	0.0	0	**2**
Coal	10	1.1	35	**45**
Gas	25	0.6	19	**44**

Table 2: Merit order re-shuffle: Low gas prices

Source: Frontier Economics

Table 2 outlines the Short Run Marginal Cost (SRMC) of three generating technologies, along with a measure of each technology's CO_2-e intensity. In this example, assume a carbon price of $32/tonne CO_2-e. Under the CPRS, a carbon-emitting generation plant will see an increase in its SRMC equal to the cost of carbon it emits. The cost of carbon is determined by multiplying the price of carbon by the CO_2-e intensity of that technology. The merit order for this stylised example pre- and post- CPRS is depicted in Figure 5.

This example illustrates how permit prices under the CPRS would have to rise to the point where, adjusted for their relative CO_2-e emissions per MWh, gas-fired generation becomes cheaper than coal-fired generation such that gas-fired generation displacing coal-fired generation in the merit order. Thus while a permit price of $28/t CO_2-e does not result in coal displacing gas (at $28/t CO_2-e, coal's SRMC is $41/MWh compared to gas's $42/MWh), a permit price of $32/t CO_2-e does cause the required substitution to occur.

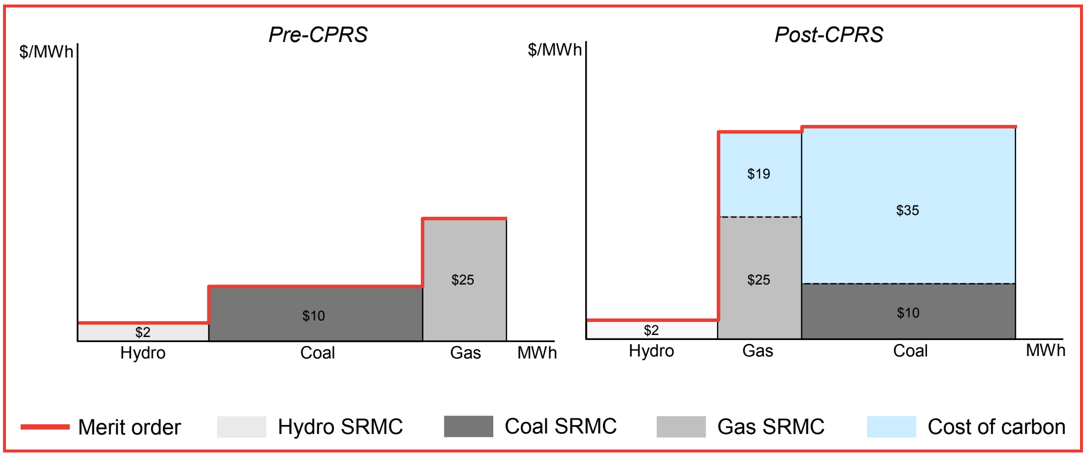

Figure 5: Merit order re-shuffle: Low gas prices

Source: Frontier Economics

A consequence of this process is that the relative cost difference between coal- and gas-fired generation prior to the introduction of the CPRS will determine the price of emissions under the CPRS in the short to medium term, and hence the eventual wholesale price of electricity. This is due to the lack of alternative abatement options other than fuel shifting over this period.

Plant	Initial SRMC ($/MWh)	CO_2 Intensity (tCO_2-e/MWh)	Carbon Cost ($/MWh)	New SRMC ($/MWh)
Hydro	2	0.0	0	**2**
Coal	10	1.1	46	**56**
Gas	30	0.6	25	**55**

Table 3: Merit order re-shuffle: High gas prices

Source: Frontier Economics

To illustrate this result, Table 3 reproduces the same information as Table 2. However, in this case, the SRMC of gas-fired generation is assumed to be \$30/MWh instead of \$25/MWh. This implies that the cost difference between coal- and gas-fired generation is greater *ex ante* CPRS in this scenario (\$15/MWh versus \$20/MWh).

In this example, the emissions price necessary to force fuel shifting from coal to gas is \$42/tonne CO_2-e. A price of \$38/tonne CO_2-e does not result in coal displacing gas (at \$38/tonne CO_2-e, coal's SRMC is \$52/MWh compared to gas's \$53/MWh) while a permit price of \$42/tonne CO_2-e does cause the required shift. This outcome is illustrated in Figure 6.

Importantly, as is evident from the above examples, a \$5/MWh greater spread between the respective SRMCs of coal- and gas-fired generation results in a \$10/tonne CO_2-e higher permit price.

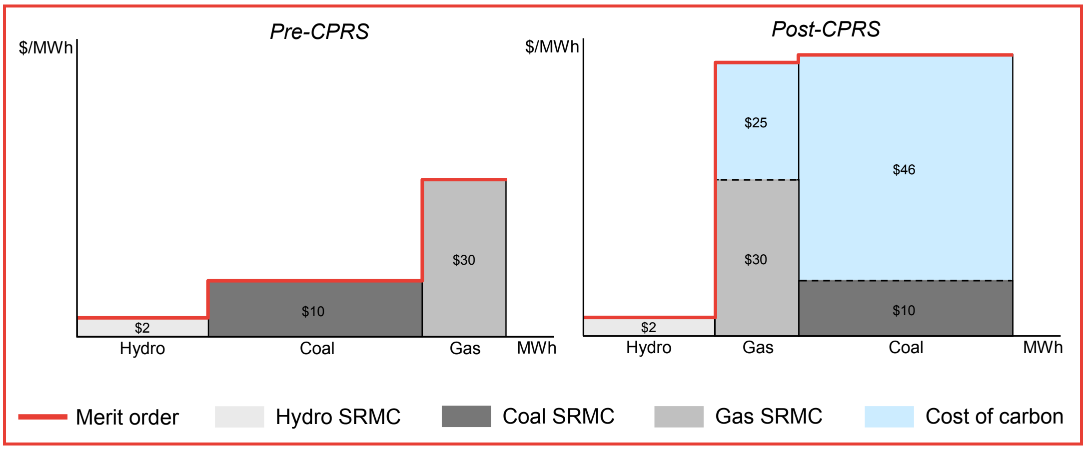

Figure 6: Merit order re-shuffle: High gas prices

Source: Frontier Economics

Impact on renewable generation

In the long term, the CPRS will encourage investment in zero- and low-emission generation technology, due to the ramping up of permit prices. While shifting from coal to gas might be the cheapest option for abatement, doing so will only reduce emissions output by a finite amount[57]. In the longer-term, the implied trajectories for emissions will require far more substantial cuts, and hence the need for renewable generation or sequestration, even if these represent more costly abatement options. However, the pricing signals necessary to incentivise such investment will take considerable time to eventuate due to the relatively high (present) cost of these technologies. As such, renewable generation investment in the short to medium term will be driven primarily by the expanded national RET scheme.

[57] For the examples above, fuel shifting can reduce emissions by a maximum factor of ((0.6 t CO_2-e/MWh) - (1.1 t CO_2-e/MWh))/(1.1 t CO_2-e/MWh) ≈ 45%.

Impact on retail market arrangements

To the extent that the CPRS results in increased wholesale electricity prices, retail market arrangements may need to be reviewed to ensure the viability and financial liquidity of electricity retailers. Wholesale electricity costs comprise a large proportion of retailers' costs. To remain liquid and viable, retailers will need to be able to pass through these costs to end-use consumers. The extent to which cost pass-through is possible will typically depend on the speed of adjustment of regulated retail tariffs. Thus, to ensure the financial viability of existing retailers and to encourage entry into retail markets going forward, regulated retail tariffs may need to be reviewed to accommodate higher wholesale energy prices post-CPRS introduction.

Impact on financial position of market participants

A potentially important consequence of the CPRS on Australia's electricity markets is the impact the policy may have on the valuation of existing generation assets. Without some form of transitional compensation, generators have argued that write-downs of the accounting value of a number of existing generation assets is possible.[58]

To they extent they occur, such write-downs raise implications for the financing and hedging strategies of participants, particularly for generators in the NEM. In the event that significant valuation write-downs occur, the marking-to-market of affected generation assets may trigger provisions in financing arrangements, which in turn could result in reductions in the size of permissible loans, the length of time for loans to be repaid, or the cost of servicing such loans post re-financing. Additionally, significant asset write-downs may trigger clauses in bilateral and hedge contract agreements due to credit downgrades, which in turn have the potential to lead to withheld payments under such agreements, exposing participants to spot market prices. Due to the interrelated nature of hedging arrangements, this process could potentially spread across multiple market participants. In an *extreme* case, such 'default contagion' could pose a threat to the integrity and stability of the market.

The CPRS is also likely to increase the prudential risks faced by participants, due mainly to the higher and potentially more volatile wholesale electricity prices expected under the policy. The extent to which participants are able to absorb such increased risk will depend mainly on their existing financial position. Increased prudential requirements may threaten the stability of smaller market participants who may be less able to absorb such risks.

Energy security

To the extent that the CPRS leads to a greater reliance on gas generation to meet electricity demand, there is a question as to whether there will be a greater energy security issue in terms of the reliability and security of power supplies. Gas transportation networks are typically not built to provide for the same level of

[58] ESAA (2008), p.4.

redundancy as the electricity transmission network. This means a single point of failure in the gas network, be it at a processing plant or a pipeline, may have sever implications for electricity supply. Apart from the recent Varanus Island explosion in Western Australia, a key example of this potential vulnerability is the 1998 Longford gas explosion, which led to a virtually complete curtailment of gas supplies for Victorians for approximately two weeks. To the extent that the CPRS leads to a greater dependency of electricity generation on gas supplies, such events could lead to an increased risk of load shedding in the future.

Impact on current investment climate

The current uncertainty surrounding the details of the CPRS is likely to be deterring or delaying prospective private generation investment, particularly in coal-fired generation. This could ultimately have implications for system reliability. Resolution of a detailed investment path into the future, and hence emissions targets going forward, will help resolve such uncertainty and ease these effects.

3.3.2 Impact on gas market structures and arrangements

The effect of the CPRS on Australia's gas markets will be to increase the demand for natural gas, other things being equal. This increased demand will be primarily driven by increased investment in gas-fired generation, due to its lower CO_2-e emissions intensity as compared to coal-fired generation.

Impact on the price of natural gas

The increasing demand for natural gas as a result of increasing carbon prices will, *ceteris paribus*, drive up the price of natural gas in Australia. The extent to which this occurs, however, is largely dependent on two factors. These are:

- The availability of natural gas (which will affect the own-price elasticity of supply of gas); and
- The extent to which prices in domestic markets for natural gas are set according to international prices for LNG.

Australia has vast reserves of natural gas located in both the eastern and western regions of the country. This suggests that the price elasticity of supply for domestic natural gas should be fairly high, or elastic, and that shortages of natural gas are unlikely to lead to significant price increases going forward. The availability of supply in the near term may be constrained, however, by well capacity and/or transmission and distribution infrastructure. For example, gas transmission constraints arise in the Victorian network, particularly at peak winter times.[59] However, in the medium term, these constraints could and are being alleviated through capacity expansions. It is thus likely that growing domestic demand for natural gas will place only moderate upward pressure on gas prices going forward.

[59] See VENCorp (2008), pp.8-9.

In the last few years, gas has been significantly re-priced due to the ability of LNG to substitute for oil, which has itself experienced dramatic price increases. Domestic gas markets that are currently exporting natural gas as LNG are exposed to international demand and supply conditions, and hence non-contracted gas in such markets has a lower-bound domestic price equal to the prevailing export price, which is set by international forces. By contrast, domestic markets that are removed from international markets due to a lack of (or constrained) LNG facilities and/or physical interconnection with a market that does posses LNG export capacity experience gas prices that are set more by local supply and demand conditions in that market.

As a general observation, markets separated from international forces are likely to see domestic demand driving up the price of gas to a greater extent than markets exposed to international gas prices. This is because participants in markets exposed to international forces will, to a large extent, be price-takers in international markets. This issue is further discussed in section 4.2 below.

Impact on gas market infrastructure

The increased demand for natural gas going forward is likely to place increased pressure on gas transmission and distribution networks. To address this growing demand, network augmentations may need to be made. The augmentation of these networks will require considerable capital expenditure, which will place additional costs on the system. In the absence of such augmentations, the incidence of gas constraints on transmission pipelines would be expected to rise, imposing its own efficiency-related costs on the gas (and ultimately the electricity) markets.

Impact on retail market arrangements

As was the case with electricity retail market arrangements, to the extent that the CPRS results in higher wholesale gas prices, regulated retail gas tariffs may need to be reviewed and adjusted. Failure to do so may compromise the financial viability of existing gas retailers and deter entry into the gas retail market going forward.

3.3.3 Summary

The key impact of the CPRS will be to increase the cost of supplying electricity from greenhouse gas emissions-intensive generation technologies. This increased cost will tend to encourage greater demand and supply of gas-fired generation relative to coal-fired generation.

The extent to which the relative attractiveness of gas-fired electricity generation forces the price of natural gas up will depend on the availability of domestic gas supplies, and the extent to which domestic markets are exposed to international gas prices. The growing demand for natural gas is likely to place greater pressure on existing gas infrastructure, which may require network augmentations at considerable cost going forward.

To the extent that wholesale electricity and gas prices increase due to the CPRS, retail market arrangements in these markets may need to be reviewed to allow the appropriate pass-through of costs from retailers to end-use customers.

In the longer term, due to the substitution away from emissions-intensive technology, there will be growing demand for low- and zero-emission generation alternatives. The extent to which the demand for renewable generation increases in the short to medium term, however, will depend more on the expanded national RET scheme than the CPRS.

3.4 GENERIC EFFECTS OF THE EXPANDED NATIONAL RET SCHEME

The direct effect of the expanded national RET scheme on Australia's energy markets will be to increase the demand for RECs. The consequential effects of the expanded national RET scheme on Australia's electricity and gas markets are discussed below.

3.4.1 The economics of the expanded national RET scheme

Through its construction, the expanded national RET scheme aims to increase the financial reward from supplying renewable generation. This is achieved by paying renewable generation a REC price in addition to revenues received in the spot market. Provided that total revenue received exceeds the LRMC of supply, renewable generation (such as wind) will be built. Once built, such plant have incentives to offer energy to the market at SRMC, which in the case of wind generation is negligible.

As such, wind generation should be dispatched to displace non-renewable generation in the merit order. The difference between the *marginal* renewable plant's LRMC (i.e. the plant only just able to enter the market) and the average spot price received in the wholesale market will be the REC price paid under the scheme. This process has been modelled representatively in Figure 7.

This example considers a wind plant that has an LRMC of $70/MWh. At an average spot price of $36/MWh this plant would not be built, and not dispatched, without a REC payment. Providing this plant with a stream of revenue in addition to its average wholesale earnings in the form of a REC payment encourages this plant's entry into the market. Once built, this plant offers its generation to the market at a negligible cost, reflecting its very low SRMC, and hence displaces non-renewable generation in the merit order. The REC price thus represents the difference between the average wholesale spot price received by this plant ($36/MWh) and the average LRMC of this plant's supply ($70/MWh) – in this example the REC price is $34/MWh.

All else being equal, the renewable energy target under the scheme sets the demand for RECs (and hence for renewable generation), which in turn sets the REC price depending on the supply of renewable generation. As such, a low target results in a low REC price, since only the most productive (lowest cost) renewable generation will enter the market. By contrast, a high target would encourage more marginal (higher cost) renewable plant to enter, and hence REC prices would be higher.

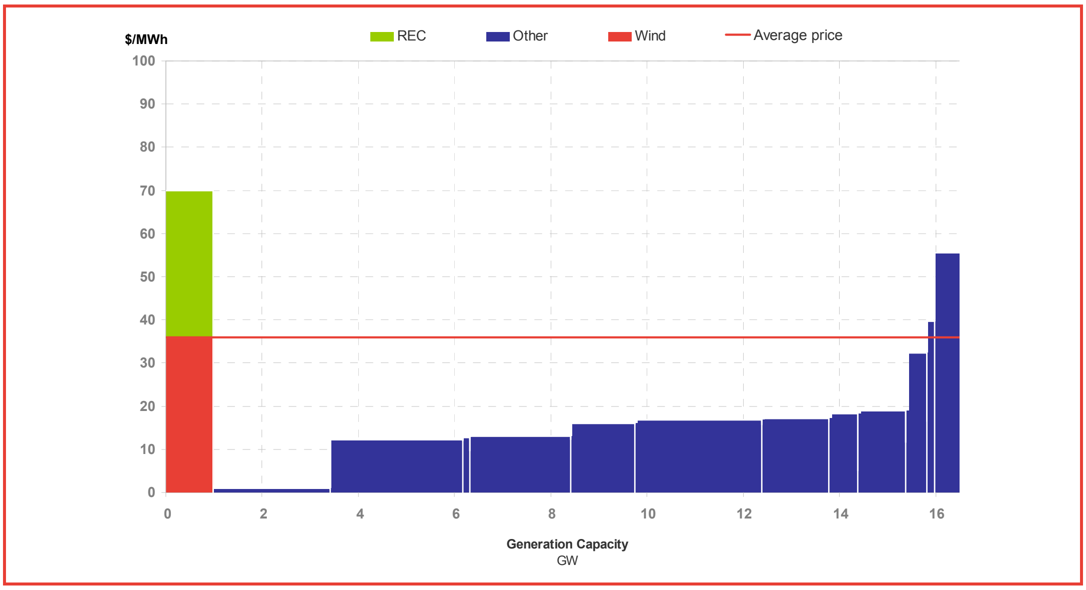

Figure 7: Determination of REC prices

Source: Frontier Economics

3.4.2 Impact on electricity market structures and arrangements

By creating a demand for RECs, the expanded national RET scheme will tend to increase the quantity of renewable generation capacity. This is because RECs provide renewable generation proponents with a stream of revenue in addition to that derived from the wholesale electricity market. By mandating that retailers must cover a certain quantity of their load obligations through the purchase of RECs, the expanded national RET scheme effectively subsidises renewable generation technologies (such as wind) relative to carbon-emitting generation technologies (such as coal).

As noted above, retailers and large users are required to acquire RECs. Retailers will seek to recover these costs through higher retail tariffs. To the extent they cannot do this due to price regulation, their financial positions may be worsened. This may reduce entry into the retail market, and could adversely affect retail electricity competition.

More directly, an increase in renewable generation may have a number of negative risks and implications for electricity markets, particularly for the maintenance of power system security. Most of these implications are attributable to the intermittent and unpredictable nature of key renewable sources, such as wind. Specifically, an increase in wind generation can have implications for:

- Power flows violating secure network limits;
- Forecasting of demand and supply conditions;
- Minimum generation levels of thermal plant;

- Frequency control ancillary services;
- Reserve plant margin;
- Network planning and investment; and
- Generation connection costs and technical standards.

These implications are discussed in more detail below.[60] We note that while in the medium term the expanded national RET scheme will increase the quantity of wind generation capacity in Australia, in the longer term geothermal and solar thermal technologies may increasingly play a role in Australia's renewable generation portfolio. Geothermal technology, and to a lesser extent solar thermal technology, is more suitable in meeting baseload generation needs than wind (as it is less intermittent), and hence in the longer term some of these issues may be partially mitigated.

Impact on power flows and secure network limits

The intermittent nature of much renewable generation can compromise the system operator's ability to keep power flows within thermal, voltage and stability limits, which can potentially jeopardise system security. In response, system operators may need to increase safety margins within network constraint equations, or invoke more frequent directions to participants, both at the cost of operational efficiency and good regulatory practice. Alternatively, system operators may need to impose some operational constraints around the output of renewable plant. For example, in the NEM, the AEMC has recently approved a modified version of NEMMCO's proposed 'semi-scheduled dispatch' Rule change (SSD Rule Change). [61] The final accepted SSD Rule Change, *inter alia*:

- Created a new registration category for 'Semi-Scheduled Generators' for intermittent plant over 30 MW nameplate capacity and allowing for some aggregation;[62]
- Allowed NEMMCO to formulate constraints with Semi-Scheduled Generator units on the left-hand (controllable) side of the constraint equation;[63]
- Required Semi-Scheduled Generators to limit their output below a unit-based dispatch level set by NEMMCO, but only during dispatch intervals in which a higher level of generation could lead to the violation of secure network limits or in the case where the intermittent plant was constrained-off;[64] and

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[60] A good, if slightly dated, introduction to these issues in the context of the NEM is contained in a Discussion Paper prepared by the Wind Energy Policy Working Group for the Ministerial Council on Energy Standing Committee of Officials entitled, "Integrating Wind Farms into the National Electricity Market", March 2005.

[61] AEMC (2008b), pp.12-13.

[62] SSD Rule Change, pp.27-37.

[63] SSD Rule Change, p.44.

[64] SSD Rule Change, pp.50-52.

- Allowed Semi-Scheduled Generators to bid inflexible and subject to ramp rate constraints, but applies the same rebidding restrictions as for Scheduled Generators.[65]

Impact on forecasting of demand and supply conditions

System operators typically seek to forecast demand and supply conditions in order to ensure there is sufficient capacity to reliably serve load for the foreseeable future. To the extent that intermittent plant are not required to submit information about their expected availabilities to the system operator, this could compromise the integrity of these forecasts and ultimately impose higher costs and/or risks of unserved energy on consumers.

In response, in the NEM, the SSD Rule Change:

- Requires Semi-Scheduled Generators to submit plant availability to NEMMCO for the purposes of the Unconstrained Intermittent Generation Forecast (UIGF), but not separately for the purposes of PASA or pre-dispatch;
- Requires Semi-Scheduled Generators to notify NEMMCO of changes in their availability greater than 6 MW of registered capacity; and
- Requires NEMMCO to produce the UIGF (using data from Semi-Scheduled Generators and other inputs such as wind velocity) to help predict likely intermittent generation ('available capacity') for the purposes of PASA and pre-dispatch.

It should be noted that the SSD Rule Change followed a previous change to the *National Electricity Code* in 2005 that sought to increase the level of disclosure about historical and forecast quantities of unscheduled generation.[66] The additional information required under the Rule change relates to aggregated regional generation values for non-scheduled generation in the MT PASA, the ST PASA and pre-dispatch forecasting processes. Additionally, NEMMCO is required to publish aggregated actual non-scheduled generation values for each dispatch interval and actual non-scheduled generation values for each trading interval.

Impact on operation of thermal plant

The requirement under the national expanded RET scheme that a given proportion of energy production is provided by renewable sources implies that thermal generation will be replaced to some extent by renewable generation. In the short term, this will tend to reduce the operating efficiency of thermal plant. At the extreme, thermal plant may be limited to their minimum stable generation levels at low load times (such as overnight). If the system operator cannot curtail the output of renewable plant, it may even be necessary for thermal plant to shut down at low load times. This is unlikely to be practicable on a routine or regular

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[65] SSD Rule Change, pp.39-42

[66] AEMC (2006).

basis and even if it does occur, there are likely to be significant lags in bringing the thermal plant back on line when they are needed, such as the following day.

In response, most system operators seek to curtail renewable plant output when conventional thermal plant are approaching minimum stable levels. Depending on the technology of the renewable (say, wind) plant concerned, such curtailment can be achieved by, for example, making adjustments to the angle of the blades on wind turbines. To the extent that this results in renewable plant running less than they can, this has clear implications for the economics of renewable plant.

In the medium to long term, an increase in wind output would be expected to lead to less thermal capacity being developed. However, as much renewable capacity cannot be provided on demand, this will have implications for system reliability and the required level of reserve.

Impact on reserve plant margin

The intermittent nature of renewable generation sources such as wind can increase the requirements of reserve plant for ensuring system reliability and security.

To ensure reliability and security, most power systems around the world operate with a capacity reserve margin (CRM) of about 15-25% (i.e. available generation capacity equals or exceeds forecast peak load plus 15-25%).[67] In some markets, generators are paid explicitly to make their capacity available to the system.

While conventional thermal generators are typically able to generate, on average, 90-95% of their rated capacity over the course of a year, the same figure for wind generators is only about 30-45%. Furthermore, the *reliably available* output of wind generators at any point in time is generally much less than the *average* contribution of wind plant. For example, NEMMCO assumes wind farm contribution factors, defined as the fraction of installed capacity assumed to be available at the time of regional maximum demand, for each NEM jurisdiction for summer and winter.[68] The assumed wind farm contributions range from 0 per cent in New South Wales for both seasons to 23 per cent in Victoria for summer. NEMMCO's Reserve Outlook assumes an average reliable capacity in the NEM of 8 per cent.[69] ESCOSA assumes available capacity of 7-8 per cent at the time of South Australia's regional peak demand.[70] This means that, other things being equal, an increase in wind capacity means that the power system's reserve margin (including intermittent plant capacity) will have to be increased to maintain the existing level of system security and supply reliability.

To the extent an increase in required reserve occurs, increased investment in standby generation, such as gas turbines or pump storage hydro plant, will be

[67] NEMMCO (2005), p.3.

[68] NEMMCO (2007), Table 3.47, p.3-47.

[69] NEMMCO (2008), p.5.

[70] ROAM (2007), p.6.

required. However, the degree of additional required reserve is likely to be limited by:

- The proportion of intermittent renewable plant in the total system – the required reserve margin (including intermittent plant) will only increase if the proportion of renewable plant in the total system is high relative to conventional generation; and
- The availability to import/export power to other systems – power systems with high wind penetrations that are interconnected with other systems, such as Denmark, have the ability to benefit from reserve-sharing. By contrast, isolated systems cannot benefit from access to reserve generation capacity of neighbouring connected systems. In the absence of back up from neighbouring systems, these systems are more vulnerable to reliability issues and frequency instability.[71]

Impact on Frequency Control Ancillary Services

To maintain power system frequency within required bounds, system operators must adjust the output of generators to match moment-by-moment variations in the demand of loads and supply from generators. The integration of intermittent generators into the system, the output of which may vary rapidly and unpredictably, generally makes the task of frequency control more difficult. An increase in intermittent generation may therefore increase the requirement for Frequency Control Ancillary Services (FCAS), such as regulation (or load-following) reserve, to maintain system frequency within required bounds.

Currently in the NEM, the costs of regulation FCAS are recovered from market participants according to the 'Causer Pays' methodology.[72] In the SSD Rule Change, the Commission provided that the costs of regulation services are allocated to intermittent plant to the extent they are unable to reach their dispatch levels based on a straight-line trajectory during a dispatch interval. This decision was based on the view that intermittent generators ought to face the full costs their presence imposes on the rest of the power system, in order to encourage an efficient mix of generation investment in the NEM.[73]

Impact on voltage control

Variations in load and output lead to voltage variations, which can in turn cause interference or damage to users' equipment. A large variation in the power output of a generator will cause voltage swings at the connection point and nearby points due to changing current flows in the system lines and transformers. A system operator's task of minimising generation (and hence voltage) swings is made significantly more difficult with the integration of additional intermittent generators into the system.

[71] Kirby & Milligan (2008), p.49.

[72] See NEMMCO (2001), p.6.

[73] SSD Rule Change, pp.53-55.

In order to manage the impacts on voltage of the connection of wind generators, it is typically necessary for the system operator to perform detailed studies to assess the impact of each new generator on the power system. In this context, the SSD Rule Change allowed NEMMCO to issue voltage control instructions to Semi-Scheduled Generators.[74]

Impact on network connection, planning and investment

The connection of renewable plant to the main transmission system is likely to have implications for network investment, both in relation to the need for certain assets at the immediate point of connection, as well as in relation to investment in core network augmentations.

At the connection point, the connection of significant quantities of renewable plant to an electricity network may give rise to operational issues or concerns about the security and integrity of the local network. Specifically, network operators may need to impose operational constraints and other technical requirements on renewable plant to maintain voltage control and fault recovery capabilities, which will tend to add to the plant's connection costs. For example, VENCorp's Connection Augmentation Guidelines provide that generators connecting to the grid are responsible for meeting the relevant access standard.[75] Further, in relation to wind farms specifically, VENCorp notes that there are occasions that warrant imposing additional obligations on wind farms by means of their connection agreements. This may include the requirement on a wind generator to install generation control equipment as a term of its connection to ensure that network limitations are not violated.[76]

Related to these connection costs, existing generation technical standards may be unnecessarily stringent for renewable plant. This could lead to higher costs for the development of renewable plant.[77]

In addition, the locations of new renewable plant may be diverse and remote from existing sources of conventional generation and the existing transmission network. Therefore, investment in the downstream transmission network may be required to allow the output of these plant to reach load centres. This raises the question of how such augmentations ought to be funded. It is unlikely that augmentations to facilitate the provision of power from new renewable plant would satisfy economic benefit criteria (such as the existing Regulatory Test in the NEM). Rather, investors in renewable plant may be required to pay for these augmentations as part of their connection agreements. If this were the case, the incidence of these costs would fall on retailers and ultimately end-use consumers.

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[74] SSD Rule Change, pp.56-57.

[75] VENCorp (2007), pp.18-19.

[76] VENCorp (2007), pp.30-31.

[77] See, for example, Gallaugher (2006), p.19.

Impact on retail market arrangements

As noted above, retailers and large users are required to acquire RECs under the expanded national RET scheme. To cover their resultant higher costs of supply, retailers will seek to recover these costs through higher retail tariffs. To the extent that regulated retail tariffs prevent appropriate cost pass through from retailers to end-use consumers, the financial viability of existing retailers and the incentives to enter the retail market may be adversely affected. This in turn may have implications for the vigour of retail electricity competition.

3.4.3 Impact on gas market structures and arrangements

In contrast to the CPRS, the expanded national RET scheme primarily affects Australia's electricity markets and, as such, has less direct consequences for gas market structures and arrangements. One indirect effect that the expanded national RET scheme may have on Australia's gas markets is to mitigate some of the effects of fuel shifting caused by the CPRS on domestic gas prices. This is due to the substitutability between shifting to gas-fired generation on the one hand and renewable generation on the other as potential abatement options. However, the extent to which this occurs is likely to be limited for two reasons:

- At this stage, renewable generation alternatives are not capable of providing baseload generation requirements, and hence fuel shifting from coal- to gas-fired generation for baseload needs will continue to occur irrespective of the expanded national RET scheme; and
- As discussed above, the incidence of gas price increases due to the CPRS is likely to be relatively small, and hence the potential for these effects to be offset by increased renewable generation may be fairly limited.

3.4.4 Summary

By creating a demand for RECs, the expanded national RET scheme will tend to increase the quantity of installed renewable generation capacity, such as wind. This will have major implications for electricity markets, in particular. Increased intermittent generation (such as wind) can create difficulties for system operators seeking to maintain system security in several ways. First, issues can arise when the output of wind plant cannot be controlled and the existing network is close to its limits. Second, issues can also arise when load is low and the output of conventional thermal plant needs to be reduced to allow for wind plant to run. This can result in conventional plant needing to be shut down and unable to restart in time to supply next-day load. The unpredictability of wind can also require that reserve plant margins be increased to ensure sufficient energy can be provided when required. Wind plant can also impose significant costs on the power system in terms of network augmentation and ancillary services (especially increased FCAS). Finally, the cost of RECs to energy retailers (both electricity and gas) need to be recovered from customers to ensure retailers are not squeezed and entry is not deterred. This is likely to require increases in regulated tariffs.

3.5 INTERACTION BETWEEN THE CPRS AND EXPANDED NATIONAL RET SCHEME

As noted above, the primary impact of the CPRS will be to increase the cost of emissions-intensive generation in Australia. In the longer term, the CPRS will provide pricing signals to encourage investment in renewable generation. The primary purpose of the expanded national RET scheme is thus to increase the supply of renewable generation in the short to medium term, during which time the CPRS is unlikely to encourage such investment. The transitional role that the expanded national RET scheme will play in Australia's long-term climate change strategy results in an interesting dynamic between this scheme and the CPRS.

As noted in section 3.4.1, the REC price received by renewable generation is a function of the average wholesale electricity price. Under the CPRS, wholesale prices will increase, due to the cost that carbon-emitting generators will incur through permit prices. This increase in wholesale prices will close the gap between renewable generators' LRMCs and average spot market prices. Hence, for a given quantity of renewable generation, REC prices will fall. REC prices will continue to fall as permit prices (and hence average wholesale prices) rise, until the point where the average wholesale price is equal to the LRMC of the marginal renewable plant. At this point, the expanded national RET scheme will be redundant since, for a given quantity of renewable generation, the CPRS will be providing the pricing signals necessary to encourage renewable generation investment.

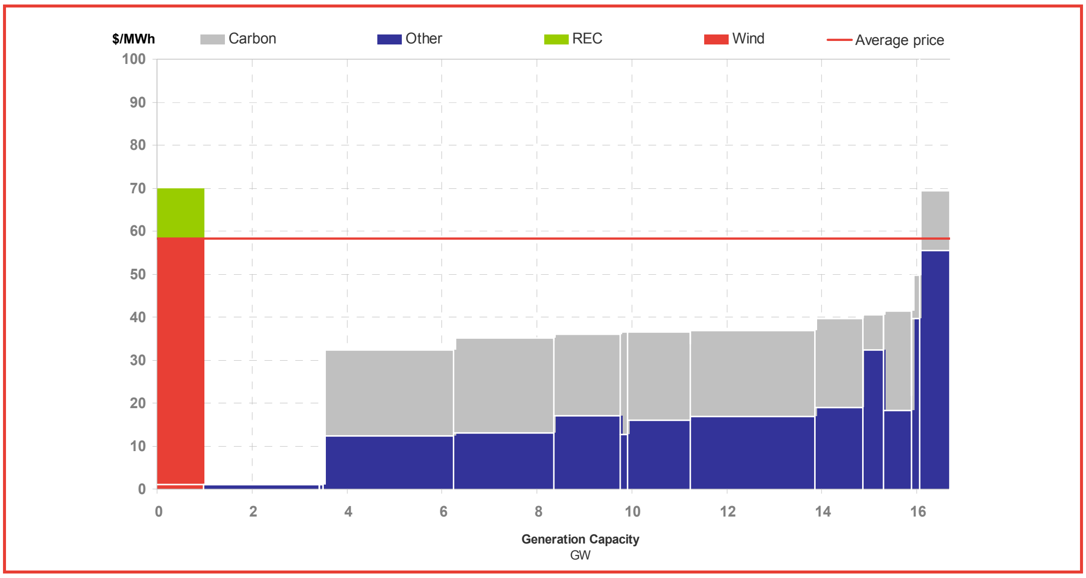

Figure 8: The impact of the CPRS on REC prices

Source: Frontier Economics

Falling REC prices due to higher wholesale energy prices post-CPRS introduction has been representatively modelled in Figure 8. As this example shows, the introduction of the CPRS, which imposes a cost of carbon on emitting generation, forces up the average wholesale spot price. In the example outlined in Figure 7 (where there was no CPRS), the average wholesale spot price was $36/MWh, while in this case the average spot price is $58/MWh. The $22/MWh increase is due to the CPRS.

As noted above, the price of RECs is defined as the difference between the average wholesale electricity price and the LRMC of renewable generation, which in this case is a wind plant with a LRMC of $70/MWh. To encourage this plant to enter the market, the REC price must equal the difference between the average wholesale spot price and this plant's LRMC, which is $12/MWh. This compares to a REC price of $34/MWh in the first (no CPRS) example. The $22/MWh reduction in the price of RECs is due to the corresponding $22/MWh increase in the average wholesale spot price, which is in turn was caused by the cost of carbon priced under the CPRS.

4 Jurisdiction-specific effects of climate change policies

4.1 INTRODUCTION

This section of the report builds on the summary of the Part I report in section 2 and the discussion of the generic effects of the CPRS and the expanded national RET scheme in section 3 to examine the following issues for both Western Australia and the Northern Territory:

- Direct and consequential effects of climate change policies on behaviour in the Western Australia and Northern Territory energy market frameworks;
- Risks that inefficient or unintended outcomes may occur due to the introduction of climate change policies and the changes in behaviour that could result;
- How the existing arrangements act to mitigate or exacerbate such risks; and
- Potential sub-optimal outcomes that may occur, and their materiality, given the existing arrangements.

As explained in section 1, we consider that all of these issues are inter-related and hence the response to each of them must emerge from the same analytical reasoning process. Therefore, instead of separating out these issues, we have examined them together.

However, prior to examining these questions, we consider it important to highlight an important exogenous fact that strongly influences the likely impact of the CPRS and expanded national RET scheme in Western Australia and the Northern Territory – the re-pricing of natural gas due to the scope for LNG exports.

4.2 INTERNATIONALISATION OF GAS PRICES

4.2.1 Background

Over the last few years, gas prices internationally have seen significant re-pricing due to gas's substitutability for oil, which has itself experienced dramatic price increases. Historical Japanese LNG import prices, OECD crude oil prices and Victorian wholesale spot market prices are shown in Figure 9.

An important difference between both Western Australia and Northern Territory's energy markets as compared to the southern and eastern states of Australia is that both Western Australia and Northern Territory have significant LNG export terminals, and hence sell natural gas on the world market. The southern and eastern states of Australia, by contrast, are largely isolated from international markets at this stage. In the longer term, this is likely to change due to the proposed LNG facility at Gladstone.[78]

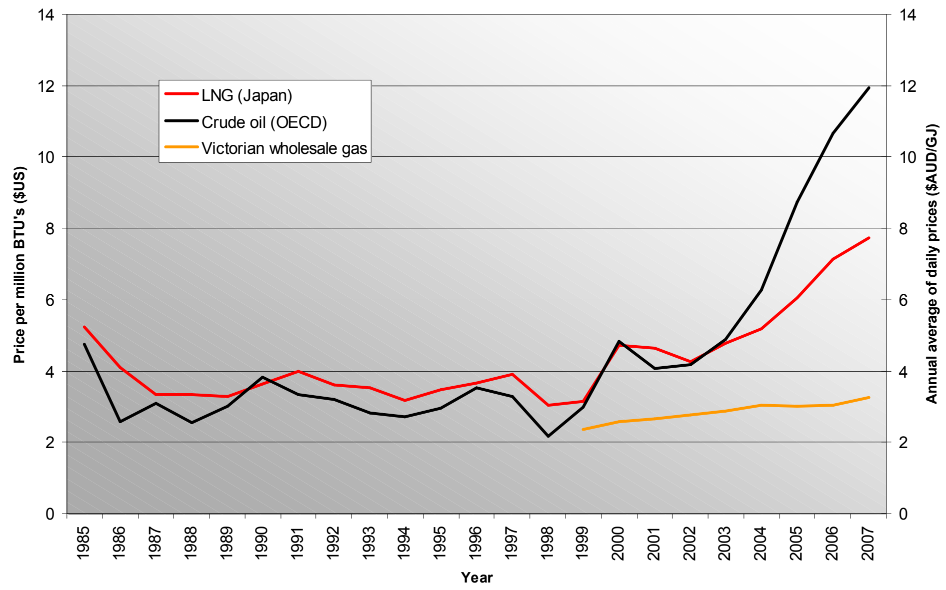

Figure 9: LNG, crude oil and Victorian wholesale gas prices, year-on-year

Data Sources: BP (2008), p.31 and VENCorp (http://www.vencorp.com.au)

4.2.2 Western Australia and Northern Territory LNG facilities

Western Australia's primary LNG facilities are situated in the Carnarvon Basin on the North West Shelf off Dampier. The North West Shelf Joint Venture is in the process of expanding its existing operation, with a fifth LNG production train due to be completed by 2008. In 2005/06 around 646PJ of gas produced from the basin was exported as LNG.[79]

The Northern Territory's primary LNG facility is situated onshore near Darwin, and is supplied with gas from the Bayu-Undan gas field in the Bonaparte basin. In 2006 the operator of the facility, ConocoPhillips, exported around 123PJ of gas produced in the basin as LNG.[80]

4.2.3 Consequences of internationalisation

The primary consequence of Western Australia and the Northern Territory exporting LNG is that they are exposed to international gas prices, while the southern and eastern states of Australia are not. Thus, while domestic conditions that affect demand and supply set the price for gas in southern and eastern

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78 http://www.lnglimited.com.au/IRM/content/project_australia.html

79 AER (2007), p.225.

80 AER (2007), p.225.

Australian states, international conditions set the price for un-contracted gas in Western Australia and the Northern Territory.

As Figure 9 suggests, LNG and crude oil prices track each other closely, due to their close substitutability for some purposes. The recent sharp increase in crude oil prices (until recently) has seen a corresponding increase in the price of imported Japanese LNG. Since major gas producers have the option of processing their gas as LNG and exporting it at international export prices, un-contracted gas in Western Australia and the Northern Territory has a lower-bound domestic price that is set by the prevailing international price for LNG.

The southern and eastern states of Australia, by contrast, are not exposed to international LNG prices. Domestic gas prices in these markets are set by local conditions (which historically has been moderate demand and available supply) and hence gas prices have remained relatively stable over time. This can be seen in Figure 9 by comparing the annual average daily spot market price for natural gas in Victoria to both the international price of crude oil and LNG.

While available price data for natural gas in Western Australia and the Northern Territory are not readily available (the majority of gas is sold under long-term confidential contracts), it is apparent that the gas market in both these jurisdictions has become increasingly tight, due in part to the large increase in the price of LNG. In its Gas Issues Discussion Paper[81] the ERA noted:

> Information from stakeholders indicates that gas prices in the Western Australian market have more than doubled in the 12 month period since early 2006 to a current level of around $5.50 to $6/GJ. This compares with $2 to $2.50/GJ in early 2006. By contrast, on the East Coast the availability of coal seam methane has driven gas prices down from around $3.50/GJ to about $3/GJ in Victoria and NSW and about $2.50 /GJ in Queensland.
>
> One of the stakeholders consulted estimated that the netback price of domestic gas, based on LNG prices at that time, was about $5.80/GJ. The netback price represents the price at which LNG producers would be getting a similar return on domestic gas and LNG taking into account the relevant infrastructure required to produce these two products. If LNG prices rise then the netback price would also rise. Over the long term, the ceiling price for domestic gas would be expected to be around the netback price level.

Recently listed offers to sell gas in Western Australia through the IMO's Daily Bulletin Board have been as high as $18.50/GJ.[82] We note, however, that this offer was placed during the height of the Varanus Island gas explosion, and hence does not represent a 'business-as-usual' scenario.

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[81] ERA (2007b), p.8.

[82] http://www.imowa.com.au/Attachments/GasBulletinBoard/downloadpdf.asp?fileid=GBB20080815.pdf

4.3 WESTERN AUSTRALIA

4.3.1 Impact of CPRS

Impact on gas-fired generation

As noted in section 3.3, a key effect of the CPRS will be to lessen demand for coal-fired generation and increase demand for gas-fired baseload power generation in Australia. This result is driven by the economics of the CPRS. The extent to which this occurs will depend on the cost 'spread' between coal- and gas-fired generation after CPRS introduction.

As discussed above, the price of contracted gas in Western Australia has more than doubled over the last few years, due in part to the large increase in the price of LNG. The NEM jurisdictions, by contrast, have been somewhat insulated from these international price effects, and as a result the price of gas in Western Australia is now far higher than in the NEM. This situation implies that, at least in the early stages of the CPRS when carbon prices are still relatively low, it is unlikely that fuel shifting from coal to gas will occur in Western Australia to the same degree as in the NEM.

This situation is expected to continue provided the carbon-inclusive SRMC of coal-fired generation in Western Australia remains below the carbon-inclusive SRMC of gas-fired generation. Once the latter becomes cheaper than the former (due to higher costs of securing carbon abatement in the NEM), one would expect to see fuel shifting in Western Australia.

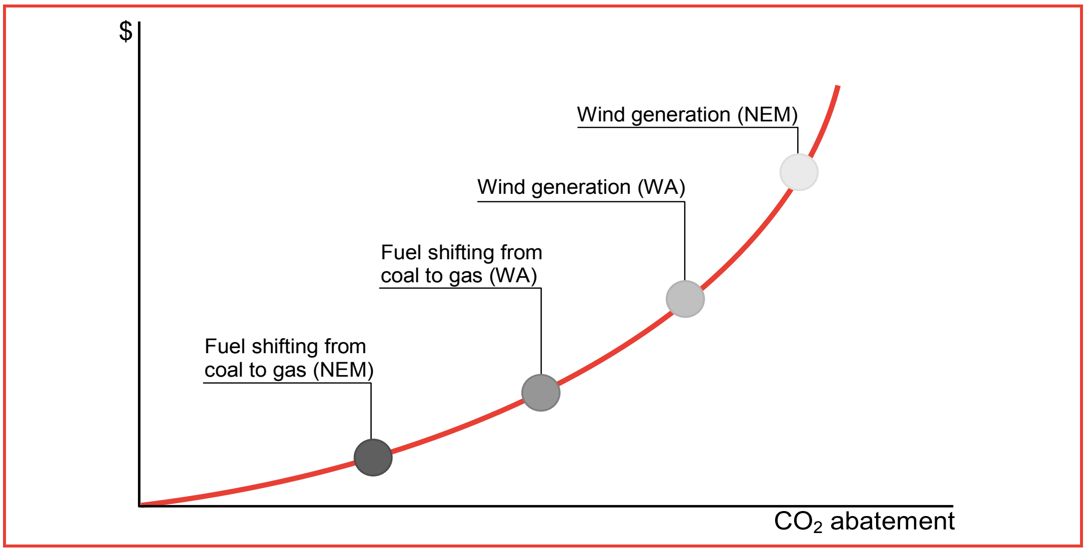

Figure 10: Abatement options under the CPRS

Source: Frontier Economics

This result is illustrated in Figure 10. This figure shows a simplified and stylised Marginal Abatement Cost (MAC) curve, which represents the cost of various abatement alternatives as a function of increasing quantities of abatement. Initially, the lowest-cost abatement option for Western Australian generators is likely for them to pay NEM generators to abate on their behalf through permit purchases. This is followed by Western Australian generators fuel shifting from coal to gas, and finally by various renewable options such as wind generation.

It is important to note that the inter-relationships between abatement options that underlie this MAC curve are dynamic and complex. Over time, the shape of this curve will change according to technological factors, the cost of generation inputs, permit prices and the extent to which investment in generation is required going forward. Thus, while fuel shifting from coal to gas is likely to be very expensive if plant are retired early (due to large sunk capital costs), fuel shifting at a time when new investment is required (due either to growing demand or scheduled plant retirement) is relatively much cheaper. In general, however, in the short to medium term, fuel shifting through required investment in new generation is likely to be cheaper in the NEM than in Western Australia, due to the smaller coal-gas cost spread in the NEM relative to Western Australia.

Impact on coal-fired generation

Due to the large coal-gas cost spread in Western Australia, it appears that at current gas prices, coal-fired generation under the CPRS is likely to be a cheaper option than gas-fired generation in Western Australia. It is for this reason that several coal-fired baseload generators have been and are being developed in Western Australia. Griffin Energy is currently constructing two sub-critical thermal coal-fired plants at Collie (Bluewaters I and II) with a combined capacity of 416MW, due for commissioning in late 2008/09.[83] In addition, Aviva is expecting to commence production of its 400MW coal-fired Coolimba Power Station in the State's mid-west region in 2009, for expected completion in 2012.[84]

It is illustrative to note that the Bluewaters I and II plant due to be commissioned mid-next year are 'sub-critical' plant. This represents relatively old technology compared to new generation super-critical designs. This use of (relatively) inefficient generation technology seemingly further illustrates the magnitude of cost spread between coal and gas in Western Australia – it appears that operational efficiency is of little importance given coal's overwhelming cost advantage over gas at the present time.

While coal-fired generation may prove to be least-cost in the early stages of the CPRS (prior to the ramping up of permit prices) the extent to which this remains the case going forward is uncertain.

Impact on renewable generation

In the long-term, the CPRS will encourage investment in zero- and low-emission generation technology. While the expanded national RET scheme will drive much of this investment in the short to medium term (as discussed in section 4.3.2), there are long-term implications of the CPRS for zero- and low-emission generation in Western Australia. At the present time, the most mature and viable zero-emission technology is wind, with solar, geothermal and tidal technologies

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83 See http://www.griffinenergy.com.au/default.aspx?MenuID=76.

84 See http://www.avivacorp.com.au/default.aspx?id=201.

only likely to mature in the longer term. Given that Western Australia has a high proportion of productive[85] wind sites relative to other areas of the country, the average LRMC of wind generation in Western Australia is likely to be lower than in other states, thus making wind generation in Western Australia a cheaper abatement option on average than in the NEM. This is shown on the stylised MAC curve in Figure 10. The lower LRMC of wind generation, in combination with higher wholesale energy prices due to the CPRS, will likely see Western Australia moving to greater wind generation earlier than the NEM. In the absence of the expanded national RET scheme, this transition will begin once average wholesale electricity prices in Western Australia exceed the LRMC of wind generation, as explained in section 3.5.

Energy security

As noted in section 3.3.1, a generic effect of the CPRS in the short to medium term will be to encourage fuel shifting from coal- to gas-fired generation. This increased reliance on gas for electricity generation needs has potential implications for energy security. However, the extent of fuel shifting in Western Australia as a result of the CPRS is likely to be limited, due to the high exogenously-set cost of gas in Western Australia relative to the NEM. While Western Australia is presently strongly reliant on gas-fired generation (as was recently demonstrated during the Varanus Island disruptions) with roughly 52%[86] of total installed capacity being gas-fired in the SWIS, this reliance is not expected to increase in the short to medium term. If and when gas becomes similarly re-priced in the NEM, this may change as the relatively cheap abatement option of fuel-switching in the NEM dissipates. In the longer term, as pricing signals emanating from the CPRS encourage increased renewable generation investment in Western Australia, it is expected that Western Australia's generation mix will become more diversified, and hence their reliance on gas-fired generation is likely to decrease.

Impact on retail market arrangements

As discussed in section 3.3.1 above, to the extent that the CPRS results in increased wholesale electricity prices, retail market arrangements may need to be reviewed to allow retailers to pass through such cost increases to end-use customers. This issue is particularly important in Western Australia, given that retail prices are already well below cost-reflective levels.

As noted by the Office of Energy in its Retail Market Review draft recommendations[87], regulated retail tariffs in Western Australia prior to this year[88] had not escalated since 1997/98, reflecting a real price reduction to 2009/10 of

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[85] Wind sites with high capacity factors.

[86] http://www.energy.wa.gov.au/cproot/1268/11070/Generation%20capacity%2005082008.pdf

[87] OOE (2008).

[88] To date three tariffs (R, S and T) have increased. These tariffs relate only to large customers who are mostly above the contestability threshold, and who represent less than 1% of total retail customers.

approximately 30%. To return retail tariffs to cost-reflective levels, the Office of Energy recommended that residential tariffs should increase by 47 per cent in 2009/10, and tariffs for other small use customers should increase by between 21 per cent and 44 per cent. The former Government instead affirmed that there would be a 10 per cent increase in tariffs from 2009/10 with further annual increases to be phased in over a six to eight year period. The new government's position on the cost-reflectivity of retail tariffs is as yet unclear.

In its draft recommendations, the Office of Energy recommended that residential tariffs should increase by 15 per cent in 2010/11, with the bulk of this increase (11 per cent) being driven by the expected impact on wholesale electricity prices of the CPRS. This increase was based on an assumed carbon price of $26.36/tonne in 2010/11[89]. This price estimate is above that recommended during the transitory period 2010-2012 in the Garnaut Report of $20/tonne +CPI.

To the extent that regulated tariffs remain non cost-reflective in Western Australia, the introduction of the CPRS is likely to exacerbate the existing issues currently facing the market. In light of this, a review of regulated retail prices may be justified to ensure appropriate cost pass through from retailers to end-use customers is facilitated.

Impact on gas market arrangements

Western Australia's primary gas pipeline, the Dampier to Bunbury Natural Gas Pipeline (DBNGP), runs from Dampier to Perth and then on to Bunbury, supplying gas from the Carnarvon basin to users in the State's populated southwest. Access to the DBNGP is regulated under the *National Gas Code* by the ERA. The DBNGP has undergone significant expansions over the last few years, including:

- Stage 4 expansions – a $430m upgrade involving 8 new compressors and over 200km of looping, completed in 2004; and
- Stage 5A expansions – a $660m upgrade involving 10 loops with a total length of 570km, completed in early 2008.

Phase 5B expansions, involving a further 440 km of looping and compressor station modifications at a cost of $690 million, are due to commence in early 2009 and be completed during the second half of 2010. Despite these recent capacity expansions, it has been reported that securing access to capacity on the DBNGP is becoming increasingly difficult.

The DBNGP plays an important role in both Western Australia's electricity and gas markets, since a large portion of the State's southwest gas-fired generators source their gas from the Carnarvon basin via the DBNGP. In its 2008 annual market report Discussion Paper[90], the ERA highlighted the disconnect between the respective timings of pipeline nominations on the DBNGP and STEM

[89] OOE (2008), p.15.

[90] ERA (2008a).

submissions in the WEM. Those participants that source gas from the DBNGP for generation in the WEM and who wish to participate in the STEM must make STEM submissions on the Scheduling Day, being the day before the Trading Day. However, participants only receive confirmation of the availability of spot gas and transport on the DBNGP later in the Scheduling Day. These participants must thus make STEM submissions based on estimates of gas availability for the following day, due to the timing difference between STEM submissions and the operational procedures on the DBNGP. Participants that do not receive their expected quantities of gas may be required to operate on liquid fuel, having submitted STEM bids and offers on the assumption they would operate on gas. This situation can have implications for the financial positions of these market participants. The ERA raised various options for addressing this disconnect, such as moving the STEM closer to real time and introducing multiple gate closures.

The extent to which this issue is exacerbated by the CPRS will depend on the extent to which this policy increases the demand for natural gas as an input into electricity generation in Western Australia. As noted above, in the short to medium term, it is unlikely that a great deal of fuel shifting from coal to gas will occur in Western Australia, due to the large coal-gas cost spread in the State. As and when fuel shifting does occur in Western Australia, the risks participants face due to mis-timing between the DBNGP and STEM operational procedures may increase. We also note that the new Government has announced its intensions to extend the DBNGP from Bunbury to Albany.[91] To the extent this increases demand for gas from the DBNGP, this extension is also likely to increase the risks currently faced by the relevant market participants.

Options to address the current timing imbalance between STEM Submissions and operational procedures on the pipeline include moving the STEM closer to real-time, introducing multiple STEM gate closures, or revising the operational producers on the DBNGP.

4.3.2 Impact of the expanded national RET scheme

Impact on the growth of renewable generation

At present, there is less than 200 MW of wind generation connected to the SWIS.[92] Although we have not performed independent modelling, we understand from stakeholder discussions that the expanded national RET scheme has contributed to a potential pipeline of well in excess of 1 GW of new wind projects in the State. Not all of this may go ahead, but if even a relatively small proportion of the new projects proceed, it is likely to create issues for system management. Wind power is considered by most stakeholders to be the only scaleable renewable resource available in Western Australia that can respond to the incentives created by the expanded national RET scheme at this time.

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91 http://www.mediastatements.wa.gov.au/Pages/CourtCoalitionGovernmentSearch.aspx?ItemId=11314 6&minister=Court&admin=Court

92 See IMO website at: http://www.imowa.com.au/PUB_RulePartFacilityInfo.htm

An increase in wind generation due to the expanded national RET scheme has the potential to profoundly impact the WEM, due to the small size of the market and the sheer number and quantity of wind projects that are expected to connect to the SWIS pursuant to this policy. Issues associated with a substantial increase in wind generation are likely to arise in the following areas:

- Dispatch of scheduled generators;
- Verve Energy exposure to balancing;
- Reserve Capacity Mechanism;
- Transmission connection delays and overbuilding; and
- Ancillary services costs.

These issues are discussed below. We understand that many of them are being considered by the Renewable Energy Working Group (REWG), which was set up in March 2008 under the auspices of the Market Advisory Committee.[93] The REWG was formed to consider and assess system and market issues arising from the increase in the MRET to 45,000 GWh by 2020.

In particular, the REWG will focus on:

- Capacity Credits allocated to intermittent generators through the Reserve Capacity Mechanism;
- Implications for the need for ancillary services; and
- System security at times of low load.

The REWG's first meeting was held on 3rd April 2008 and the second meeting was on 22 May 2008. However, to date, the REWG has not published any recommendations.

Impact on the dispatch of scheduled generators

A key concern relating to increasing wind generation in Western Australia is the effect it could have on the dispatch on conventional generation – especially coal-fired plant – at low-load times such as overnight. This is one of the issues currently before the REWG.

Overnight load in the SWIS is only about 1,000 MW, and Western Australia is not interconnected with other systems to enable the export of surplus power. At the same time, renewable generation such as wind is unscheduled and tends to be highly variable and unpredictable. Further, due to the fact that RECs have a positive price, it is likely that wind farms would in any case be willing to run overnight and 'spill' into balancing at a negative price (noting that intermittent generation receives (or pays) MCAP if it generates more than its Net Contract Position).[94]

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93 See IMO website at: http://www.imowa.com.au/mac_workinggroups.htm

94 IMO, p.55.

The spilling of wind generation into balancing has potential implications for thermal generation plant, who may need to be backed off towards minimum stable generation levels overnight and possibly need to shut down. While investment in any generation technology could lead to a situation of excess supply at off-peak times and the need for shut downs, the sheer variability of wind generation creates additional issues: Even where overnight load is high enough to sustain coal-fired plant operated above minimum stable levels *on average*, the variability of wind may lead to System Management deciding to turn down or shut down coal-fired generation units and start up more flexible gas turbines, in order to compensate for the volatility of output from wind plant.

Turning down coal-fired generators to the point where they need to shut down overnight is undesirable for several reasons:

- Coal-fired plant are typically designed to run in a baseload manner – it is unlikely to be technically feasible to shut down these plant on a daily basis. This issue is exacerbated in the SWIS given Western Australia's aging coal-fired generation portfolio – comprising plant such as Muja, Pinjar, Collie, as well as some co-generation plant that would prefer not to shutdown overnight; and
- Even if coal-fired plant can be shut down overnight, there are lags involved in bringing them back to full service the next day. Consequently, shutting down such plant may have implications for next-day system security and reliability if next-day demand is high enough to require those plant back in service at full capability. This can be an issue in both summer and winter in the SWIS:
  - In summer, peak system load (which is generally at its highest) is reached in the mid to late afternoon, leaving System Management less than 12 hours to potentially restart coal-fired units;
  - In winter, peak system load is lower than in summer, but can be reached in early morning as households start heaters and utilise hot water. This potentially gives System Management very little time to restart (fewer) units that were shut down over night.

Under Chapters 3 and 7 of the WEM Rules, System Management has discretion to intervene in wind power dispatch to manage dispatch while maintaining power system security and reliability. If wind is backed off by System Management in balancing, the plant is paid for its foregone output based on its pay-as-bid price,[95] unless it is party to an automatic run-back scheme. Based on our discussions with Western Power staff, decisions to turn down a particular unit are based on merit order bids, subject to system security considerations. If System Management considers that security would be jeopardised by turning down conventional generation, it will focus on reducing wind output.

However, this puts System Management in the unorthodox and invidious position of interpreting and forecasting system security on a day-ahead basis in

[95] IMO, p.55.

order to determine whether it ought to back-off wind or conventional generation at low load times. It is worth emphasising that this problem arises due to a combination of low overnight load and the variability of wind generation rather than binding network limits. Hence, it would not be addressed by the direct equivalent of the Semi-Scheduled Dispatch Rule Change in the NEM. However, a similar approach could be used to facilitate the more transparent turning down of wind plant dispatch where failing to do so could require conventional plant to shut down.

These emerging problems identify a need for a more transparent process governing how System Management intervenes in merit order dispatch to turn down both wind and conventional generation for system security reasons.

Impact on balancing

As noted above, Verve Energy has the primary responsibility of balancing in the WEM. This means that Verve Energy:

- Will *be paid* MCAP if it is required to supply increased demand in balancing; and
- Will have *to pay* MCAP if it is required to purchase increased supply in balancing.[96]

While the calculation of MCAP has been recently modified,[97] it still does not compensate Verve Energy for situations where System Management decides to shut down inflexible coal-fired plant and start flexible gas turbines overnight to cope with the variability of wind generation at those times.

Other scheduled generators in the WEM are settled for their:

- Excess output by receiving (the relatively low) UDAP; and
- Insufficient output by paying (the relatively high) DDAP.[98]

By contrast, non-scheduled (e.g. wind) generation is the only type of generation that can spill into balancing and be paid for the energy it produces – intermittent plant receive MCAP for any energy they produce in excess of their Net Contract Position.[99] Verve Energy is then required to effectively pay MCAP for the output of these plant. This may be significantly more than the cost to Verve Energy of generating more power itself. Hence, it is quite possible that these arrangements could lead to inefficient dispatch. The emergence of more wind plant in the WEM is likely to further increase Verve Energy's exposure to balancing and potentially further harm efficiency.

The WEM could move to 'competitive balancing' to overcome this problem. This refers to a balancing design in which Verve Energy would be treated like any

96 IMO, p.55.

97 IMO (2008).

98 IMO, p.55.

99 IMO, p.55.

other generator – any re-scheduling of its output upwards or downwards would be settled on the basis of its pay-as-bid price. The ERA has raised this option on several occasions.[100] However, competitive balancing would have significant implications for the cost of balancing in light of Verve Energy's undisputed market power. For this reason, to date, there has been little enthusiasm for moving to competitive balancing in the absence of further structural reforms on the generation side of the market. As an alternative to moving to competitive balancing, these potential inefficiencies could also be addressed to some degree through better control over the dispatch of wind generation (discussed above) and more cost-reflective recovery of load-following costs (discussed below).

Impact on the Reserve Capacity Mechanism

As noted in section 2.1.1, reserve capacity in Western Australia is based on ensuring that forecast peak demand can be met in nine years out of 10, after the outage of the largest generation unit in the SWIS, while allowing for some residual frequency management capability.

Under the WEM Rules, existing intermittent generators are entitled to Capacity Credits based on their average sent-out generation over the preceding three years.[101] For new intermittent generators, the amount of credits is based on an expert's opinion of what the generator's sent-out energy would have been, had the unit been in operation over that period.[102] Anecdotally, it appears that wind plant receive Capacity Credits equivalent to approximately 40% of their rated capacity.[103] However, there is no guarantee that this proportion of the plant's output will actually be generated at times of peak demand. Therefore, the Reserve Capacity Mechanism may reward renewable plant with Capacity Credits even when they do not generate that amount at times of peak load. Therefore, as wind generation penetration increases as a result of the expanded national RET scheme, these arrangements may expose the SWIS to an increasing risk of supply shortfalls due to a lack of real-time available generation.

We understand that the Office of Energy is presently considering alternative methods of accrediting wind plant capacity. To be effective in time for the assignment of Capacity Credits for the 2011/12 capacity year, any revision to the existing approach would need to be implemented by May 2009. There would be benefits to changing the Capacity Credit accreditation methodology so that it recognised the true availability of various plant, including wind. In this context, we note that in Western Power's submission to the ERA on its 330 kV line proposal, consultants CRAI assumed a similar contribution to peak summer

100 See ERA (2008a), pp.26-27.

101 Rule 4.11.1(d) and 4.11.3A

102 Rule 4.11.1(e).

103 For example, the 80 MW Emu Downs Wind Farm received 31.105 MW of Capacity Credits for 2010/11 (equivalent to 38.9% of their rated capacity). See the IMO website at: http://www.imowa.com.au/Attachments/RC_Attachments/SummaryofCapacityCreditsfor2008ReserveCapacityCycle.pdf.

capacity from the Walkaway Wind Farm as had been applied in South Australia. Therefore, only 5 MW was included out of a 90 MW rated capacity.[104]

Our discussions with the IMO also highlighted the need to integrate the Reserve Capacity Mechanism with transmission, to recognise the differing value of capacity in different locations within a constrained SWIN. In light of this, consideration of establishing regional or locational reserve capacity requirements and Capacity Credits may be warranted going forward. We note that the new Reliability Pricing Mechanism in the Pennsylvania-New Jersey-Maryland (PJM) market in the United States seeks to provide locational signals for capacity.[105]

Impact on transmission connection delays and network overbuilding

An important implication of the expanded national RET scheme that is also related to the Reserve Capacity Mechanism is the length of the delays involved in securing a network connection. As noted in section 2.1.1 above, due in part to the 'unconstrained' network policy in place in Western Australia, connecting parties face long delays – potentially over two year – in receiving a network access offer. There may then be further delays in actually getting connected to the network.

The expanded national RET scheme has meant a substantial increase in the number and volume (in MW capacity) of new wind projects seeking connection to the SWIN, particularly in light of the ERA's approval of the 330 kV transmission line in the mid-west region.[106] This has added to the length of the 'queue' for network access offers. Further, Western Power assesses applications in the order in which they are submitted, and does not prioritise based on plant technology or size. We understand that many wind generators are towards the front of the queue. This has all added to the present delays for new connections.

The interaction between new connections and the Reserve Capacity Mechanism arises because new generators are only entitled to be assigned Capacity Credits if they have received a network access offer.[107] However, as noted in section 2.1.1, the wait for new generation proponents to receive a network access offer can be over two years.

Furthermore, even when a prospective generator proponent receives a network access offer, it is liable to make reserve capacity refunds if its plant is not actually connected by the time it is required to provide capacity.[108] At present, Western Power bears no accountability for delays in the timing of new connections. The ERA has raised the prospect of implementing a mechanism to provide stronger

[104] CRAI (2007), p.7.

[105] See Chandley (2008), pp.3-4.

[106] See ERA (2007c).

[107] Rule 4.10.1.

[108] ERA (2008a), p.19.

incentives for delivery of network connections on a timetable that is appropriate to the Reserve Capacity Mechanism.[109]

As well as causing delays to the connection process, there is little doubt that the unconstrained planning approach leads to inefficient over-investment in the transmission network. After all, in some cases it may be more efficient to allow some congestion to occur than to augment the network. However, correspondence from Western Power staff has raised the difficulties of moving to a constrained planning approach. In particular, such a shift would require:

- Development, management and implementation of constraint equations by System Management; and
- Review of the role and functioning of the Reserve Capacity Mechanism, as the IMO could not be confident that all capacity that is accredited would be able to meet load at peak times.

Nevertheless, in the context of long delays to network access offers brought about by the expanded national RET scheme, a comprehensive review of the unconstrained planning approach appears justified. The ERA has raised for comment the potential usefulness of a long-term 'roadmap' for market development to examine issues such as this.[110]

Impact on ancillary services costs

As noted in section 3.4.2, an increase in intermittent generation due to the expanded national RET scheme could lead to an increased need for frequency control ancillary services – specifically, regulation reserve or load-following.

Our understanding is that the required amount of load-following reserve in Western Australia has increased from about 30MW to 60MW, and is expected to rise further as more wind plant are connected to the SWIS. Further, the costs of these ancillary services are recovered on a *pro rata* basis from load and non-scheduled generation.[111] Nevertheless, based on discussions with stakeholders, the widespread view is that wind plant do not pay for the additional ancillary services costs they impose on the system. This is because the output of wind plant can be more variable and unpredictable than customer load.

Consequently, a review of the charging regime for load-following, to ensure that wind plant are held financially accountable for the costs they impose on the power system, appears justified. We understand that the REWG is specifically considering this issue. In addition, some stakeholders have also suggested that wind plant do not pay for the costs of network voltage control ancillary services they impose. Therefore, any potential review of ancillary service cost allocation may also need to consider whether wind plant are presently appropriately accountable for any additional network and/or voltage control ancillary services their connections require.

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[109] ERA (2008a), p.19.

[110] ERA (2008a), pp.31-32.

[111] IMO (2006), p.23.

Impact on retail market arrangements

As noted in 3.4 above, the most direct effect of the expanded national RET scheme is to expand the demand for RECs. This will tend to increase the quantity of renewable generation capacity. Retailers will seek to recover the costs of acquiring RECs through higher retail tariffs. However, as was explained in section 4.3.1 in relation to the CPRS, it is not clear that Synergy, at least, will be able to do this in Western Australia due to the non-cost reflective regulated retail tariffs currently in place. To the extent regulatory arrangements prevent competitive retailers from recovering the cost of RECs, this is likely to make retail entry in Western Australia even less attractive than it is currently. This may have adverse implications for the strength of retail electricity competition. In light of this, a review of retail market arrangements to ensure appropriate cost pass through from retailers to end-use customers is facilitated may be required.

4.4 NORTHERN TERRITORY

4.4.1 Impact of CPRS

Impact on baseload generation

As noted in section 2.2.1, over 99% of energy in the Northern Territory's regulated systems is generated using gas-fired plant. This strong reliance on gas-fired generation, coupled with a lack of viable low-emission alternatives (further discussed below), implies that the Northern Territory is likely to be particularity exposed to increased wholesale generation costs as the cost of carbon ramps up. In contrast to Western Australia, Northern Territory has virtually no coal deposits or viable renewable alternatives, and hence must continue to meet its generation needs virtually exclusively from gas-fired plant in the short to medium term.

As was the case with Western Australia, the Northern Territory's domestic gas market is highly exposed to international LNG prices, and as such has experienced similar gas price pressures to Western Australia in recent years. The lack of low-cost abatement options will likely result in limited carbon abatement in the Territory, with Territory consumers effectively paying NEM generators to abate on their behalf in the early stages of the CPRS, through the purchase of carbon permits. In the absence of viable renewable alternatives going forward, the Northern Territory is likely to experience significant increases in wholesale electricity generation costs as permit prices increase in the medium to long term, due to its sole reliance on natural gas for its generation needs. While not directly related to the CPRS *per se*, the Territory's electricity industry is likely to continue to be highly exposed to international LNG prices due to this lack of fuel diversification.

Impact on renewable generation

As a generic impact, the CPRS will encourage investment in renewable generation alternatives in the long-run. While the Northern Territory has virtually no suitable wind sites, geothermal, tidal and solar (photovoltaic and thermal) are all renewable technologies suitable for the Territory that may become viable as carbon prices increase and these technologies mature going forward.

Energy security

Unlike Western Australia, the Northern Territory is virtually solely reliant on gas-fired plant for its generation needs, with roughly 99% of generation in the Territory being gas-fired. As noted above, due to its lack of coal deposits or viable renewable alternatives, the Territory must continue to meet its generation needs virtually exclusively from gas-fired plant in the short to medium term. In the longer term, once pricing signals emanating from the CPRS begin to encourage investment in renewable generation (such as solar or geothermal), the Northern Territory's fuel diversification may begin to increase, and hence their reliance on gas-fired generation is likely to subside.

Impact on retail market arrangements

As was the case with Western Australia, the Northern Territory's retail market arrangements may need to be reviewed due to higher wholesale energy costs under the CPRS going forward. In particular, retail price caps currently in place in the Northern Territory may require revision to ensure the adequate pass-through of CPRS costs from retailers to end-use customers to maintain the viability of retailing.

4.4.2 Impact of the expanded national RET scheme

Due to its climatic characteristics, the Northern Territory is less suitable for viable (relatively low cost) renewable technologies such as wind and biofuels that are common to other regions of Australia. To date, the Territory has managed to meet its RET obligations primarily through the creation (and surrender) of RECs from solar hot water, solar power generation and landfill gas generation schemes. It is unlikely, however, that retailers in the Northern Territory will be in a position to develop sufficient renewable options themselves to meet their obligations under the expanded national RET scheme going forward.[112]

The inability of Territory retailers to meet their the expanded national RET scheme obligations locally will require them to purchase RECs from other jurisdictions with more available supplies of renewable generation. The Northern Territory is thus likely to be relatively exposed to the price of RECs under the expanded national RET scheme. As discussed in section 3.5, there is close interaction between the CPRS and expanded national RET scheme. The primary result of this interaction is that rising permit prices under the CPRS will force up wholesale electricity prices, which in turn will force down REC prices, since a lower subsidy will be required to incentivise a given level of investment in renewable generation. To the extent that REC prices fall over the course of the expanded national RET scheme, the Northern Territory's exposure to such

[112] PWC (2007), p.21.

prices due to its lack of local renewable generation options will be somewhat mitigated.

As was the case with Western Australia, the requirement under the expanded national RET scheme for retailers to acquire RECs will increase the cost of supplying electricity. Retailers will seek to recover the costs of acquiring RECs through higher retail tariffs. To the extent regulatory arrangements prevent competitive retailers from recovering the cost of RECs, entry into the Northern Territory retail market may be deterred. A review of retail price arrangements may be required to ensure the viability of retailers, and to prevent the erosion of competition in retail electricity.

5 Conclusions

The Government's two primary climate change policies going forward are the CPRS and the expanded national RET scheme. While both of these policies have numerous generic effects on energy markets, characteristics specific to the Western Australian and Northern Territory energy markets imply that these policies will have certain unique effects on these markets.

Impacts on Western Australia's energy markets

The CPRS will, as in other jurisdictions, increase the wholesale cost of electricity and gas in Western Australia, as producers seek to pass through the costs of permits. Ordinarily, this could be expected to lead to fuel-shifting from high- to low-emissions intensive sources of energy, such as from coal-fired electricity generation to gas-fired generation. However, due to the internationalisation of gas prices in Western Australia, it is unlikely that fuel shifting from coal to gas will occur to the same degree as in the NEM states. This result is driven by the high coal-gas cost spread in Western Australia, which in turn is driven by the high price of natural gas as a result of the scope for LNG exports. At least in the early stages of the CPRS, coal-fired generation may prove to be more cost-effective than gas-fired generation at current gas prices. The extent to which this remains the case as permit prices ramp up over time is uncertain. Nevertheless, to the extent that fuel-shifting is limited in Western Australia, the energy security issues that could otherwise be expected to follow from the impact of the CPRS in encouraging gas-fired generation are likely to be mitigated.

In the short to medium term the expanded national RET scheme will incentivise increased investment in renewable generation, particularly in wind plant. In the longer term, pricing signals emanating from the CPRS will continue this trend. Due to the high quality of wind sites in Western Australia, combined with the high price of gas, it is expected that a move to substantial investment in wind generation will occur in Western Australia before such investment occurs in the eastern states. However, increased quantities of wind generation are creating a number of difficult issues for the Western Australian electricity market. Most of these issues are driven by the intermittent and unpredictable nature of wind generation. For example, the variability of wind generation means that conventional coal-fired plant may need to be shut down at low-load times, potentially leading to insufficient available generation if the plant is needed again soon afterwards (such as winter mornings). The variability of wind also means that it is not as reliable a source of reserve as thermal plant, potentially necessitating an increase in the required reserve plant margin. Wind generation variability has also led to an increased requirement for load-following ancillary services, and it does not appear that wind generators are currently paying for an appropriate share of these costs. Increasing wind generation has also, combined with the current 'unconstrained' network planning approach, led to long delays for new generators seeking to be connected.

Both CPRS and expanded national RET are likely to lead to higher retail costs to serve for both electricity and gas. These effects may need to be reflected in regulated retail tariffs to help ensure that retailing remains a viable activity and that entry into retail markets is not deterred.

Impacts on the Northern Territory's energy markets

As in the case of Western Australia and elsewhere, the CPRS will increase wholesale electricity and gas costs and prices. However, as with Western Australia, the domestic price of gas in the Northern Territory is considerably higher than in the southern and eastern states of Australia due the internationalisation of prices through LNG exports. Because of its sole reliance on gas-fired generation for its electricity needs, fuel shifting is not a realistic option in the Territory. As permit prices increase under the CPRS, the Northern Territory is likely to experience significant increases in the price of wholesale electricity. This is due to a lack of viable generation alternatives. Therefore, the CPRS is likely to only heighten existing energy security issues in the Northern Territory raised by its reliance on gas as a fuel for electricity generation.

Due to a lack of viable renewable generation options at the current time, the Northern Territory is unlikely to be able to meet its obligations under the expanded national RET scheme by producing RECs locally. As such, the Territory will likely need to purchase RECs from other jurisdictions with more abundant renewable generation sources. Since rising permit prices will force down the price of RECs for a given RET target going forward, the extent of REC price exposure that the Northern Territory faces is likely to be partially mitigated. As with Western Australia, retail energy prices in the Northern Territory may need to be adjusted to reflect higher costs to serve, to ensure that retailing remains a viable activity and that entry into retail markets is not deterred.

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Appendix A: A review of the Western Australia and Northern Territory Energy Markets

A PRELIMINARY REPORT PREPARED FOR THE AUSTRALIA ENERGY MARKET COMMISSION

October 2008

Appendix A: Part I report

A review of the Western Australia and Northern Territory Energy Markets

Tables, figures and examples

Tables:

Figures:

1 Introduction

This report has been prepared by Frontier Economics (Frontier) for the Australian Energy Market Commission (the Commission) to provide an overview and summary of the existing gas and electricity market structures and supporting energy market frameworks in Western Australia and the Northern Territory.

This report is the first deliverable in a wider consultancy that examines the implications for the Western Australia and Northern Territory energy markets from climate change policies, namely the Carbon Pollution Reduction Scheme (CPRS) and expanded national Renewable Energy Target (RET) scheme.

Given the size and sophistication of Western Australia's energy markets relative to those of the Northern Territory, the focus of this report is on Western Australia's energy markets. Within that topic, this review focuses on the heart of Western Australia's energy markets, the Wholesale Electricity Market (WEM). The WEM operates across the South West Interconnected System (the SWIS). The discussion of Western Australia's other interconnected system, the North West Interconnected System (NWIS) and its various non-interconnected systems, is relatively limited. Likewise, the discussion of the Northern Territory's energy market arrangements is relatively brief.

This report is structured as follows:

- Section 2 describes Western Australia's electricity and gas market arrangements, at both wholesale and retail levels. This section concludes with a brief recitation of the main issues within Western Australia's energy markets that will require consideration in Frontier's later report; and
- Section 2.2 describes the Northern Territory's electricity and gas market arrangements, also at both wholesale and retail levels. This section also concludes with a brief recitation of the main issues within the Northern Territory's energy markets that will require consideration in Frontier's later report.

A complete collection of references used in undertaking this review can be found at the end of this report. A numerical example, referred to in section 2.1.2, can be found in Appendix B.

2 Western Australia

2.1 ELECTRICITY

2.1.1 Institutional and governance arrangements

Introduction

Western Australia's electricity supply industry is comprised of several distinct systems – the South West Interconnected System (the SWIS), the North West Interconnected System (the NWIS), and 29 regional, non-interconnected power systems.[113] Western Australia's primary electricity infrastructure is illustrated in Figure 1. No part of Western Australia's electricity networks interconnect with the National Electricity Market (NEM).

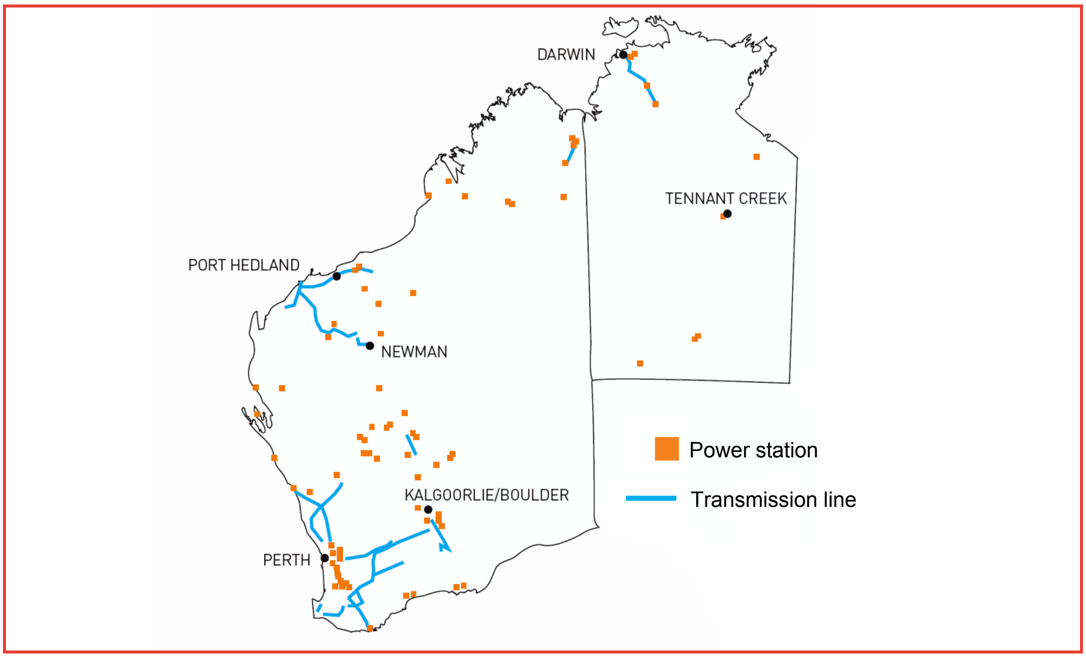

Figure 11: Western Australia and Northern Territory electricity infrastructure

Source: AER (2007), p.64.

The SWIS is the major interconnected electricity network in Western Australia, supplying the bulk of the south-west region. It extends to Kalbarri in the north, Albany in the south, and Kalgoorlie in the east. The network supplies 840,000 retail customers with 6,000 km of transmission lines and 64,000 km of distribution lines. As of August 2008 the SWIS had installed capacity of 5,134 MW – this included 240 MW of capacity that is due to be retired by the end of 2008.[114] Western Australia introduced the Wholesale Electricity Market (WEM) into the SWIS in September 2006.

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113 AER (2007), p.204.

114 http://www.energy.wa.gov.au/cproot/1268/11070/Generation%20capacity%2005082008.pdf

The NWIS operates in the north-west of the state and centres around the industrial towns of Karratha, Port Hedland, and other major resource centres. The NWIS has a generation capacity of 400 MW and transmission, distribution and retailing functions are performed by Horizon Power. Horizon Power purchases power from private generators, including Hamersley Iron's 120MW generation plant at Dampier, Robe River's 105 MW plant at Cape Lambert and Alinta's 105 MW plant at Port Hedland. Due to the small scale of this system, the NWIS will not see the introduction of a wholesale market in the foreseeable future.

Numerous small, non-interconnected distribution systems operate around towns in rural and remote areas beyond the SWIS and NWIS networks. Horizon Power operates the 29 distribution systems located in these regions, but independent generators supply much of the electricity.[115]

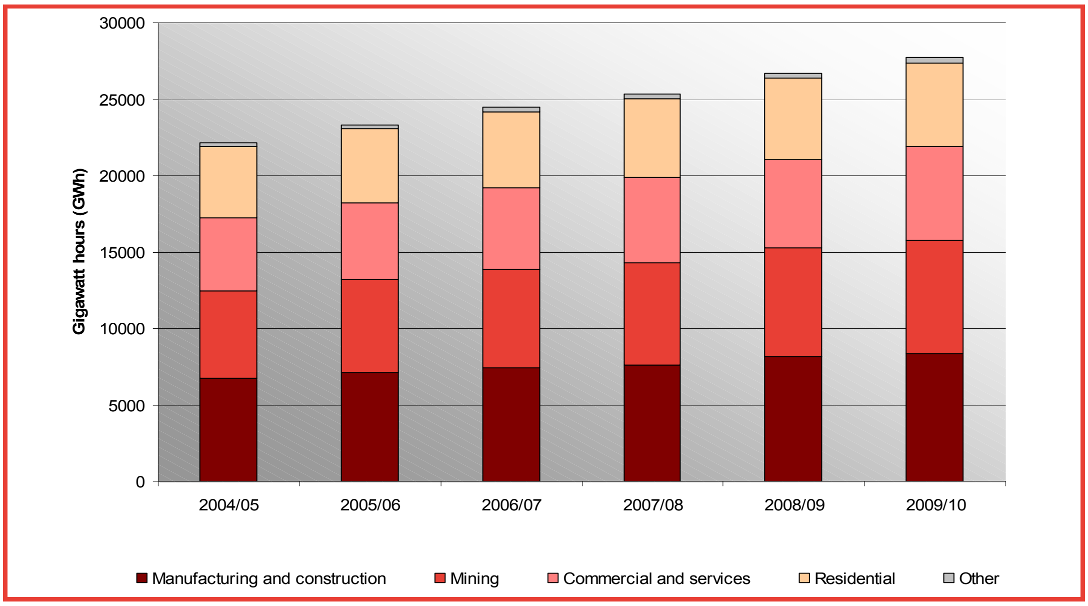

Figure 12: Breakdown of total final electricity consumption by industry

Source: ABARE (2006).

Outlined in Figure 12 is a breakdown by industry of total final electricity consumption for Western Australia over the period 2004/05 to 2009/10. Consumption over the period 2006/07 to 2009/10 was forecast.

Due to its relative complexity and size, the focus of this review will be on the market structures and arrangements within the SWIS, and neither the arrangements in the NWIS or non-interconnected systems will be considered further.

115 AER (2007), pp. 204-205.

Reform process to date[116]

Consistent with the eastern states, Western Australia's electricity industry was historically dominated by a single, vertically integrated utility under government ownership. There was no effective third-party access to electricity networks, no independent entry and no electricity market competition. When in 1993 the Council of Australian Governments decided to reform the electricity industry and create the NEM, it was considered impractical for Western Australia to join.

While electricity markets in the southern and eastern states were seeing large reforms with the introduction of the NEM, Western Australia's electricity markets were not opened to competition for almost a decade longer. This resulted in Western Australia retaining its vertically integrated monopoly structure for far longer than the NEM states. During this time, however, Western Australia did introduce minor reforms into the electricity sector, including:

- Disaggregation of the State Energy Commission into separate electricity and gas corporations – Western Power Corporation and AlintaGas – in 1995;
- Introduction of third party transmission access in 1996 and phasing in third-party distribution access from 1997; and
- Progressive introduction of retail contestability for large consumers connected to the distribution system during the period 1997–2005.

Despite these reforms, competition in wholesale and retail electricity markets remained limited and, until further reforms that followed in 2004, these markets continued to be dominated by the government-owned incumbent, Western Power Corporation.

A lack of competition, in combination with relatively high generation costs (due to relatively expensive coal sources and the remoteness of major gas fields) led to businesses paying high prices for electricity. Over the period 1996/97 to 2003/04 retail prices for large businesses in Western Australia where on average higher than prices in all other jurisdictions excepting the Northern Territory. In 2003/04 real electricity prices for large businesses were 15 to 60 per cent higher in Western Australia than in the eastern states.[117]

In 2001, the government established the Electricity Reform Task Force to review the structure of the electricity market. The *Electricity Industry Act 2004* implemented several of the Task Force's key reforms, namely[118]:

- Disaggregating Western Power into four separate state-owned entities, which took effect on 1 April 2006. These entities are the Electricity Networks Corporation (Western Power), the Electricity Retail Corporation (Synergy),

[116] AER (2007), p.207.

[117] OOE (2004)

[118] http://www.ncc.gov.au/articleZone.asp?articleZoneID=525

the Electricity Generation Corporation (Verve Energy) and the Regional Power Corporation (Horizon Power);

- Providing for the development of a Wholesale Electricity Market in the south-west of the state and creating the WEM Market Rules (the Market Rules);
- Introducing an independent licensing regime for electricity industry participants;
- Establishing an electricity networks access code to facilitate third party access to transmission and distribution networks, which commenced in 2004; and
- Introducing various consumer protection measures.

Market governance bodies

Several key governance bodies exist in the WEM, namely; the IMO, System Management, the Market Advisory Committee and the Economic Regulation Authority. The IMO and System Management are automatically registered as Rule Participants.[119]

<u>Independent Market Operator</u>

The IMO was established pursuant to the *Electricity Industry Act* 2004. A body corporate, the IMO is responsible for the administration and operation of the Western Australian WEM in accordance with the Market Rules. The IMO, *inter alia*, maintains and develops the Market Rules, maintains and develops market procedures, registers Rule Participants and operates the STEM and the Reserve Capacity Mechanism.

<u>System Management</u>

System Management is a ring-fenced entity within Western Power established under the Market Rules. It is responsible for operating the power system to maintain security and reliability. It is also undertakes large customer retailer supply management, including demand side management. Additionally, it has a central role in the scheduling of generator and transmission outages, and managing the real-time operation of the power system.

<u>Market Advisory Committee</u>

The Market Advisory Committee (MAC) is an industry group made up of both Rule Participant and consumer representatives, and is convened by the IMO. The Market Rules outline the functions of the MAC, and the composition of its committee. Primarily, it has the function of advising the IMO on issues pertaining to proposed market rule and procedure changes and general market operation issues. The MAC consists of between 11 and 12 members appointed by the IMO from nominated representatives of generators, retailers, network operators and consumers. The Minister and the Economic Regulation Authority

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[119] IMO (2006), pp. 2-3.

may both appoint representatives to attend meetings of the Market Advisory Committee as observers.

Economic Regulation Authority

The Economic Regulation Authority (ERA) is the independent economic regulator for Western Australia. It regulates monopoly aspects of the gas, electricity and rail industries and licenses providers of gas, electricity and water services. The Authority also inquires into matters referred to it by the State Government. In addition, the Authority has a range of responsibilities in the retailing of gas and surveillance of the wholesale electricity market in Western Australia.

The Market Rules specify certain roles for the ERA in the WEM, included approving maximum and minimum capacity and energy prices, approving efficient costs for the operation of the IMO and System Management, conducting market surveillance, and monitoring and reporting to the Government on the efficiency and effectiveness of the market. This final function is performed by way of an annual Minister's Report.

Legislative corporations

Three key legislative corporations exist in the SWIS as a result of the disaggregation of Western Power into four separate, state-owned entities. Each of these state-owned corporations are key participants in the WEM.

Western Power

The Electricity Networks Corporation, trading as Western Power, is the largest Network Operator in the SWIS. It is responsible for the distribution and transmission of electricity in the SWIS, maintenance of the electricity network and the provision of network access services. A ring-fenced business unit of Western Power (System Management) fulfils the role of System Management. Western Power is also the default Metering Data Agent if another Network Operator does not fill this function.

Synergy

The Electricity Retail Corporation, trading as Synergy, is the largest Market Customer in the SWIS. In most cases, the Rules apply to Synergy as they would for any other Market Customer. The main exception is that Synergy is the only retailer allowed to serve customers that do not have interval meters, since these customers require different load and settlement treatment. Synergy is also the Market Customer that supplies non-contestable retail customers and is the supplier of last resort to the retail market.

Verve Energy

The Electricity Generation Corporation, trading as Verve Energy, is the largest Market Generator in the SWIS. While much of the Market Rules apply to Verve Energy as they would for any other Market Generator, in some instances Verve Energy has specific roles and obligations that IPPs do not. These include:

- Verve Energy's facilities follow a different scheduling process to other generators;
- Verve Energy is required to make its capacity available to System Management to provide ancillary services;
- Verve Energy must operate to balance the entire SWIS in real-time, to the extent it is able; and
- Verve Energy sells electricity to Synergy under State Government contract known as the Vesting Contract (further explained below).

The new Premier of Western Australia has recently suggested that the Government is considering the amalgamation of Synergy and Verve Energy in an attempt to stem the losses arising from the Vesting Contract arrangements between these parties.[120]

Market structure

As at 30th September 2008 there were a total of 30 participants[121] registered with the IMO. These included:

- 14 entities registered as Market Generators only;
- 8 entities registered as Market Customers only; and
- 8 entities registered as both Market Generators and Market Customers.

The key Market Generators, Market Customers and Network Operators in the WEM are outlined in Table 4. The legislative corporations discussed above are highlighted.

Market Generators	
Alcoa	Alinta Sales
Goldfields Power	Griffin Power
Landfill Gas and Power	Perth Energy
Southern Cross Energy	Verve Energy

Market Customers	
Alcoa	Alinta Sales
Clear Energy	Energy Response
Perth Energy	Southern Cross Energy
Synergy	Verve Energy

120 http://www.abc.net.au/news/stories/2008/10/09/2386447.htm

121 http://www.imowa.com.au/PUB_RulePartClassInfo.htm. This excludes the Network Operators, the Regulator, the Market Operator and the System Operator.

Network Operators	
Alinta Sales	Western Power

Table 4: Key market participants

Source: Frontier Economics

2.1.2 Wholesale market arrangements

The WEM became fully operational in September 2006. Its key objective is to facilitate competition and private investment in wholesale electricity generation and purchasing in Western Australia. The WEM was designed to extend and enhance bilateral contracting, which was an important element of the previous industry arrangements. A 'net' pool market was put in place on the expectation that most electricity would be traded through bilateral contracts, with minimal trading around these positions occurring in a day-ahead market. Over the period Sept 2006 – June 2007, on average and approximately[122]:

- 94.3% of energy in the WEM was traded through bilateral contracts; and
- 5.7% of energy in the WEM was traded through the day-ahead and balancing markets (further discussed below).

The WEM's Energy Market, as defined and used in the Market Rules, describes all mechanisms for trading energy[123] in the WEM, and includes transactions made via three key mechanisms:

- Bilateral contracting (which include the Vesting Contract between Synergy and Verve, discussed below);
- Short Term Energy Market (STEM); and
- Balancing.

These three mechanisms relate to three key time frames – these being, respectively:

- Years, months, weeks or days before the Scheduling Day – for Bilateral Contracting;
- Scheduling Day (i.e. the day before the Trading Day) – for the STEM; and
- Trading Day (i.e. real-time) – for Balancing.

The link between the above time frames and the three key trading mechanisms in the WEM is outlined in Figure 13. A participant's Net Contract Position is the sum of its Net Bilateral Position and Net STEM Position. A participant's *actual*

122 IMO (2007), p.17.

123 Bilateral contracting of Capacity Credits and RECs are not considered by the IMO as being part of the WEM's Energy Market.

net position in real-time may vary from its Net Contract Position due to changes in real-time demand and/or supply.

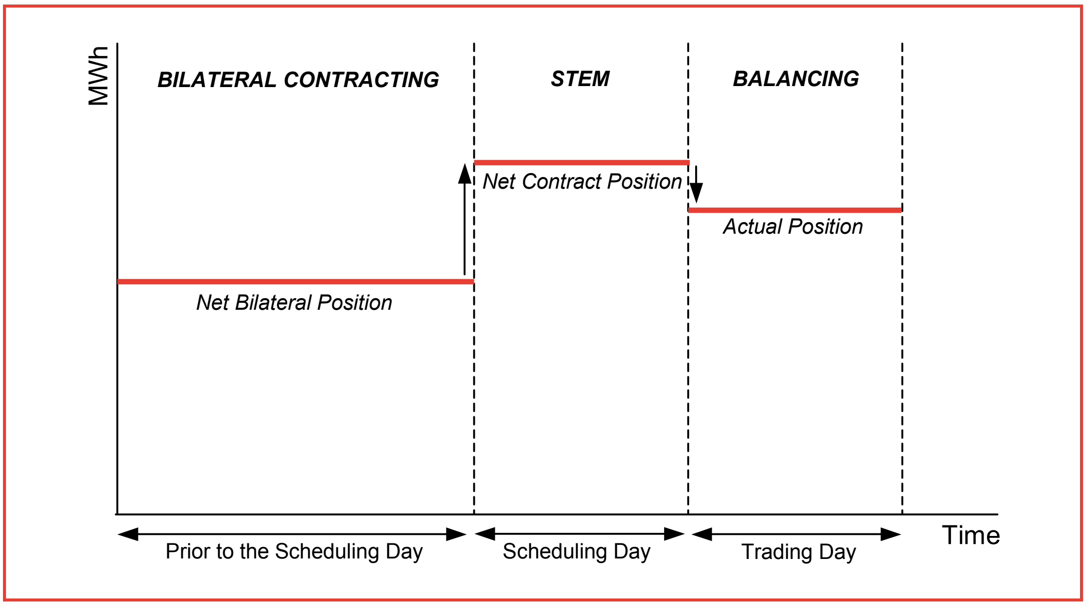

Figure 13: The WEM Energy Market

Source: Frontier Economics

Bilateral contracts

Bilateral contracts are agreements formed between Market Participants for the provision of energy.[124] These contracts are formed on a purely commercial basis, and the IMO has no role or interest in how they are formed, or in the conditions they impose on the parties subject to those contracts. A bilateral contract provides the holders with certainty over their settlement position with respect to that transaction. To the extent that a party cannot fulfil its contractual obligations, either because of generator outage, transmission or network security constraints or low demand, that party will be liable to settle its deviations from contract position with its relevant counterparty(s).[125]

Importantly, the holders of bilateral energy contracts must schedule that energy in the market. To schedule energy for a Trading Day, Market Generators must make a Bilateral Submission to the IMO on the Scheduling Day, being the day *prior* to the day on which the Trading Day begins. All Bilateral Submissions must be balanced, in the sense that the total energy to be supplied to the network (by the Market Generator) must match the total energy to be taken from the network (by Market Customers who are counterparties to the Market Generator). A Market Participant that is both a Market Generator and a Market Customer and who wishes to cover its own load with its own generation must state this in its

[124] For present purposes, this section focuses on bilateral contracts for energy only. However, participants can and do also bilaterally trade certified reserve Capacity Credits in order to enable them to satisfy their Individual Reserve Capacity Requirements. See below and IMO (2006), p.28.

[125] Note that the IMO has no involvement in this process.

Bilateral Submission. The required information in a Bilateral Submission includes:

- The identity of the submitter;
- The total loss adjusted net energy[126], in MWh, to be supplied by the submitter; and
- The total loss adjusted net energy, in MWh, assigned to each Market Participant supplied by that submitter.

The total loss-adjusted net energy to be supplied in a Bilateral Submission plus the sum of the total loss adjusted net energy to be consumed under a given Bilateral Submission must equal zero. This condition ensures that submissions are balanced. Once a Bilateral Submission is accepted, the energy is scheduled into the market by the IMO.[127]

The Vesting Contract between Verve Energy and Synergy

As part of the disaggregation of Western Power Corporation and the creation of Synergy and Verve Energy, the Government imposed vesting arrangements between Verve Energy and Synergy as a transitional mechanism to support the development of the WEM.[128] The Vesting Contract provides for the wholesale supply of both energy and Capacity Credits from Verve Energy to Synergy.

The objectives of the Vesting Contract included:

- To hedge the supply costs of the then-existing retail customers of Western Power;
- To mitigate the market power of Western Power Generation (now Verve Energy); and
- To provide for a smooth transition to the WEM by providing incentives to both Verve Energy and Synergy to progressively negotiate energy supply agreements on a commercial basis.[129]

The Vesting Contract initially covered the load of all customers on regulated tariffs as well as all customers on market contracts that Synergy inherited from Western Power Corporation. The volume of energy and Capacity Credits under the Vesting Contract has and will decline as:

- Retail sales agreements that are inherited by Synergy expire;
- Contestable tariff customers accept retail sales agreements from other retailers; and

126 The loss adjustments are based on static loss factors, fixed for a year, and reflect average marginal losses between a fixed Reference Node and each injection or off-take point in the SWIS. These are set annually by Network Operators and published by the IMO.

127 IMO (2006), pp. 44-45.

128 Office of Energy, *Overview of the Vesting Arrangements*, September 2006, p.1.

129 Office of Energy, *Overview of the Vesting Arrangements*, September 2006, p.2.

- Synergy undertakes displacement in accordance with the "Displacement Mechanism" defined in the Vesting Contract.[130]

The Vesting Contract is priced on the basis of a 'netback' pricing arrangement according to which Verve Energy is paid the residual of Synergy's sales revenues after accounting for efficient retail, network and other costs.[131] That is, Verve Energy receives:

- Synergy's revenues from the relevant tariff and inherited retail contract sales;
- *Less* a defined allowance for Synergy's costs, including an efficient profit margin, which is retained by Synergy;
- *Less* networks costs paid to Western Power Networks; and
- *Less* other specified market and regulatory costs.[132]

An implication of the netback pricing approach is that changes to regulated tariffs will affect the price that Verve Energy ultimately receives under the Vesting Contract.

Short Term Energy Market

The Short Term Energy Market (STEM) is an energy-only forward market operated by the IMO on the Scheduling Day, designed to facilitate trading by Market Participants around their Net Bilateral Positions. Participation in the STEM is open to all Market Participants, but is not compulsory for any participant. The STEM is run for every Trading Interval of the Trading Day, and determines a single clearing price for each Trading Interval, as well as the quantities that sellers will sell to the IMO and that buyers will purchase from the IMO. The STEM auction is designed such that IMO purchases the same amount of energy it sells and hence has zero net exposure.

As noted above, a participant's Net Bilateral Position as modified by its purchases or sales in the STEM forms its Net Contract Position. For example, assume a Market Generator has made a Bilateral Submission to the IMO indicating that it will supply 100 MWh of energy, but that half of this (i.e. 50 MWh) will be supplied to its own load. Thus, its Net Bilateral Position is to supply 50 MWh of energy. If this participant then sells an additional 10MWh of energy in the STEM, its Net Contract Position will be to supply the market with 50MWh + 10MWh = 60MWh of energy.

All participants who choose to participate in the STEM must submit a STEM Submission on the morning of the Scheduling Day. A STEM Submission comprises the following information:[133]

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130 Office of Energy, *Overview of the Vesting Arrangements*, September 2006, pp.4-8.

131 Office of Energy, *Overview of the Vesting Arrangements*, September 2006, pp.8-10.

132 Office of Energy, *Overview of the Vesting Arrangements*, September 2006, p.8.

133 IMO (2006), pp. 46-47.

- A Portfolio Supply Curve for each Trading Interval of the Trading Day: A Portfolio Supply Curve is a schedule of price-quantity pairs, where the cumulative quantity offered represents all the energy being offered to the market from that participant's generation resources. If a participant is only a Market Customer, a zero quantity must be entered. Prices submitted in the Portfolio Supply Curve must be *less* than the Maximum STEM price or the Alternative Maximum STEM price, depending on whether generation is a non-liquid (coal, gas) or liquid (diesel) facility, respectively. Prices submitted must be greater than the Minimum STEM Price;[134]
- A Portfolio Demand Curve for each Trading Interval of the Trading Day: A Portfolio Demand Curve is a schedule of price-quantity pairs, where the cumulative quantity bid represents all the energy being purchased from the market by that participant. If a participant is only a Market Generator, a zero quantity must be entered;
- A fuel declaration: This states what fuel each dual-fuelled generator was assumed to be using when determining its Portfolio Supply Curve;
- An ancillary service declaration: Market Participants who are dual-fuelled providers of ancillary services must declare, for each Trading Interval, how much of their required quantity is assumed to be provided by liquid fuelled generation and how much is assumed to be provided by non-liquid fuelled generation; and
- An availability declaration: If a Market Participant is not offering generation capacity to the market and there is no obvious reason for this, the Market Participant must declare this.

Instead of submitting standalone STEM bids and offers, participants seeking to participate in the STEM must submit Portfolio Supply and Demand curves. This is because of the difficulty the IMO faces in determining whether participants are bidding within their cost caps in light of both the following features of the WEM:

- Liquid fuelled generation may be offered into the STEM at a higher maximum price than non-liquid fuelled generation;[135] and
- Participants submit only their Net Bilateral Positions to the IMO, rather than their gross positions.

Without information about a participant's entire Portfolio Demand and Supply curves, it would be difficult for the IMO to check whether participants were

[134] The Alternative Maximum STEM Price is greater than the Maximum STEM Price to reflect the higher fuel costs that liquid relative to non-liquid facilities face. As at 30th September 2008 the Maximum STEM Price is currently $286.00/MWh and the Alternative Maximum STEM Price is currently $763/MWh. The Minimum STEM Price is currently -$286.00/MWh

[135] That is the Alternative Maximum STEM Price (which is the liquid-fuelled maximum price) is *greater* than the Maximum STEM Price (which is the non-liquid fuelled maximum price).

offering their non-liquid fuelled plant at prices above the applicable (non-liquid fuelled) Maximum STEM Price.[136]

To prevent such gaming by participants, the IMO derives participants' STEM offers and bids from each participant's (i) Net Bilateral Position, (ii) Portfolio Supply Curve and (iii) Portfolio Demand Curve. In order to derive a participant's STEM offers and bids, the IMO firstly determines the participant's *Net* Supply Curve by subtracting the participant's Portfolio Demand Curve from their Portfolio Supply Curve. An example of this for a participant that submits both a Portfolio Demand and Supply curve is depicted in Figure 14.

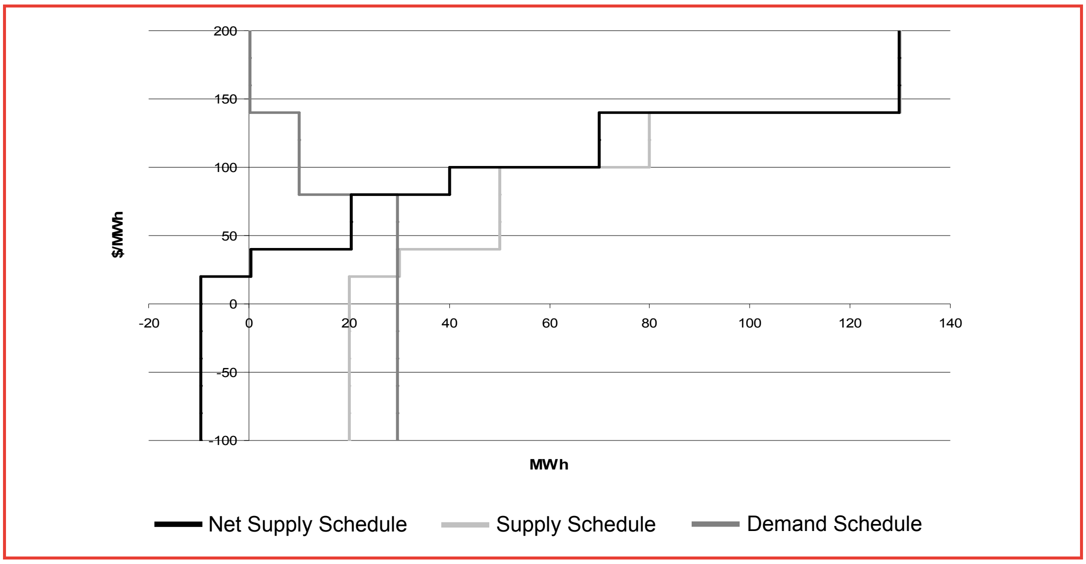

Figure 14: Defining the Net Supply Curve

Source: Frontier Economics

Once the participant's Net Supply Curve has been determined, the IMO defines a participant's STEM offers and bids relative to that participant's Net Bilateral Position. Specifically, quantities on a participant's Net Supply Curve *above* that participant's Net Bilateral Position are defined as STEM offers, while quantities on a participant's Net Supply Curve *below* that participant's Net Bilateral Position are defined as STEM bids.

The STEM bids and offers for the participant outlined in Figure 14 are shown graphically in Figure 15, where this participant's Net Bilateral Position is assumed to be 20MWh.

The market-clearing STEM price is defined at the point where cumulative STEM offers equal cumulative STEM bids. Cumulative STEM offers are determined by summing and arranging, from lowest to highest, all participants' individual STEM offers. Cumulative STEM bids are determined by summing and arranging, from higher to lowest, all participants' individual STEM bids.

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136 IMO (2006), p.46.

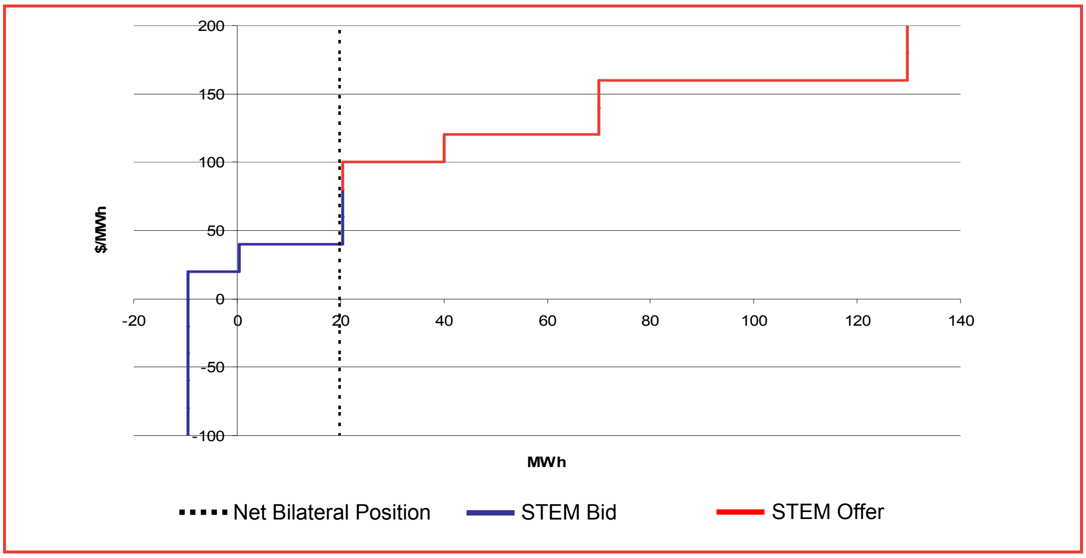

Figure 15: Defining STEM offers and bids

Source: Frontier Economics

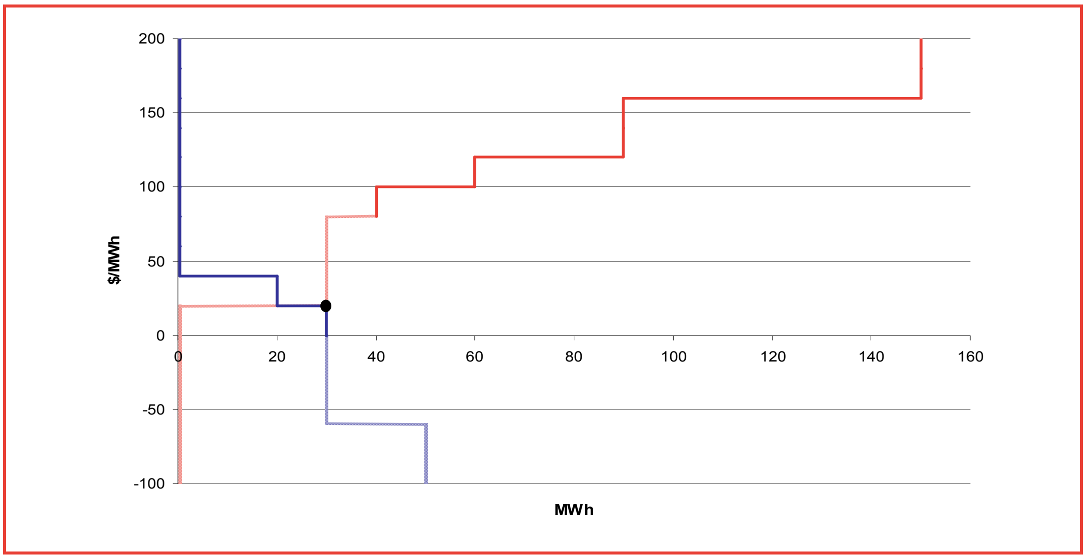

Figure 16: Defining the STEM market-clearing price

Source: Frontier Economics

The intersection of cumulative STEM bids (demand) and cumulative STEM offers (supply) defines the STEM Price – this is illustrated in Figure 16, where the STEM Price is $20/MWh. For a comprehensive numerical example illustrating how the IMO determines participants' STEM offers and bids from their Portfolio Supply and Demand Schedules and their Net Bilateral Positions, please see Appendix B.

Participants scheduled in the STEM are required to settle their relative amounts with the IMO at the market-clearing price. Net suppliers receive the STEM Price while net consumers pay the STEM Price. A Market Participant's Net Contract Position is equal to its Net Bilateral Position as modified by its net purchases or sales in the STEM.

Balancing

From 14:00 on the Scheduling Day through to the end of the Trading Day, System Management is able to schedule Verve Energy plant and, if necessary, issue dispatch instructions to other Market Participants so as to ensure that supply matches demand in real time. That is, System Management can use these resources to *balance* the system. Two forms of deviation from Net Contract Position are important in this regard:

- Balancing deviations; and
- Unauthorized deviations.

Balancing deviations

Balancing deviations are deviations that occur as a result of instructions from System Management. When a deviation from Net Contract Position occurs, participants are settled with a price that may be different to the STEM price, depending on their status:

- Verve Energy, non-scheduled generators (such as wind farms) and non-dispatchable, non-interruptible and non-curtailable loads are all settled at the Marginal Cost Administrative Price (MCAP) if requested to deviate by System Management; while
- IPP facilities are settled on a pay-as-bid basis if requested to deviate by System Management. That is, the IMO determines an IPP's settlement price according to its previously submitted generation schedules.

The primary reason for settling balancing services provided by Verve Energy differently to balancing services provided by IPPs is due to Verve Energy's (virtual) monopoly status as the provider of balancing services in the WEM. To prevent Verve Energy from abusing its dominant position in providing balancing services (for instance, by offering balancing at the Maximum or Alternative Maximum STEM Price), its settlement price for balancing (MCAP) is a function of the (competitive) STEM Price. Since IPPs only rarely provide balancing in the WEM, they are deemed to be price takers with respect to balancing services, and hence are paid their bid prices.

MCAP is explicitly determined whenever real-time effective demand deviates from expected demand. In the past, MCAP was only calculated if and when real-time effective demand deviated from expected demand by more than ±5%. This requirement was superseded by a recent rule change.[137]

[137] See rule change number RC_2008_05 "Calculation of MCAP" accessed from: http://www.imowa.com.au/Attachments/RuleChange/RuleChange_2008_05.htm on 10 October 2008.

MCAP is determined using the same methodology as is used in calculating the STEM Price – that is, MCAP is defined by the intersection of cumulative supply and demand. However, in such cases, demand is *actual* cumulative demand (referred to as 'deemed' cumulative demand), rather than *expected* cumulative demand. That is, deemed cumulative demand reflects expected cumulative demand that has been updated by real-time conditions.

To illustrate this point, consider Figure 17. Let the intersection of cumulative supply and cumulative demand originally intersect at 2,000 MWh and hence let the STEM price be equal to $150/MWh. In the first scenario, deemed cumulative demand intersects cumulative supply at 2,200 MWh. In this case, MCAP will be set at $150/MWh and hence will be equivalent to the STEM price. In the second scenario, deemed cumulative demand intersects cumulative supply at 2,500 MWh. In this case, MCAP will be set at $180/MWh. Since the difference between expected and real-time demand is usually small, MCAP is typically set at or near the STEM price.

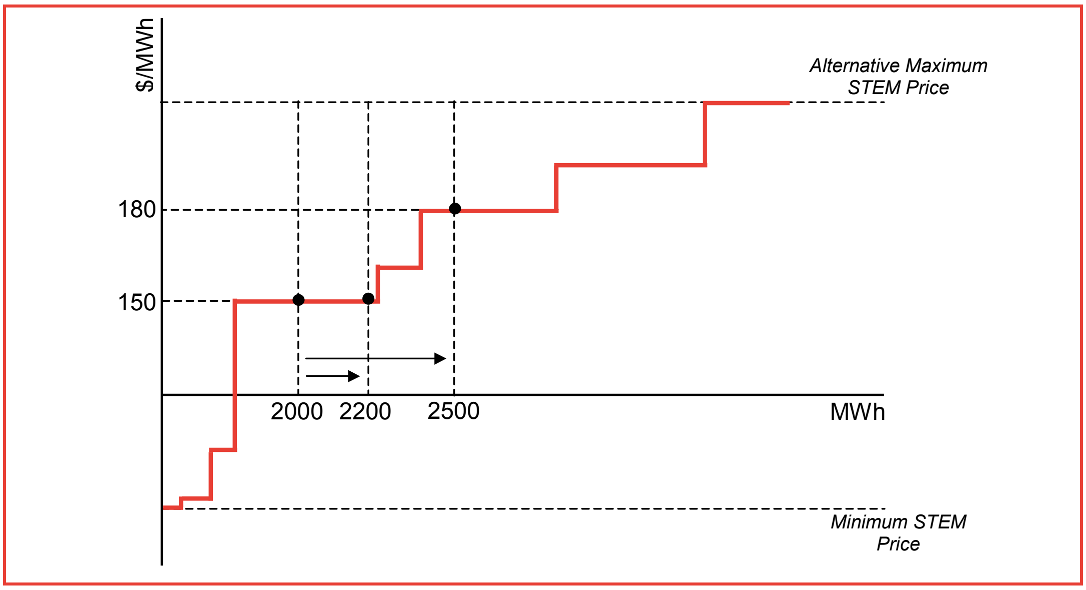

Figure 17: Determining MCAP

Source: Frontier Economics

Unauthorized deviations

Unauthorized deviations by IPPs from their Net Contract Position is discouraged in the WEM through the use of two unattractive deviation prices – the Upward Deviation Price (UDAP) and the Downward Deviation Price (DDAP).

DDAP is the settlement price for deviations below Net Contract Position and is defined in the Market Rules. DDAP is equal to 1.3 x MCAP during peak periods and 1.1 x MCAP during off-peak periods. If an IPP supplies less than its scheduled quantity without authorization from System Management, that IPP must pay the IMO for that energy at DDAP.

UDAP is the settlement price for deviations above Net Contract Position and is defined in the Market Rules. UDAP is equal to 0.5 x MCAP during peak periods and zero during off-peak periods. If an IPP supplies more than its scheduled quantity without authorization from System Management, that IPP will be paid by the IMO for that energy at UDAP.

The close relationship between STEM, MCAP, DDAP and UDAP prices is illustrated by the WEM's annual price-duration curve, reproduced in Figure 18. Note that MCAP generally follows the same shape as the STEM price but is often higher, indicating that real-time effective demand more often than not *exceeds* total expected demand. Also note that, by definition, MCAP is bounded by DDAP and UDAP.

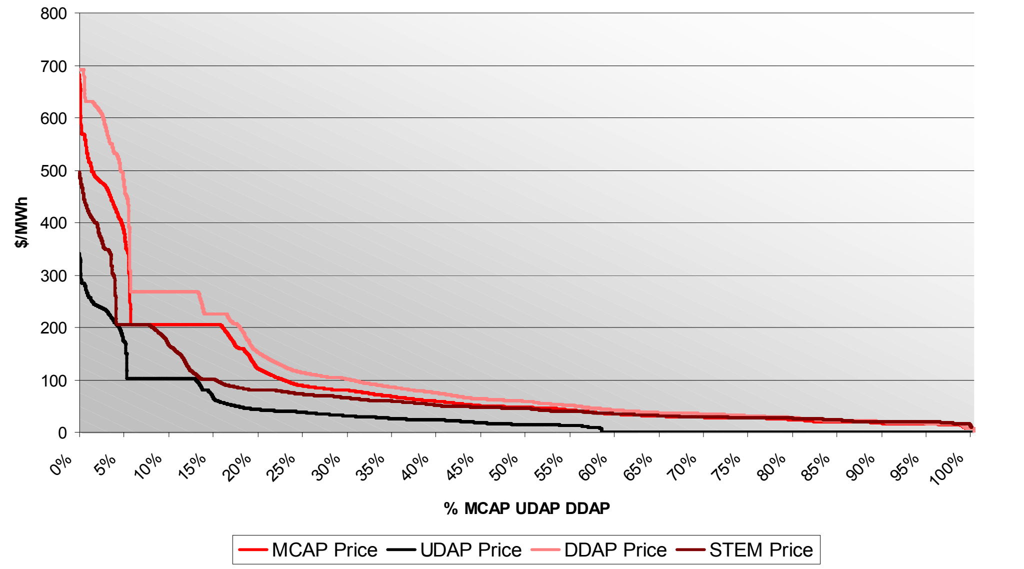

Figure 18: WEM price-duration curve (2007/08)

Source: Frontier Economics

The IMO's settlement process will not be zero-sum, as the UDAP and DDAP prices as well as the pay-as-bid obligation create a mismatch between income received and payments made. Given that IPP resources are not generally issued dispatch instructions (balancing is primarily provided by Verve Energy) and that deviations prices (UDAP and DDAP) generate income, the IMO will tend to recover more revenue than it pays out. Excess market revenue is redistributed to Market Participants each month through a non-STEM reconciliation payment.

Reserve Capacity Mechanism

Unlike the NEM, which is an energy-only market, the WEM has a capacity market to ensure adequate generation capacity exists to meet expected demand in a given time period. To this end, the IMO administers a Reserve Capacity Mechanism, which aims to ensure that the SWIS has adequate installed capacity available from generators and demand-side management options from loads at all times. The Reserve Capacity Mechanism is necessary to ensure adequate capacity exists, since prices in the STEM are capped at levels far below what would be required to support investment in an energy-only market. The IMO determines the capacity required in each year so as to:

- Ensure that forecast peak demand after the outage of the largest generation unit in the SWIS can be met, while maintaining some residual frequency management capability (e.g. 30 MW), in nine years out of 10; and
- Limit energy shortfalls to 0.002% of total annual energy consumption.

Annual Reserve Capacity Requirements are specified annually by the IMO based on the capacity requirements of the SWIS for the succeeding 10 years. Each Market Customer is allocated a share of this Reserve Capacity Requirement, called its Individual Reserve Capacity Requirement, and is required to secure Capacity Credits to cover its requirement. Capacity Credits are effectively (i) installed capacity by Market Generators or (ii) Demand Side Management (DSM) by Market Customers. This installed capacity and/or DSM must be registered with the IMO.

To fulfil its Individual Reserve Capacity Requirement, a Market Customer can either procure Capacity Credits bilaterally from Capacity Credit suppliers, or it can purchase Capacity Credits from the IMO. The IMO may run an annual auction to procure Capacity Credits for on-sale to Market Customers if the requirement for Capacity Credits is not met through bilateral trade.

Generation and DSM facilities capable and willing to contribute capacity in a given year must apply to the IMO for Certified Reserve Capacity status applicable to that Capacity Year. This certification indicates the contribution of a facility in meeting the capacity requirement in a given Capacity Year. Certified Reserve Capacity that is accepted by the IMO is converted into Capacity Credits. At that time, certain obligations are bestowed on the facility holding those credits. As set out in section 4.11 and 4.12 of the Market Rules, these obligations include:

- In the case of generators (other than intermittent generators), to make that capacity available to the market, in the form of bilateral contract positions, STEM submissions and capacity contracted to provide ancillary services, and to make any unscheduled capacity available in real-time if required and subject to adequate notification being given;
- In the case of DSM, to make that capacity available in real-time if required and subject to adequate notification being given; and
- In the case of intermittent generators, to generate to the greatest extent possible when requested to do so by System Management.[138]

If enough Certified Reserve Capacity is traded bilaterally to meet the Reserve Capacity Requirements of the SWIS, then no Reserve Capacity Auction will be held, and all the Certified Reserve Capacity accepted through the bilateral trade process will be granted Capacity Credits. To date, no Reserve Capacity Auction has been required. The price paid by the IMO for Capacity Credits is defined in the Market Rules to be 85% of the Maximum Reserve Capacity Price. The

[138] IMO (2006), p.29.

current Maximum Reserve Capacity Price is $122,500/year[139], and thus Capacity Credits are currently paid $11.89/MWh for every hour in a 365-day year.

If the total capacity traded bilaterally does not fully cover the total Reserve Capacity Requirement, then any bilaterally traded reserve capacity is assigned Capacity Credits, and the shortfall between the Reserve Capacity Requirement and the quantity of bilaterally traded reserve capacity is procured in a Reserve Capacity Auction.

2.1.3 Retail market arrangements

Retail competition

The retail market in Western Australia has been progressively opened to retail competition since 1997. The timing for the introduction of retail competition is set out in Table 5.

Date	Threshold for competition
1 July 1997	≥ 10 MW average demand
1 July 1998	≥ 5 MW average demand
1 January 2000	≥ 1 MW average demand
1 July 2001	≥ 230 kW average demand
1 January 2003	≥ 34 kW average demand
1 January 2005	> 50 MWh annual consumption

Table 5: Timetable for the introduction of retail competition

Source: ESAA (2007).

Currently, all customers that consume more than 50 MWh per annum are contestable. This means that around 12,500 customers, or 1.5 per cent of total customers in Western Australia, are contestable.[140] Because these customers are large users of electricity, they may represent up to 60 per cent of total energy consumption.[141]

Contestable customers can be supplied either by the incumbent retailers – Synergy for customers inside the SWIS and Horizon Power for customers outside the SWIS – or new entrant retailers. In its most recent annual report on retailer performance, the ERA noted that there were a total of five retailers operating in the Western Australian market in 2006/07: Synergy, Horizon Power, Rottnest Island Authority, Alinta Sales and Perth Energy. Of the new entrant retailers, Alinta Sales had over 1,000 customers and Perth Energy had around 50

[139] http://www.imowa.com.au/10_5_1_e_price_limits.htm

[140] ERA, *2006/07 Annual Performance Report: Electricity Retailers*, January 2008.

[141] ERA, *2006/07 Annual Performance Report: Electricity Retailers*, January 2008.

customers.[142] In total, the customers that Alinta Sales and Perth Energy had gained represented around 7 per cent of the estimated contestable market in 2006/07.[143]

Customers that consume 50 MWh or less are not contestable, and are supplied by Synergy within the SWIS or Horizon Power outside the SWIS. The Minister for Energy is currently undertaking the Electricity Retail Market Review (ERMR), which includes a study of the introduction of Full Retail Competition (FRC) in electricity. The Office of Energy has responsibility for completing this review and preparing recommendations for the Minister's consideration. A draft recommendations report on the introduction of FRC should be released shortly. The new government's position on the introduction of FRC is as yet unclear.

Tariff regulation

Currently, regulated tariffs exist for all customer groups in Western Australia:

- Non-contestable customers in the SWIS (those consuming 50 MWh per annum or less) must be supplied by Synergy at the regulated tariff;
- Contestable customers in the SWIS that consume between 50 MWh and 160 MWh per annum can choose to negotiate a contract with any retailer at a negotiated tariff, or can opt for supply from Synergy at the regulated tariff; and
- Contestable customers in the SWIS that consume more than 160 MWh per annum can choose to negotiate a contract with any retailer at a negotiated tariff. Regulated tariffs also exist for these customers, but Synergy is not obliged to supply these customers at the regulated tariff.

Similar obligations are imposed on Horizon Power for customers outside the SWIS. The Government has a uniform tariff policy, where some of the tariffs within and outside of the SWIS are the same for the same class of customers. Tariffs within the SWIS are set out in the *Energy Operators (Electricity Retail Corporation) (Charges) By-laws 2006* and tariffs outside the SWIS are set out in the *Energy Operators (Regional Power Corporation) (Charges) By-laws 2006*. In both regions, tariffs are defined for particular classes of customers. For instance, the residential tariff within the SWIS is the A1 tariff and the residential tariff outside the SWIS is the A2 tariff. Due to the uniform tariff policy, the A1 tariff and the A2 tariff are equivalent. Similarly, the low/medium voltage business tariff within the SWIS is the L1 tariff and the low/medium voltage business tariff outside the SWIS is the L2 tariff. Due to the uniform tariff policy these are also equivalent. A full set of tariffs is sets out in the By-laws noted above.

The Minister for Energy is currently undertaking the ERMR, which includes a review of electricity retail tariff arrangements. The Office of Energy's draft recommendations report to the Minister for Energy recommends that regulated

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[142] ERA, *2006/07 Annual Performance Report: Electricity Retailers*, January 2008.

[143] ERA, *2006/07 Annual Performance Report: Electricity Retailers*, January 2008.

tariffs should increase in order to reflect increases in the costs of supplying electricity. The Office of Energy recommended that residential tariffs should increase by 47 per cent in 2009/10, and tariffs for other small use customers should increase by between 21 per cent and 44 per cent. The former Premier, Alan Carpenter, instead affirmed that there would be a 10 per cent increase in tariffs from 2009/10 with further annual increases to be phased in over a six to eight year period. The new government's position on the cost-reflectivity of retail tariffs is as yet unclear.

2.1.4 System Operation

As noted above, system operation functions in the WEM are performed by System Management, a ring-fenced entity located within Western Power. System Management's principal function within the SWIS is the maintenance of power system security and reliability. To achieve this, System Management must operate the power system within a technical envelope that accounts for the operating and ancillary service standards in the Market Rules and technical codes, as well as equipment and security limits provided by network operators and other participants.[144] The key responsibilities of System Management and other entities in relation to maintaining system security and reliability are discussed below.

Dispatch

Under normal system operating conditions, system management's primary responsibility is to manage dispatch in real-time to ensure that power system security is maintained while, to the extent possible, facilitating electricity trading in accordance with participants' bilateral contract and STEM positions.[145] Ideally, participants would follow their net contract schedules in real-time (in which consumption and production of electricity must be balanced across the WEM). However, this may not occur due to transmission outages or constraints, or plant outages. Additionally, demand in real-time is likely to deviate from forecast, requiring System Management to adjust participants' dispatch targets to maintain system frequency and voltage control.[146]

In general, System Management will only issue dispatch instructions to Verve Energy and parties with whom it has Balancing Support contracts.[147] Otherwise, System Management will only issue dispatch instructions to other participants where:

- System Management lacks the capability to maintain a secure and reliable power system using Verve Energy resources, Balancing Support contracts and contracted ancillary services (see below); or

[144] IMO (2006), p.21.

[145] IMO (2006), p.21 and p.57.

[146] IMO (2006), p.57.

[147] IMO (2006), p.59.

- The only unscheduled Verve Energy facilities would run on expensive liquid fuel (i.e. diesel), while other suppliers have unutilised non-liquid fuel capacity.[148]

Following each Trading Day, System Management is required to provide the IMO with a wide range of information relating to the calculation of balancing prices and market settlement.[149] This includes dispatch instructions issued to non-Verve Energy generators and the reasons for those instructions. System Management is also required to monitor the compliance of participants with dispatch instructions and to advise the IMO of any non-compliance.[150]

Ancillary services

System Management is responsible for proposing requirements for ancillary services and procuring ancillary services following approval of those requirements by the IMO.[151] Ancillary services costs are recovered by the IMO from participants through the settlements process, as described below. The types of ancillary services defined in the Market Rules are:

- Load Following – the primary real-time service for balancing supply and demand, which is typically provided by units operating under Automatic Generation Control or manual control. The nearest equivalent in the NEM would be regulation raise and lower Frequency Control Ancillary Services (FCAS);
- Spinning Reserve – capacity in reserve to respond rapidly in the event of a forced unit outage. This service is typically provided by on-line generation capacity, dispatchable load and interruptible load. The nearest equivalent in the NEM would be contingency raise FCAS;
- Load Rejection Reserve – generation capacity capable of quickly reducing output if a system fault results in the loss of load. This service is particularly important in the WEM overnight when most units are operating at minimum loading levels and have no capability to decrease their output in a short time frame. The nearest equivalent in the NEM would be contingency lower FCAS;
- Dispatch support – ensures voltage levels around the power system are maintained. The nearest equivalent in the NEM would be Network Control Ancillary Services (NCAS); and
- System restart – to enable part of the power system to be re-energised following a system-wide blackout. The NEM has a similar service (System Restart Ancillary Service (SRAS)).[152]

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148 IMO (2006), p.59.

149 IMO (2006), p.60.

150 IMO (2006), p.61.

151 IMO (2006), p.21.

152 IMO (2006), p.22.

In addition, System Management is required under the Market Rules to maintain Ready Reserve, which is additional non-synchronised capacity that can provide energy within 15 minutes of a contingency.[153]

To date, System Management has procured most of the required ancillary services from Verve Energy under informal arrangements.[154] Under the Market Rules, System Management may procure ancillary services from other parties if Verve Energy lacks sufficient resources or if other parties can provide the services at a lower price.[155] The Market Rules also require System Management to document a procedure to be followed when determining the ancillary services requirement and procuring ancillary services.[156] System Management is currently in the process of developing a procurement strategy for ancillary services.

The IMO allocates the monthly costs of various ancillary services to participants as follows:

- Load following costs are allocated in proportion to each participant's monthly contributing quantity, which is the sum of its metered load and metered non-scheduled generation. Load following costs are not allocated to scheduled generation;
- Spinning reserve costs are allocated to generators in proportion to the deemed risk each generator imposes on the system, based on its output in each Trading Interval over the month. The spinning reserve cost allocation methodology is outlined in Appendix 2 of the Market Rules; and
- Other ancillary services costs are recovered based on metered consumption on a monthly basis.[157]

Short and medium term planning

The IMO is obliged to forecast generation adequacy over a 10-year period and to ensure sufficient reserve capacity is procured. However, System Management is responsible for planning capacity availability over the short to medium term.[158]

Projected Assessment of System Adequacy (PASA)

Medium term PASA provides an integrated assessment of system security and reliability over a rolling 36-month time horizon. Medium term PASA reports the

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153 IMO (2006), p.22.

154 System Management also inherited two contracts for spinning reserve with other participants that predated the start of the WEM - see ERA (2007b), pp. 40-41.

155 Clause 3.11.8.

156 Clause 3.11.14.

157 IMO (2006), p.23.

158 IMO (2006), p.23.

available level of generation and transmission capacity each week, and is updated monthly. The adequacy of this capacity is assessed for high, medium and low demand levels.[159]

Short term PASA provides similar information but over a three-week time horizon, with results being reported for four 6-hour periods per day and updated at least once per week.[160]

Market participants and network operators are obliged under the Market Rules to provide information to System Management to facilitate the PASA processes. The short- and medium-term PASA information is published weekly and monthly respectively on the IMO website.[161]

Outage planning and scheduling

System Management is responsible for compiling a list of all equipment subject to outage scheduling, including partial outages and de-ratings. This list is based on information provided by participants as part of the medium term PASA process (ie three years ahead).[162]

Most planned outages are notified to System Management well in advance (more than one year), but where notification does not occur until closer to real-time, System Management has the right to reject outage scheduling applications. In these cases, participants can request that the IMO re-assess the decision.[163]

If System Management cannot determine an outage plan that accommodates the requests of all participants, it will first seek to negotiate with the relevant participants.[164]

Outages that are scheduled cannot proceed without final approval from System Management two days prior to their commencement.[165] Outages that are approved will reduce the reserve capacity obligations of the relevant participant accordingly. If System Management decides to delay or cancel scheduled outages for system security reasons (see below), the affected party may apply for compensation for additional maintenance costs only (i.e. not for opportunity costs). This compensation is funded from customers based on monthly energy purchases.[166] All non-approved outages that occur are considered forced outages.

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159 IMO (2006), p.23.

160 IMO (2006), p.23.

161 IMO (2006), pp.23-24.

162 IMO (2006), p.24.

163 IMO (2006), p.25.

164 IMO (2006), p.25.

165 IMO (2006), p.25.

166 IMO (2006), p.26.

Participants are required to inform System Management of any forced outages as soon as practical and may need to refund applicable Reserve Capacity payments.[167]

Abnormal system operating states

The preceding discussion described the role of System Management and other parties under normal operating conditions. However, System Management has different powers and responsibilities depending on which of three operating states the power system falls within:

- Normal Operating State – when the power system is in a secure and reliable operating state. The SWIS is in Normal Operating State when System Management considers that:
  - Voltage magnitudes and MVA flows are within applicable Security Limits;
  - All other electric plant impacting the SWIS is operating within applicable Equipment Limits and Security Limits;
  - The configuration of the SWIS is such that the severity of any potential fault is within the capability of circuit breakers;
  - Frequency is within the normal operating frequency band; and
  - Ancillary Services Requirements are being met and conditions in the SWIS are secure in accordance with the requirements of the Technical Envelope.

  In this state, as discussed above, System Management is required to dispatch the market based on merit order and observe normal security standards and operating limits;
- High-Risk Operating State – when operating the system in its normal operating range would expose the system to higher than normal risks in the event of a plant or network outage. In this state, System Management may take steps to increase the security of the power system such as apply different security limits and cancel planned outages; and
- Emergency Operating State – when operating the system in its normal operating range would require involuntary load shedding. In this state, System Management may take whatever steps are necessary to restore the power system to a normal operating state, such as directing market participants and network operators, and cancelling outages.[168]

In high-risk and emergency states, System Management has greater freedom to issue dispatch instructions to IPPs (i.e. to generators other than Verve Energy). While the Rules do not mention explicit compensation for complying with

[167] IMO (2006), p.26.

[168] IMO (2006), p.21.

directions, participants are compensated to the extent that directions involve balancing deviations (for which IPPs are paid on a pay-as-bid basis) or the provision of ancillary services.

System Management is obliged to determine the state of the operating system and must inform the market and the IMO of any changes via Dispatch Advisories. Dispatch Advisories include a statement of the operating state during an event and instructions to Market Participants on how to respond. The Market Rules recognise that in certain cases System Management will have to react immediately to a given situation and as such will not be able to issue a Dispatch Advisory until after the event. In addition, System Management is required to provide reports to the IMO on incidents involving Emergency Operating States.

Investigations into major disturbances

The IMO coordinates investigations into major disturbances on the power system and can require System Management and participants to provide the IMO with a report explaining events and their actions surrounding such events. These reports are to be published on the IMO's website.[169]

Every three months, System Management is required to provide the IMO with a report summarising all instances of involuntary load shedding, shortages of ancillary services and Emergency Operating States that occurred, as well as the actions taken in response by System Management.[170]

2.1.5 Network Regulation

Access Code and Access Arrangement

The *Electricity Networks Access Code* 2004 (Access Code) was made on 30 November 2004 under section 104(1) of the *Electricity Industry Act* 2004 and has subsequently been amended several times.[171] The objective of the Access Code is to promote the economically efficient investment in, and operation and use of, networks and services of networks in Western Australia, and to promote competition in electricity retail and wholesale markets.[172]

The Access Code prescribes commercial arrangements, including charges, that apply in respect of electricity generators and retailers accessing regulated or

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169 IMO (2006), p.26.

170 IMO (2006), p.27.

171 The original version of the Access Code is available from the West Australian Government Gazette at: http://www.slp.wa.gov.au/gazette/gazette.nsf/gazlist/2C360789573C223148256F5C0010ED84/$file/gg205.pdf. The ERA website provides Gazette references for the original Access Code and subsequent amendments at: http://www.era.wa.gov.au/2/306/48/electricity_net.pm. An unofficial consolidated version of the Access Code is available from the OOE website at: http://www.energy.wa.gov.au/2/3194/64/electricity_acc.pm.

172 See the ERA website at: http://www.era.wa.gov.au/1/264/48/electricity.pm.

'covered' electricity networks in Western Australia. At the commencement of the Access Code, the only covered network was the South West Interconnected Network (SWIN)[173] within the SWIS, but there is potential for other networks to be covered.[174]

Under chapter 5 of the Access Code, Western Power is required to propose an access arrangement that describes the terms and conditions of access to the SWIN. This includes the following:

- Terms of a standard access contract for each covered 'reference' service;
- Service standard benchmarks for each reference service;
- Details of the applicable price control and pricing methodology;
- Current price list;
- An applications and queuing policy for network access; and
- A capital contributions policy.[175]

Some of these matters are discussed in more detail below. Subsequent chapters of the Access Code deal with other requirements for the provision and pricing of covered network services. For example:

- Chapter 6 addresses price control objectives and requirements;
- Chapter 7 addresses pricing methodology;
- Chapter 9 provides for the regulatory test;
- Chapter 10 addresses dispute resolution;
- Chapter 11 addresses service standards;
- Chapter 12 provides for technical rules; and
- Chapter 13 addresses ring-fencing requirements.

The ERA is the regulator responsible for ensuring that Western Power's proposed access arrangement complies with the Access Code. Western Power's access arrangement was finally approved on 26 April 2007 (Access Arrangement).[176]

173 The ERA interprets the SWIN as being the regulated networks within the SWIS that are owned by Western Power. The SWIN is interconnected with two other (private) networks: Southern Cross' Boulder-Kambalda network and International Power Mitsui's transmission line at Kwinana.

174 See the ERA website at: http://www.era.wa.gov.au/1/264/48/electricity.pm.

175 Access Code, chapter 5, especially clause 5.1.

176 See the ERA website at: http://www.era.wa.gov.au/1/264/48/electricity.pm.

Price control and methodology

As noted above, chapter 6 of the Access Code sets out the objectives and requirements for a price control within an access arrangement. In short, the price control is intended to provide for the service provider (e.g. Western Power) to earn a target level of revenue based on the forward-looking efficient costs of providing covered services, including a reasonable return on investment.[177] The price control mechanism is also intended to provide Western Power with incentives to exceed efficiency, innovation and service quality benchmarks. The target revenue may also be adjusted for unforeseen events and technical rule changes. Provisions dealing with the inclusion of new capital expenditure within the price control are discussed below under network augmentation requirements.

Chapter 7 of the Access Code sets out the objectives of network pricing methodologies and provides that network prices must (amongst other things):

- Fall between incremental and standalone cost;
- Be consistent with Code objectives;
- Avoid price discrimination (other than what can justified by cost differences);
- Avoid price shocks; and
- Reflect prudent discounts where necessary to avoid inefficiency.

Western Power's Access Arrangement goes into more detail on the application of the price control and pricing methodology and explains how Western Power's approach complies with the requirements of the Access Code.

Network planning, connections and augmentation arrangements

<u>Network planning</u>

An overview of Western Power's network planning process is contained in its Access Arrangement Information document.[178] Briefly, Western Power's network development plans are based on regional forecasts of peak demand, assumptions about generation developments and a detailed understanding of conditions on the existing network. These are discussed below:

- Peak demand – Western Power divides the SWIN into the bulk transmission network and a number of load areas. Each load areas is studied in detail at least every two years to ensure it will continue to meet the relevant planning and technical criteria. The focus of these studies is on understanding the most onerous conditions that will affect each network element. These conditions may vary when one is considering the bulk transmission system compared with individual substations or load areas. For example, the bulk transmission system's most onerous peak flows are at the time of system peak, whereas an

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[177] Access Code, chapter 6, especially clause 6.4.

[178] Western Power (2007).

individual substation may have its peak load at a different time to system peak;[179]

- Generation developments – Western Power notes that the timing, location and type of generation projects are the other main drivers of network investment and these are subject to considerable uncertainty, which needs to be managed;[180] and
- Network constraints – Western Power's planning process identifies network constraints over the next 10 years, based on the relevant demand growth and generation development assumptions described above. Western Power notes that it may be possible to avoid network augmentation if demand-side or generation solutions are brought forward in the 'right locations'.[181] Western Power also notes that where network limits are reached, it may be necessary to restrict generator outputs to maintain network safety and security.[182]

Western Power's approach to network planning is informally referred to as embodying an 'unconstrained' network policy.[183] The precise meaning of this term is not defined in any published documents. However, based on correspondence with Western Power staff, it derives from the requirement in the Technical Rules for Western Power to plan, design and construct its power system to ensure that power system stability and performance can be met under the worst credible load and generation patterns and the most critical credible contingency events, without exceeding any component ratings or the allocated power transfer capacity.[184] This, in turn, has led Western Power to only connect new generators where and when the network can accommodate the full output of connected generator(s).[185]

By contrast, the 'constrained' network policy used in the NEM allows generators to be connected even though the transfer capability of the network may not be sufficient to ensure they are dispatched when their offer prices are below the relevant regional reference price.[186]

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179 See Access Arrangement Information, pp.30-31.

180 Access Arrangement Information, p.31.

181 Access Arrangement Information, p.31.

182 See Access Arrangement Information, p.33.

183 See, for example, ERA (2008a), p.7, and Western Power (2008), p.7.

184 Technical Rules 2.3.7.1(a).

185 See Western Power (2008), p.3.

186 See AEMC (2008a), p.vii and pp.7-8,

Network connection and capital contributions

In accordance with the requirements in the Access Code (see above), Western Power's Access Arrangement incorporates a number of policies relating to the process and charging for network connections.

Applications and Queuing Policy

Under this policy, participants are required to submit network access applications containing certain information to Western Power.[187] When submitted, applications take a position in a queue to be assessed by Western Power in the order in which they were received.[188] The ERA recently noted that, due to the large number of applications that Western Power is currently processing, Western Power has informed participants that it cannot commence considering their applications for up to 6 to 12 months.[189] The ERA also acknowledged comments from Western Power that the process of providing a network access offer is necessarily a lengthy one:

> In order to determine the impact of a new connection on the network, Western Power needs to undertake both static network modelling and dynamic network modelling. These steps need to be undertaken sequentially, and Western Power has commented that each set of studies can take two to four months. Following network studies, Western Power needs to undertake an assessment of the cost of the work required to provide a network connection. Western Power has commented that this can take a further two to four months. Depending of the magnitude of work required to provide a network connection, Western Power may then need to proceed through the regulatory test process, and possibly receive approval for network investment from Western Power's board and the Minister. The result is that, from the time that Western Power begins its assessment of an application, it can take up to 18 months to provide a network access offer.[190]

Therefore, the time taken from making an initial network connection application to receiving a network access offer can be well over two years. Furthermore, after an access offer is received, Western Power may need to undertake works to connect the applicant's plant. This will further extend the time taken before a prospective market participant is connected to the SWIN.

[187] Western Power, *Applications and Queuing Policy* (Appendix 1 to Western Power's Access Arrangement), available at: http://www.wpcorp.com.au/mainContent/workingWithPower/NetworkAccessServices/accessArrangement/accessArrangement.html.

[188] Western Power, *Applications and Queuing Policy*, clause 24, especially clause 24.2(a)

[189] ERA (2008a), pp.18-19.

[190] ERA (2008a), p.18.

Capital Contributions Policy

Under this policy, network applicants are required to make capital contributions to Western Power in certain cases where Western Power needs to perform works to provide covered services to the applicant.[191] The policy provides that an applicant is only required to pay a capital contribution in respect of works that do not satisfy the new facilities investment test (NFIT).[192] The amount of contribution is meant to reflect the extent to which the forecast costs of the works allocated to the connection applicant exceed the likely amount of additional revenue gained from providing covered services to the applicant.[193]

Network augmentation requirements

The preceding sections discussed Western Power's approach to network planning and the process and pricing for network connections. This section describes the requirements for:

- Undertaking 'major' augmentations (above $16.2 million for the transmission network and above $5.4 million for the distribution network[194]) – meeting the regulatory test; and
- Recovering the cost of network investments through the price control for covered services – meeting the NFIT.

These requirements are discussed below with reference to the only transmission augmentation proposal submitted by Western Power that has been assessed by the ERA under both the regulatory test and the NFIT – a 330 kV line in the mid-west region of Western Australia.

Regulatory Test

Chapter 9 of the Access Code sets out the obligations and requirements surrounding the regulatory test. The purpose of the regulatory test is to ensure that major augmentations to the covered network are properly assessed and found to maximise net benefits compared with alternative options, *before* the service provider commits to undertaking them. Therefore, a network service provider must not commit to a major augmentation before the ERA determines that the augmentation satisfies the test. 'Net benefit' in this context refers to the present value of net benefits to those who generate, transport and consume

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191 Western Power, *Capital Contributions Policy* (Appendix 3 to Western Power's Access Arrangement), available at: http://www.wpcorp.com.au/mainContent/workingWithPower/NetworkAccessServices/accessArrangement/accessArrangement.html.

192 Western Power, *Capital Contributions Policy,* clause 2; See also clause 2.9 of the Access Code.

193 Western Power, *Capital Contributions Policy,* clause 5.

194 These are 2007 (CPI-adjusted) dollars – see the ERA website at: http://www.era.wa.gov.au/2/537/48/network_augment.pm. These amounts were originally $15 million and $5 million, respectively, in the Access Code.

electricity in the covered and interconnected networks. The assessment against alternative options must take into account the likelihood of those alternatives proceeding.[195]

Service providers may submit a major augmentation proposal regulatory test assessment either within or outside an access arrangement approval process.[196]

Finally, the ERA is empowered to expedite, modify or waive the application of the regulatory test.[197]

In December 2007, the ERA made a determination on the application of the regulatory test to a 330 kV transmission line proposal submitted by Western Power.[198] In that determination, the ERA found that the regulatory test had been satisfied, notwithstanding that Western Power had only:

- Undertaken a cost-effectiveness analysis of the 330 kV line proposal against relevant alternatives; and
- Considered qualitative differences in benefits between the options.[199]

The ERA came to this view because, based on submissions, it found that the potential for market benefits from the options was likely to be greatest for the proposed transmission line option. Therefore, the ERA considered that the quantification of benefits of the different options would only *enhance* the relative net benefits of the proposed transmission line option over the alternatives.[200]

Based on this approach, it would appear that major augmentation proposals that were necessary for reliability reasons would be assessed under the regulatory test using a cost-effectiveness analysis.

New Facilities Investment Test

Sub-chapter 6.2 of the Access Code sets out the provisions dealing with the NFIT. The NFIT may be carried out after or prior to when expenditure on the investment has been incurred, at the service provider's choosing.[201]

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195 Access Code, subchapter 9.1.

196 Access Code, subchapter 9.2.

197 Access Code, subchapter 9.2.

198 ERA (2007a). As noted above, the ERA is required to determine whether any 'major augmentation' satisfies the regulatory test before teh augmentation is committed.

199 ERA (2007a), pp.21-23.

200 ERA (2007a), p.23.

201 Access Code, subchapter 6.3.

The test itself is contained in clause 6.5.2:

> *New facilities investment* may be added to the *capital base* if:
>
> (a) the *new facilities investment* does not exceed the amount that would be invested by a *service provider efficiently minimising costs*, having regard, without limitation, to:
>
> > (i) whether the *new facility* exhibits economies of scale or scope and the increments in which capacity can be added; and
> >
> > (ii) whether the lowest sustainable cost of providing the *covered services* forecast to be sold over a reasonable period may require the installation of a *new facility* with capacity sufficient to meet the forecast sales; and
>
> (b) one or more of the following conditions is satisfied:
>
> > (i) either:
> >
> > > A. the *anticipated incremental revenue* for the *new facility* is expected to at least recover the *new facilities investment*; or
> > >
> > > B. if a *modified test* has been approved under section 6.53 and the *new facilities investment* is below the *test application threshold* – the *modified test* is satisfied; or
> >
> > (ii) the *new facility* provides a *net benefit* in the *covered network* over a reasonable period of time that justifies the approval of higher *reference tariffs*; or
> >
> > (iii) the *new facility* is necessary to maintain the safety or reliability of the *covered network* or its ability to provide contracted *covered services*.

It is worth noting that clause 6.5.2(b)(i) sets out a financial cost-recovery criterion rather than an economic net benefits criterion. In other words, satisfaction of clause 6.5.2(b)(i) does not imply that a proposed investment is net beneficial from the perspective of the market as a whole. This raises the question as to why it is available as a justification for new facilities investment.

On 3 September 2008, the ERA published its final determination on the application of the NFIT to the 330 kV transmission line proposal discussed above in relation to the regulatory test.[202] The ERA found that the forecast new facilities investment of $300 million on the transmission line satisfied the NFIT.[203] However, the ERA's reasoning is confusing in some respects and perhaps reflects the inconsistent frameworks of the regulatory test and the NFIT.

The regulatory test in chapter 9 of the Access Code is based on a net benefits framework, similar to the first 'limb' of the current Regulatory Test in the *National Electricity Rules*.[204]

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202 ERA (2008b).

203 ERA (2008b) p.1.

204 Rule 5.6.5A. The National Electricity Rules are available from the AEMC website at: http://www.aemc.gov.au/rules.php. The AEMC's proposed Regulatory Investment Test for Transmission (RIT-T) (to replace the existing Regulatory Test) also emphasises a net economic benefits approach to transmission augmentation evaluation – see AEMC (2008b).

By contrast to the regulatory test in the Access Code, the NFIT has two separate requirements:

- One requirement is based on the need to efficiently minimise costs (clause 6.5.2(a)); and
- The other requirement broadly based on either:
  - the incremental revenue from the new facility is expected to at least recover its costs (clause 6.5.2(b)(i));
  - the new facility provides a net benefit that justifies higher reference tariffs (clause 6.5.2(b)(ii)); or
  - the new facility is necessary to maintain the safety or reliability of the network or its ability to provide covered services (clause 6.5.2(b)(iii)).

The ERA referred to the various elements of the test as the 'efficiency test' (clause 6.5.2(a)), the 'incremental revenue test' (clause 6.5.2(b)(i)), the 'net benefits test' (clause 6.5.2(b)(ii)) and the 'safety and reliability test' (clause 6.5.2(b)(iii)). The ERA noted that to satisfy the NFIT, the investment must satisfy the efficiency test and one or more of the other tests.[205]

On the efficiency test, the ERA accepted Western Power's submission that the proposed investment's previous satisfaction of the regulatory test was an adequate demonstration that the investment represents an efficient choice of project.[206]

At the same time, however, the ERA questioned the purported net benefits of the investment claimed by Western Power under the net benefits test.[207] However, given the net benefit framework for the regulatory test, it appears odd for the ERA to accept that satisfaction of the regulatory test implies satisfaction of the efficiency test, but not necessarily satisfaction of the net benefits test. To be fair, Western Power did not seek to demonstrate that the proposed 330 kV project would maximise net benefits under the NFIT – Western Power claimed that the project satisfied the NFIT on the basis that it was necessary to reliably serve load growth.[208] Nevertheless, the ERA could have acknowledged that the regulatory test criterion and the net benefits test under the NFIT involve an equivalent form of assessment.

205 ERA (2008b), pp.2-3.

206 ERA (2008b), pp.4-6.

207 ERA (2008b), p.10.

208 ERA (2008b), pp.10-12.

In conclusion, it appears that:

- While the regulatory test is meant to involve an assessment of the net benefits of a proposed project compared to the alternatives, the ERA is likely to interpret this to require only cost-effectiveness analysis where Western Power cannot or does not wish to consider the market benefits of the proposal; and
- The efficiency test within the NFIT will typically be satisfied by implication of a proposal's previous satisfaction of the regulatory test, leaving Western Power only needing to demonstrate a safety or reliability justification to satisfy the NFIT (assuming the incremental revenue test is not satisfied).

2.2 GAS

2.2.1 Introduction

Western Australia has the largest gas reserves in Australia, with substantial offshore gas fields in the Carnarvon, Browse and Bonaparte basins. Western Australia's key gas infrastructure is illustrated in Figure 19.

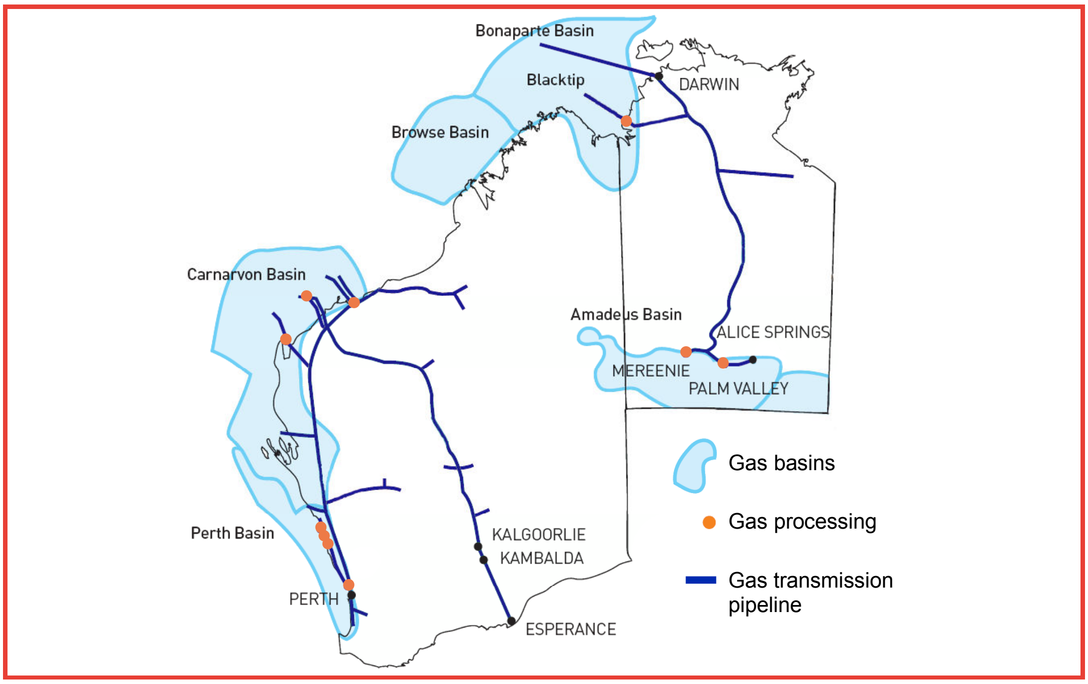

Figure 19: Western Australia and Northern Territory gas infrastructure

Source: AER (2007), p.224.

Despite this abundance of gas, due to the location of Western Australia's gas fields and the way the Western Australian gas market has developed, the domestic gas market remains reliant on a few major sources of supply and pipelines. This has had significant implications for the domestic gas market, with an increasingly tight supply-demand balance over the last few years as a result of the shortage of new volumes available for contract to the domestic market from existing producers. This also exposes Western Australia to the risk that problems with existing infrastructure will substantial reduce the availability of gas, as demonstrated most recently by the June 2008 explosion at Varanus Island.

Outlined in Figure 20 is a breakdown by industry of total primary gas consumption for Western Australia over the period 2004/05 to 2009/10. Consumption over the period 2006/07 to 2009/10 was forecast.

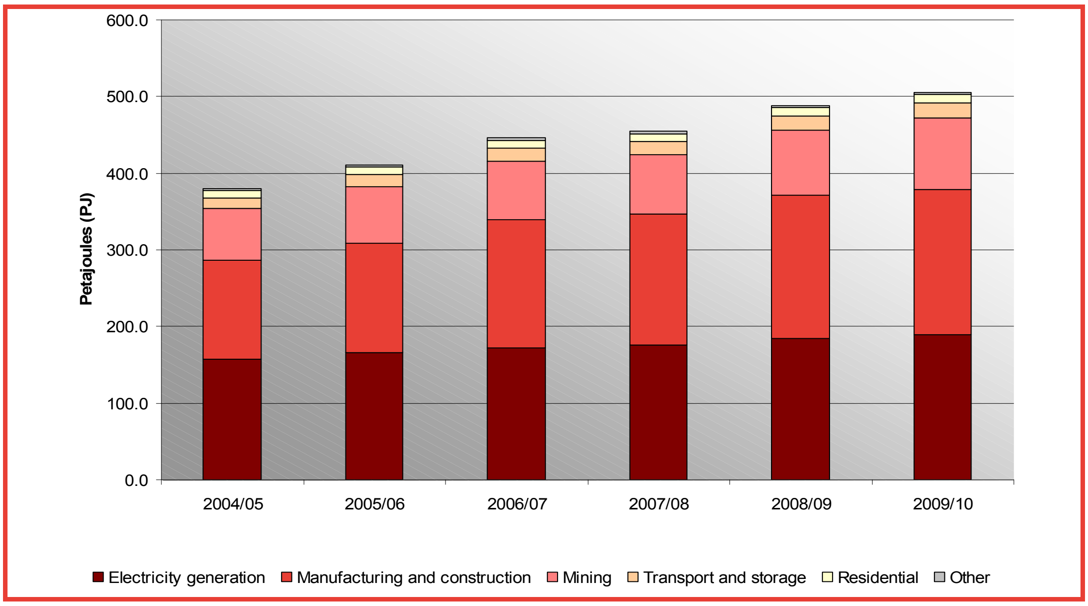

Figure 20: Breakdown of total primary gas consumption by industry

Source: ABARE (2006).

Reform process to date

Reform of gas markets in Western Australia commenced in earnest in the late 1990s. A licensing regime for gas distribution came into effect in late 1999. In 2000 Alinta – the state-owned gas distribution and retail business – was privatised. Subsequently, FRC for gas was introduced in 2004, as discussed in further detail below.

With the legal and technical requirements for retail competition in place, and given the tight supply-demand balance for gas that has emerged over the past few years, policy reform has increasingly focused on upstream gas issues. Several related policy processes have been underway in Western Australia:

- The Western Australian government examined upstream gas supply issues during 2006, with the objective of ensuring that sufficient supplies of competitively priced gas remain available to underpin Western Australia's long term development. The Department of Industry and Resources released an issues paper reviewing possible policy options, following which the then Premier Alan Carpenter announced a policy to secure domestic gas commitments of up to 15 per cent from each LNG export project developed in the State. This reflected a continuation of earlier policy which had, for example, required the North West Shelf Joint Venture (NWSJV) to provide specified volumes of gas to the domestic market.

- The Office of Energy is currently undertaking a review of the gas specification for pipelines in Western Australia and developing an options paper for Government. The current gas specification for the DBNPG is tighter than the relevant Australian Standard. In undertaking this review, the Office of Energy is mindful that the Government's objective is to facilitate industry in developing the least cost solution to bring on stream new gas fields to supply the domestic market. The least cost solution may be to treat the gas so that it meets the existing pipeline specification or to broaden the pipeline specification so that limited treatment of gas is required.

We note that Western Australia does not currently participate in the National Gas Market Bulletin Board established by the Gas Market Leaders Group, although provision has been made for Western Australia and Northern Territory to join in the future. In addition, the Short-Term Trading Market proposed by the Gas Market Leaders Group has only been initially proposed for South Australia and New South Wales.

Gas industry players

Upstream gas suppliers

Upstream gas supply in Western Australia it currently quite concentrated, reflecting the fact that the major gas fields in Western Australia are located offshore and often in relatively deep water, so that development costs are substantial.

The largest supplier of gas to the domestic market is the NWSJV, which consists of Woodside, BP, Chevron, BHP Billiton, Shell and Japan Australia LNG. Gas from the NWSJV that is supplied to the domestic market is jointly marketed by the NWSJV.

Other suppliers from smaller offshore fields around the NWSJV, generally in various joint venture combinations, include Apache, Santos, BHP and Chevron.

Some gas is supplied to the domestic market from gas fields located onshore nearer to Perth, including from Origin and AWE.

Gas transmission

There are three transmission pipelines that supply the majority of gas used domestically in Western Australia:

- The Dampier to Bunbury Natural Gas Pipeline (DBNGP) runs from Dampier to Perth and then on to Bunbury, supplying gas from the Carnarvon basin to users in Perth and coastal regions. The DBNGP is owned by a consortium consisting of DUET, BBI and Alcoa;
- The Goldfields Gas Pipeline runs from a compressor station on the DBNGP to Kalgoorlie in the goldfields (with another pipeline continuing on to Esperence on the south coast). The GGP is majority owned APA Group; and
- The Parmelia pipeline runs from gas fields in the Perth basin to Perth. The Parmelia pipeline is 100 per cent owned by the APA Group.

Access to gas transmission pipelines is regulated by the ERA.

Gas distribution

AlintaGas, owned by BBI, is the largest gas distributor in Western Australia. AlintaGas has distribution licences in the Coastal Supply Area (including Perth), the Great Southern Supply Area and the Esperance-Goldfields Supply Area. AlintaGas delivers gas across three separate distribution networks:

- Mid-west and South-west Gas Distribution System, feeding the greater metropolitan area of Perth, Geraldton and the residential corridor south of Perth to Busselton;
- Kalgoorlie Distribution Network, which services customers in Kalgoorlie-Boulder from gas transported by the Goldfields Gas Transmission Pipeline; and
- Albany Distribution Network, which distributes LPG to Albany from a LPG plant.

Esperence Power Station, Origin and Wesfarmers Kleenheat Gas also hold distribution licences. Access to gas distribution pipelines is regulated by the ERA. Gas distributors must be licensed by the ERA.

Gas retailing

There are currently five gas retailers in Western Australia:

- Alinta Sales is the incumbent retailer and holds a licence to retail gas in the Coastal, Goldfields-Esperance and Great Southern supply areas. AlintaGas Sales retails gas in the areas that are supplied by the AlintaGas Networks distribution system;
- Wesfarmers Kleenheat Gas holds a licence to retail gas in the Coastal and Goldfields-Esperance supply areas. Wesfarmers retails gas in the areas that are supplied by its LPG distribution system: Leinster and Margaret River;
- Worley Parsons Asset Management holds a licence to retail gas in the Goldfields-Esperance supply area. Worley Parsons retails gas in the areas that are supplied by the Esperance Power Station distribution system;
- Synergy holds a licence to retail in the area defined by the SWIS supply area. Up until 1 July 2007, Synergy was prevented from retailing gas under the Gas Market Moratorium. However, changes to the Gas Market Moratorium, which took effect from 1 July 2007, permit Synergy to supply gas to customers using at least 0.18 TJ/a. With the entry of Synergy into the market, Alinta Sales is no longer the monopoly provider in the coastal population centres from Geraldton to Busselton and in the Kalgoorlie-Boulder area; and
- Origin Energy was recently granted a licence to retail in Kalbarri.

Gas retailers to small customers must be licensed by the ERA. REMCo is the retail market administrator for the gas market in Western Australia.

2.2.2 Wholesale arrangements

Sources of gas supply in Western Australia

Domestic gas supplies in Western Australia come from two basins: the Perth basin and the Carnarvon basin.

The first commercial gas discoveries in Western Australia were in the Perth basin, north of Perth. The Dongara field was commissioned in 1971, in parallel with the commission of the 416 km Parmelia pipeline from Dongara to Perth. Other fields were subsequently developed. Despite the subsequent discovery of much larger reserves in Western Australia, gas from these fields continues to be supplied to industrial customers in and around Perth. The largest producing fields in the Perth basin – Dongara, Beharra Springs and Woodada – are generally considered to be close to exhausted. However, alongside the recent increases in domestic gas prices in Western Australia, there has been a renewed focus on exploration in the Perth basin.

Just as first gas was made available from the Perth basin, major gas fields were discovered in the Carnarvon basin. These discoveries led to the development of the NWSJV and the commercialisation of these gas reserves. First gas was delivered from the NWSJV in 1984 through the newly constructed Dampier to Bunbury Natural Gas Pipeline (DBNGP) to Perth and surrounding areas. The commercial development of the NWSJV was underwritten by long-term supply contracts with the State Energy Commission of Western Australia (SECWA) and Alcoa. Gas continues to be supplied from the NWSJV to the domestic market, although far greater volumes of gas are now exported to international markets in the form of LNG.

Since the development of the NWSJV, a number of other significant gas fields have been discovered in the Carnarvon basin. Several of these have commenced supplying the domestic Western Australian market:

- The Harriet field, operated by Apache Energy, commenced production in 1992. Processing facilities were located on nearby Varanus Island, which was connected to the DBNGP and, subsequently, the Goldfields Gas Pipeline.
- The East Spar field, operated by Apache Energy, commenced production in 1993. Gas from the field is also processed at Varanus Island.
- The John Brookes field, operated by Apache Energy, commenced production in 2005. Gas from the field is also processed at Varanus Island.

Around the time that gas fields were being discovered and assessed around Varanus Island, the State Government was seeking interest in the construction of a gas pipeline to the goldfields. A contract was eventually awarded and the Goldfields Gas Pipeline was commissioned in 1996. The development of the Goldfields Gas Pipeline was also crucial to the development and growth of gas production around Varanus Island. With the development of the pipeline, the East Spar field and Harriet fields were able to secure supply contracts with numerous users along the Goldfields Gas Pipeline.

A number of other significant gas fields in the Carnarvon basin are yet to enter production:

- The Reindeer field, located near the NWSJV, is currently under development by Apache and Santos. A gas processing facility is being constructed at Devil Creek for supply of gas to the DBNGP. First gas is expected to be delivered in 2010;
- The Gorgon field is a major gas field located south-west of the NWSJV, near Varanus Island. The field has the reserves to support both domestic gas supplies and LNG exports. The development of the project is currently being assessed by the owners of the field – Chevron, Shell and ExxonMobil. It is likely that a processing facility would be located on Barrow Island, but a decision on gas deliveries to the mainland has not yet been made. Proposals for the establishment of a domestic gas project are to be made to the Minister for State Development by 31 December 2010;
- The Pluto field is a major gas field located between south-west of the NWSJV and north of Varanus Island. The field has sufficient gas reserves to support LNG export. An LNG facility is currently being developed on the Burrup peninsula, with first gas expected to be delivered for export in 2010. The facility on the Burrup peninsula has been designed to support future growth in LNG exports as well as facilities for domestic gas supply; and
- The Macedon field is located south-west of both the NWSJV and Varanus Island, near Thevenard Island. Gas from the field could potentially supply up to 20 per cent of Western Australia's gas demand, but the field is currently unable to supply the domestic market because the gas from the field does not meet the specifications for the DBNGP. The Office of Energy has recently commenced developing an options paper for Government on whether the gas specification on gas pipelines should be broadened by regulation.

Despite the fact that Western Australia has by far the largest gas reserves of any state in Australia, domestic gas supply has been tight over the last two years. Even before the recent explosion at Varanus Island, Lyndon Rowe, Chairman of the Economic Regulation Authority, had reported that gas supply contracts were difficult to secure and that long-term gas contracts have not been available.[209] This reflected a significant change from the historical situation, which was characterised by substantial long-term contracts up to 20-25 years.

This tight supply of gas has been reflected in gas prices. Historically, Western Australia has benefited from relatively low gas prices, in the order of \$2/GJ to \$2.50/GJ undelivered. Contract prices were observed to increase during 2006 and 2007, with the ERA reporting prices in the range of \$5.50/GJ to \$6/GJ by 2007.[210] Some reports indicate that prices have increased further since then.[211]

[209] Lyndon Rowe, *Gas Issues in Western Australia*, Presentation to the Australian Institute of Energy, 13 June 2007.

[210] Lyndon Rowe, *Gas Issues in Western Australia*, Presentation to the Australian Institute of Energy, 13 June 2007.

Gas use in Western Australia

Reflecting Western Australia's large gas reserves, domestic gas use in Western Australia is the highest of any state in Australia. According to data collected by ABARE, annual domestic gas use in Western Australia was close to 475 PJ per annum in 2006/07 (up from around 400 PJ per annum in 2005/06).

The majority of gas in Western Australia is used for the purposes of manufacturing, mining or electricity generation. Only very small amounts of the State's domestic gas are used for residential or commercial purposes.

Gas used for the purposes of manufacturing or electricity generation is used predominantly in Perth and the coastal regions of Western Australia. Major users include Alcoa, (which operates alumina refineries in Kwinana, Pinjarra and Wagerup), BHP (which operates an alumina refinery at Worsley), Verve Energy (which operates a number of gas-fired generation plant in the SWIS) and Alinta (which operates gas-fired generation plant and retails gas to small and large users).

Gas used for the purposes of mining is used predominantly in the goldfields. Major users include WMC's nickel operations, BHP's iron ore operations, Anaconda's nickel operations and Newmont's gold mines.

Wholesale market arrangements

There is currently no formal wholesale gas market in Western Australia. The majority of gas is supplied under long-term agreements between gas suppliers and gas users. However, there are currently two facilities for the short-term trading of gas in Western Australia: trading capacity on the DBNGP and the gas bulletin board.

<u>Trading capacity on the DBNGP</u>

Gas is delivered from the Carnarvon basin to Perth and other coastal areas along the DBNGP. In the short-term, it has been reported that access to capacity on the DBNGP can be a problem. While the pipeline has been regularly expanded over recent years – through the addition of compression and through looping – expansions tend only to occur when underwritten by a long-term contract.

Access to the DBNGP is regulated under the National Gas Code by the Economic Regulation Authority. Under the access arrangement for the DBNGP there is specified both a nominations process and a trade or transfer process:

- According to the nominations process, the pipeline operator is required to regularly specify the amount of capacity available to be nominated on the pipeline by shippers. Shippers must specify their nominations for reserved capacity for a gas day by no later than 2 PM on the previous day. The pipeline operator must notify the shippers of daily nominations for the gas day by no

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[211] See, for example, David Upton, *Gas prices ignite*, Petroleum, April 2008; Santos, *Santos secures Moly Metals gas supply contract*, Media Release, 8 October 2008.

later than 4 PM on the previous day. In the event that the pipeline operator cannot meet all shippers' nominations for firm capacity, the access regime specifies a curtailment process.

In the event that there is capacity available after all nominations for reserved capacity have been allocated, this spot capacity is available for purchase under a spot transaction. Shippers must bid for spot capacity for a gas day by no later than 3 PM on the previous day. The pipeline operator must allocate any available spot capacity to shippers on the basis of prices bid for the spot capacity, and notify shippers of spot capacity allocations for a gas day by no later than 4 PM on the previous day. In either case, because the timing of the nominations process, shippers do not have certainty as the availability of either firm capacity or spot capacity until 4 PM on the day before the relevant day.

- According to the process for trading or transferring contracted capacity on the pipeline, if a shipper wants to trade or transfer contracted capacity, the operator of the DBNGP is required to notify other shippers of contracted capacity that is offered for trade. If a counterparty is found, and as long as the conditions for trade or transfer set out in the access arrangement are met,[212] this capacity can then be traded or transferred.

The access arrangement for the DBNGP provides some facility for trade of capacity on the pipeline, but does not deal with upstream gas supplies. Typically, short-term trade in upstream gas supplies has occurred informally between major users in Western Australia. However, following the Varanus Island explosion, and the resulting shortage of gas supplies for the domestic market, a more formal gas bulletin board was put in place by the IMO (separate from the one that recently commenced operation in the eastern states).

The Gas Bulletin Board

The Gas Bulletin Board, administered by the IMO, provides a matching service by which buyers and sellers whose bids/offers overlapped were introduced to each other. The Gas Bulletin Board does not play any role in the determination contract terms, but merely acts as an intermediary between buyers and sellers. Participation in the Gas Bulletin Board is voluntary. Initially, during the height of the gas shortage, a number of bids and offers were received on the Gas Bulletin Board for each trading day. Since the gas supply situation has improved, however, submissions to the Gas Bulletin Board have ceased.

[212] Conditions for the trade or transfer of capacity set out in the access arrangement include that the replacement shipper must either have a contract with the pipeline operator or must have satisfied the pipeline operator or its creditworthiness.

2.2.3 Retail arrangements

Retail competition

FRC was introduced in the gas market in Western Australia in May 2004, meaning that all gas customers in Western Australia are able to choose their supplier. However, while the introduction of FRC means that the legal and technical requirements for retail competition are in place it does not necessarily follow that new retailers will enter the market. Indeed, competition in the retail gas market has been slow to develop.

While there are currently five gas retailers licensed in Western Australia, Alinta Sales still dominates the retail market in Western Australia. According to data from the ERA's latest report on gas distribution and trading, Alinta Sales accounts for over 99.8% of all small use residential connections and 99.9% of all other (non-residential) connections in the State.[213]

Tariff regulation

As part of the privatisation of AlintaGas in 2000, caps on gas tariffs for households and small business customers were introduced. The tariff caps introduced in 2000 were intended to provide a "safety net" for customers, allowing for a sufficient margin for gas retailers, accounting for the risks faced by those retailers. It was originally intended that these tariff caps would cease to apply to small business customers as of 1 July 2002 and that residential tariffs would escalate at CPI+2% each year from this time.

Prior to the introduction of gas FRC in Western Australia in 2004, the Tariff Regulations were amended to reinstate tariff caps for small business, and to make the annual tariff cap increase at CPI each year. The amended Tariff Regulations cap the retail price of gas to small use customers (households and small business customers using less than 1 TJ of gas per annum) in the areas covered by the Tariff Regulations. This includes the Mid-West/South West (including the Perth metropolitan area), Albany, and Kalgoorlie-Boulder areas.

In their current form, the Tariff Regulations allow retailers to set their tariffs for new small use customers as they wish, so long as they offer at least one form of tariff under the tariff cap arrangements.

The Minister for Energy is currently conducting the Gas Tariffs Review to assess the tariff cap arrangements in Western Australia. The Office of Energy is responsible for completing the Review and preparing recommendations for consideration by the Minister. As part of this review, the Office of Energy is considering the appropriate structure and level of the tariff caps. As an interim step in the Gas Tariffs Review, the tariff cap was increased from 1 July 2008 by between 5.4 per cent and 16.5 per cent. A more detailed review will be undertaken for implementation from 2009/10.

[213] ERA. *2006/07 Annual Performance Report: Gas Distribution and Trading Licences*, October 2007.

3 Northern Territory

3.1 ELECTRICITY

3.1.1 Introduction

The Northern Territory's electricity industry is small by eastern States' standards, reflecting its population of around 200,000. The Territory's key electricity infrastructure is illustrated in Figure 1. The Northern Territory consumed a total of 1,795GWh in 2007/08, or roughly 0.9 per cent of the NEM's annual consumption and 11 per cent of that consumed in the SWIS.[214] The Territory's electricity market is comprised of three relatively small, regulated systems[215]:

- Darwin to Katherine – With a combined regulated and unregulated capacity of 367MW and 5,360km of power lines;
- Alice Springs – With a combined regulated and unregulated capacity of 91MW and 1,068km of power lines; and
- Tennant Creek – With a combined regulated and unregulated capacity of 22MW and 477km of power lines.

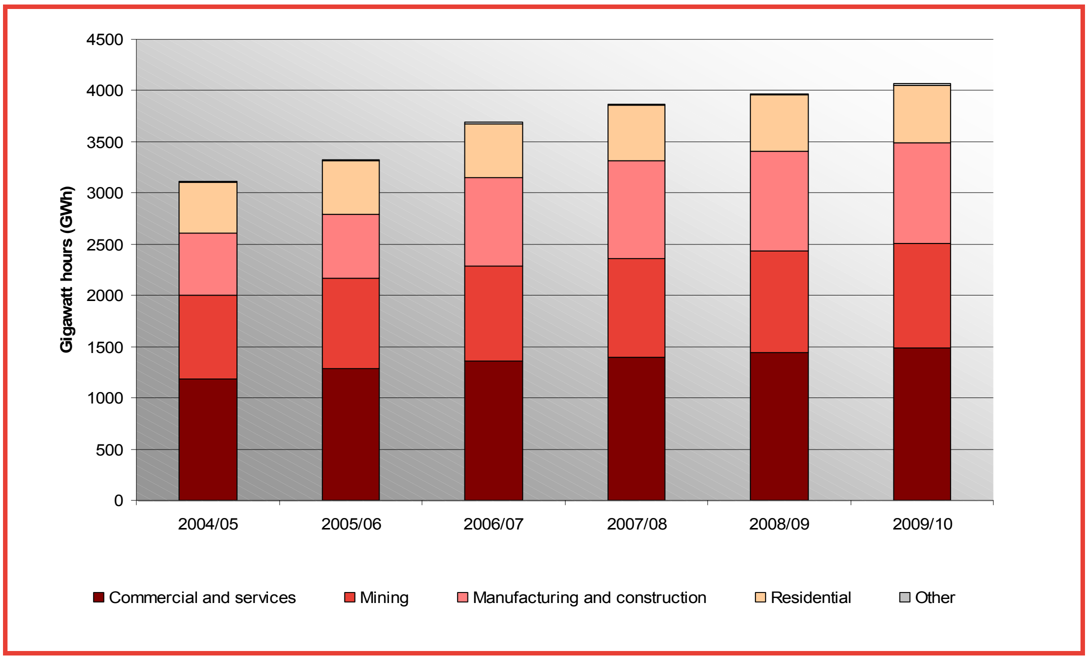

Figure 21: Breakdown of total final electricity consumption by industry

Source: ABARE (2006).

[214] NT Government (2008), p.6.

[215] Utilities Commission (2008), p.1.

Outlined in Figure 21 is a breakdown by industry of total final electricity consumption for the Northern Territory over the period 2004/05 to 2009/10. Consumption over the period 2006/07 to 2009/10 was forecast.

Over 99% of energy in the Northern Territory's regulated systems is generated using gas-fired plant.[216] Due to a lack of climatic suitability, the Territory has virtually no wind generation. However, both photovoltaic and thermal solar generation is used on a small scale in remote areas.

Regulatory arrangements

Regulation of the Territory's electricity supply and electricity network industries is the responsibility of the Utilities Commission. The Utilities Commission was established under the *Utilities Commission Act* in March 2000. The *Utilities Commission Act* defines the Commission's overall functions and powers. However, the specific responsibilities of the Utilities Commission with respect to a particular industry are assigned to the Utilities Commission by provisions in the relevant industry regulation Acts. The relevant Acts applying to the electricity supply industry are:

- *Electricity Reform Act*; and
- *Electricity Networks (Third Party Access) Act.*

In particular, the Territory's electricity network industry is declared to be a regulated industry by the *Electricity Networks (Third Party Access) Act*, while the Territory's electricity supply industry is declared to be a regulated industry under the *Electricity Reform Act.* As such, both of these industries fall under the jurisdiction of the Utilities Commission.

The Utilities Commission's broad mandate is to ensure the promotion and safeguard of competition and fair and efficient market conduct. In the absence of a competitive market, the Utilities Commission aims to simulate the conditions of competitive conduct by preventing the misuse of monopoly power in the regulated markets for which it is responsible.[217]

Reform to date

Starting in early 2000, the Government began introduced measures to open the Territory's electricity markets to competition – this involved:

- Corporatising the Power and Water Corporation (PWC) and ring-fencing its generation, system control, network and retail activities. PWC is currently the monopoly provider of public electricity and water in the Territory;
- Allowing new suppliers to enter the market;
- Establishing an independent regulator – the Utilities Commission; and

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[216] Utilities Commission (2007), p.25.

[217] http://www.utilicom.nt.gov.au/

- Introducing a regulated access regime for transmission and distribution networks. The Federal Government certified this regime as effective under the *Trade Practices Act* in 2002.

Despite these reforms, competition in the Territory's electricity markets has failed to materialise, and to date almost all generation, network, and retail services across the Territory are provided by the government-owned PWC.

The one exception to this was the brief entry into the market of NT Power in 2000. However, NT Power withdrew from the market in September 2002 citing an inability to source ongoing gas supplies for electricity generation.[218]

3.1.2 Wholesale market arrangements

As noted above, the Northern Territory's wholesale electricity market is comprised of three relatively small, regulated systems – the largest being the Darwin to Katherine system with a capacity of 367MW.

The Territory almost exclusively uses gas-fired plants to generate public electricity, sourcing gas mainly from the Amadeus Basin in Central Australia. Given the scale of the market, it is not considered feasible to establish a wholesale electricity spot market. Rather, the Territory uses a 'bilateral contracting system', in which generators are responsible for dispatching into the system the power their customers require.

The industry is dominated by a government-owned corporation, PWC, which owns the transmission and distribution networks and is responsible for power system control. There are six IPPs in the resource and processing sector that generate their own requirements – some of these participants also generate electricity for the market under contract with PWC.

PWC is responsible for providing electricity generation and networks services in remote and regional communities. In some cases, PWC uses privately-owned electricity networks and purchases wholesale electricity from IPPs, usually from mining companies.[219] PWC also relies on renewable generation, mainly in the form of solar technology, to supply remote areas.

Average negotiated generation contract prices in the Territory appear to have increased in both nominal and real terms over the last five years. Several possible explanations could lie behind this observation – the small scale of the Territory market, the lack of effective competition and a large reliance on higher-cost gas are all likely to be driving this increase. In addition, the NT Government is of the view that the Territory's regulatory framework does not provide sufficient incentives for the Territory's electricity industry to strive to identify efficiencies over time. To the extent that is the case, it may also have been a factor contributing to higher prices.[220]

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[218] AER (2007), p.213.

[219] NT Government (2008), p.7.

[220] NT Government (2008), p.17.

Following NT Power's withdrawal from the Territory's electricity market in September 2002, and recognising the pricing implications that could arise from monopoly service provision, the Northern Territory Government approved a process of price oversight of PWC's generation business by the Utilities Commission for as long as competition, or the tangible threat of competition, did not arise. The purpose of such regulation was to ensure that the wholesale energy prices paid by contestable customers were similar to what would have occurred in a competitive environment, and that PWC's generation business recovered over time no more than the reasonable long-run cost of supplying wholesale energy to the market.

In April 2005, the Utilities Commission undertook a review of the generation component of electricity prices paid by contestable customers, covering the financial years 2002/03 and 2003/04. The Utilities Commission found that during 2002/03 and 2003/04, Power and Water's wholesale electricity generation prices were generally consistent with the Utilities Commission's estimates of the reasonable costs associated with generation in those years.[221]

3.1.3 Retail market arrangements

In 2000 the Territory Government commenced a phased introduction of retail contestability, originally scheduled for completion in April 2005. The initial schedule proposed is re-produced in Table 6.

Date for Introduction	Customer Load Level (Annual)
1 April 2000	Greater than 4GWh
1 October 2000	3GWh – 4GWh
1 April 2001	2GWh – 3GWh
1 April 2002	750MWh – 2GWh

Table 6: Retail contestability timetable

Source: Utilities Commission (1999)

In light of NT Power's exit from the market in 2002 and PWC resuming its position as the monopoly retail provider, the Government suspended its retail contestability timetable in January 2003. This has effectively halted contestability at the 750 MWh per year threshold. The introduction of FRC is currently scheduled for April 2010.[222]

[221] http://www.nt.gov.au/ntt/utilicom/electricity/wholesale_generation_pricing.shtml

[222] AER (2007). p.213.

3.2 GAS

3.2.1 Introduction

Historically, over 90 percent of natural gas used in the Territory is for electricity generation. Industrial customers use most of the remainder, with a small quantity being reticulated to commercial and residential users in Alice Springs and Darwin.

Outlined in Figure 21 is a breakdown by industry of total primary gas consumption for the Northern Territory over the period 2004/05 to 2009/10. Consumption over the period 2006/07 to 2009/10 was forecast.

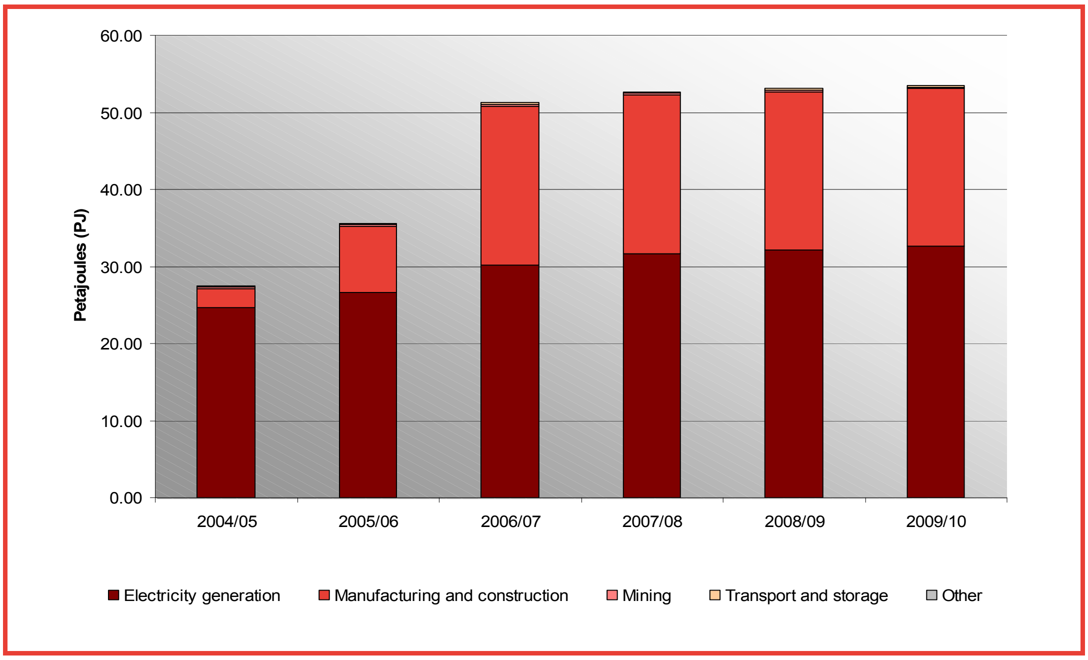

Figure 22: Breakdown of total primary gas consumption by industry

Source: ABARE (2006).

More recently, increasing quantities of gas have been exported as LNG. The three key gas reserves in the Territory are the Amadeus, Browse and Bonaparte basins. Wholesale gas market arrangements in the Territory, like in most states, tend to be dominated by confidential, long-term take-or-pay contracts. The National Gas Market Bulletin Board, an initiative of the Gas Market Leaders Group, does not currently operate in the Northern Territory. The Northern Territory's key gas infrastructure is illustrated in Figure 19.

3.2.2 Wholesale market arrangements

Gas reserves

As noted above the Northern Territory has three key gas reserves – the Amadeus, Browse and Bonaparte basins. Each is briefly discussed below.

The Amadeus basin

Gas for use in the Northern Territory is supplied from the Palm Valley and Mereenie fields in the Amadeus Basin. These fields are controlled by joint ventures involving Magellan and Santos. Roughly 218 petajoules of gas remains in the Amadeus Basin. The basin is currently producing around 20 petajoules of gas a year, which is sufficient to meet all current demand for gas in the Northern Territory. The basin is in decline, however, so that gas for electricity production will soon be supplemented by supplies from the Blacktip field in the Bonaparte basin.

The Bonaparte–Timor Sea basin

The Bonaparte basin is estimated to contain a contingent resource of about 19,500 petajoules of gas. In addition the basin is estimated to contain about 4,464 petajoules of 2P gas reserves. Australia's share of this reserve is 1,687 petajoules, with the rest belonging to Timor Leste. Bayu-Undan (located in the Australia-Timor Leste Joint Development Area) is the only area in the basin producing gas at this time. Development of the basin centres on LNG production for export. The first shipment of LNG was in February 2006 and overall production for the year to December 2006 was around 123 petajoules. The Blacktip field is currently being developed to supply domestic gas to the Northern Territory, with the first gas expected to flow from January 2009.

The Browse basin

To the south-west of the Bonaparte basin lies the Browse basin. The Browse basin contains significant natural gas resources, which are currently subject to development studies for LNG export.

Gas transmission

Northern Territory's gas transmission and distribution networks are regulated by the Australian Energy Regulator (AER). The Territory's principle transmission pipeline, the Amadeus Basin – Darwin System, is majority-owned by the APA Group[223] and is operated by NT Gas. The Amadeus Basin – Darwin pipeline is covered under the Gas Access Code, which has recently been superseded by the National Gas Law and Rules. Approximately 94%[224] of gas transported on this pipeline is used in the generation of electricity, with the remaining capacity being reticulated to industrial and residential users in Darwin and Alice Springs.

In addition to the covered Amadeus Basin – Darwin pipeline, the Territory has two uncovered pipelines:

- Palm Valley – Alice Springs is a 146km pipeline owned by Envestra; and

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223 The APA Group comprises Australian Pipeline Trust and APT Investment Trust.

224 http://www.pipelinetrust.com.au/4/4-4.html

- Bayu-Undan – Darwin is an off-shore pipeline from the Bayu-Undan field in the Bonaparte basin to an LNG terminal near Darwin. This pipeline is operated by ConocoPhillips and its supply is currently used exclusively for export LNG.

In addition, the APA Group has proposed to construct a pipeline from the Blacktip Gas Plant, which is connected to the offshore Blacktip field in the Bonaparte basin, to a connection point with the existing Amadeus Basin – Darwin pipeline at Ban Ban springs. Gas supplied from this pipeline is expected by 1 January 2009.[225]

3.2.3 Retail market arrangements

Introduction

As noted above, the overwhelming majority of 'covered' gas in the Northern Territory is used in the generation of electricity, with the balance being reticulated to industrial users in Alice Springs and Darwin. As such the Territory has a small residential retail base.

There are two primary gas retailers in the Territory – Envestra and NT Gas. Envestra retails gas in the Alice Springs area while NT Gas reticulates small quantities to commercial and industrial customers in Darwin's industrial areas.

The Territory's retail gas market is currently fairly tight – all available gas is currently contracted to 2009[226]. While the lack of gas availability has precluded entry into the retail gas and wholesale electricity market in the Territory, the supply of gas from the Blacktip field in the Bonaparte basin (due to being flowing in January 2009) is expected to ease supply-side restrictions and promote entry into these markets.

Regulatory arrangements

The Territory Government introduced FRC into the Territory's gas market in October 2001. The introduction of FRC has allowed customers to enter into contracts with licensed sellers of their choice for gas supply. As part of FRC's introduction in other states, most Governments appointed a local retailer to ensure that small gas customers in nominated geographical areas were supplied at regulated tariffs. This provision ensured that a 'default' option existed for customers who had not entered into market contracts with other suppliers. Due in part to its lack of significant residential gas customers the Northern Territory did not follow this model and has never regulated retail gas services.[227]

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[225] http://www.pipelinetrust.com.au/4/4-8set.html

[226] AER (2007), p.288.

[227] AER (2007), p.291.

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Appendix B: Numerical STEM example

INTRODUCTION

- Consider two Market Participants: 1 Market Customer and 1 Market Generator/Customer:
  - The Market Customer has a Net Bilateral Position (NBP) of -40 MWh (i.e. they are contracted to *buy* 40MWh); and
  - The Market Generator/Customer has an NBP of 20 MWh (i.e. they are contracted to *sell* 20 MWh)[228].
- The Market Customer submits only a Demand Schedule to the IMO (they are not contracted to supply any energy) while the Market Generator/Customer submits both a Supply and Demand Schedule to the IMO (they are contracted to both supply and purchase energy).
- Finally, assume the Maximum STEM Price is $200/MWh while the Minimum STEM Price is -$100/MWh.

GENERATING STEM BIDS AND OFFERS

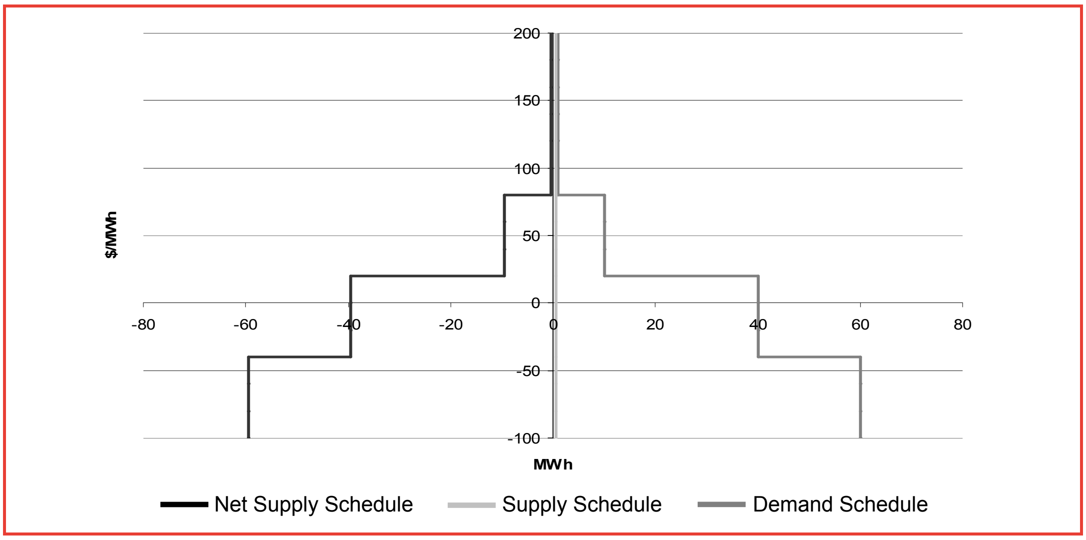
3.2.4 Market Customer

- The Market Customer submits the following Supply Schedule:
  - 0 MWh at $0/MWh.
- The Market Customer submits the following Demand Schedule:
  - 10 MWh at $80/MWh;
  - An additional 30 MWh at $20/MWh; and
  - An additional 20 MWh at -$40/MWh.
- Thus the Market Customer submits a Demand Schedule for a total of 60MWh to the IMO.
- Using these Supply and Demand Schedules and the Market Customer's NBP of -40 MWh, the IMO constructs the Market Customer's Bid/Offer Curve. This is done by:

  Stage (i): Forming the Market Customer's Net Supply Schedule

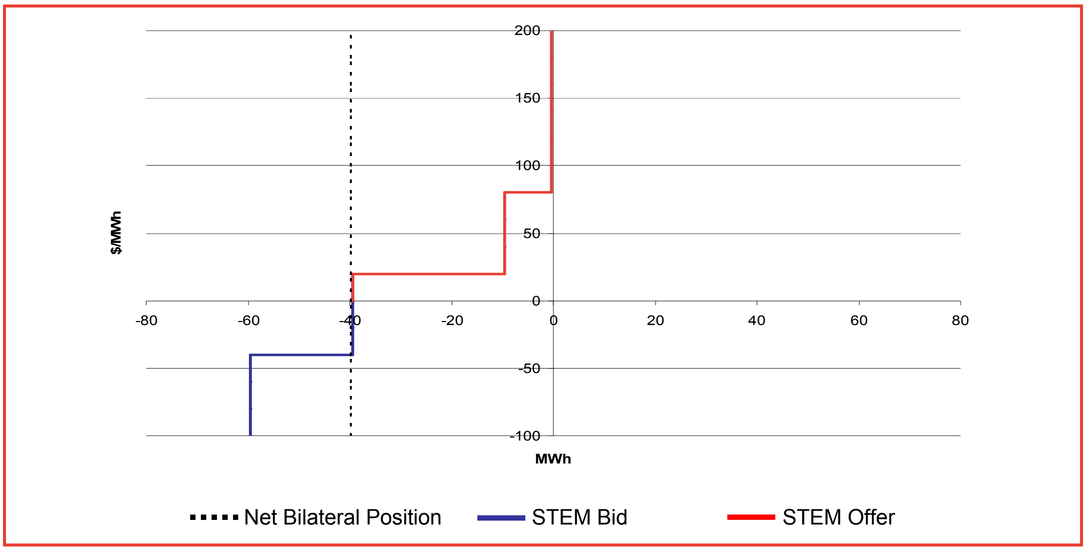
  The Market Customer's Demand Schedule is added[1] to the Market Customer's Supply Schedule to produce the Market Customer's *Net* Supply Schedule.

[228] By convention demand is treated as negative and supply is treated as positive. Hence adding demand and supply produces net supply.



Stage (ii): Forming the Market Customer's Bid/Offer Curve

Quantities on the Market Customer's Net Supply Schedule *above* the Market Customer's NBP are defined as offers, while quantities on the Market Customer's Net Supply Schedule *below* the Market Customer's NBP are defined as bids:



- This Bid/Offer Curve implies that the Market Customer is willing to offer in the STEM:
  - 30 MWh at $20/MWh; and
  - An additional 10 MWh at $80/MWh.

  Thus the Market Customer's cumulative STEM offer is 40MWh.
- This Bid/Offer Curve implies that the Market Customer is willing to bid in the STEM:
  - 20 MWh at -$40/MWh.

Appendix B: Numerical STEM example

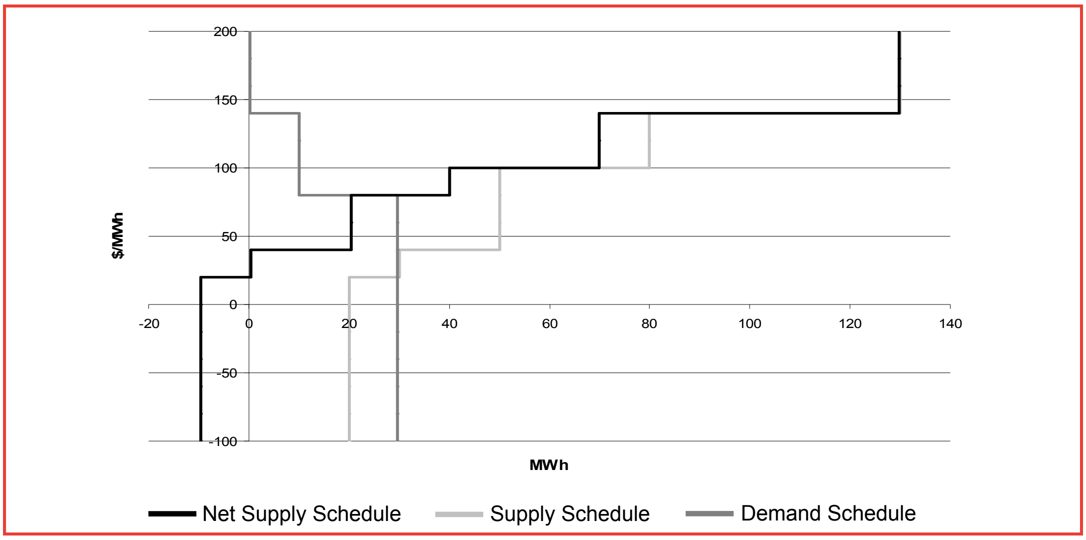
Thus the Market Customer's cumulative STEM bid is 20MWh.

3.2.5 Market Generator/Customer

- The Market Generator/Customer submits the following Supply Schedule:
  - 10 MWh at $20/MWh;
  - An additional 20 MWh at $40/MWh;
  - An additional 30 MWh at $100/MWh; and
  - An additional 50 MWh a4 $140/MWh.
- The Market Generator/Customer submits the following Demand Schedule:
  - 10 MWh at $140/MWh;
  - An additional 20MWh at $80/MWh
- Thus the Market Generator/Customer submits a Supply Schedule for a total of 110MWh and a Demand Schedule for a total of 30MWh to the IMO.
- Using these Supply and Demand Schedules and the Market Generator/Customer's NBP of 20 MWh, the IMO constructs the Market Generator/Customer's Bid/Offer Curve. This is done by:

Stage (i): Forming the Market Generator/Customer's Net Supply Schedule

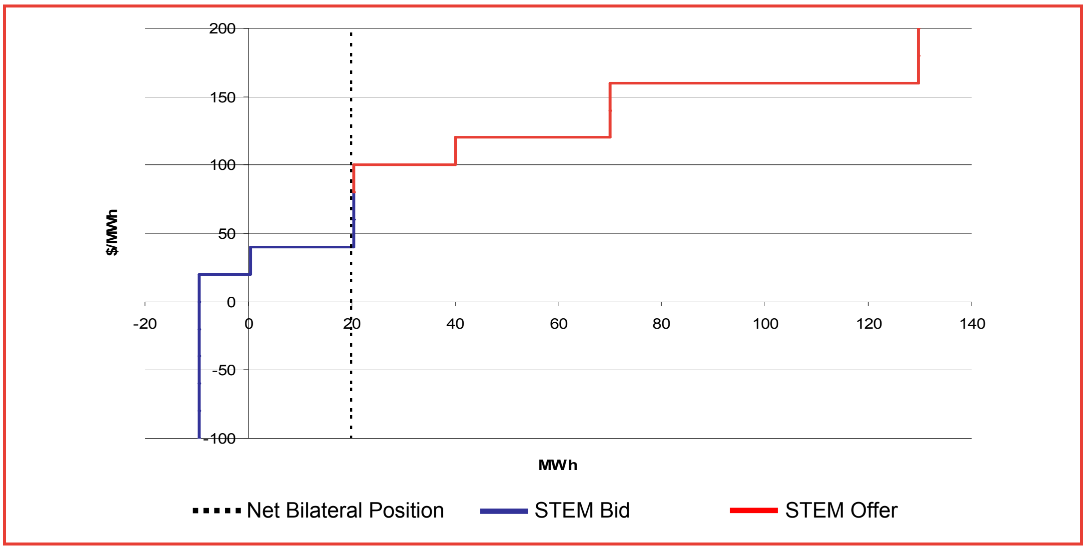
The Market Generator/Customer's Demand Schedule is added[1] to the Market Generator/Customer's Supply Schedule to produce the Market Generator/Customer's *Net* Supply Schedule:



Stage (ii): Forming the Market Generator/Customer's Bid/Offer Curve

Quantities on the Market Generator/Customer's Net Supply Schedule *above* the Market Generator/Customer's NBP are defined as offers, while quantities on the

Market Generator/Customer's Net Supply Schedule *below* the Market Generator/Customer's NBP are defined as bids:



- This Bid/Offer Curve implies that the Market Generator/Customer is willing to offer in the STEM:
  - 20 MWh at $100/MWh;
  - An additional 30 MWh at $120/MWh; and
  - An additional 60MWh at $160/MWh.

  Thus the Market Generator/Customer's cumulative STEM offer is 110MWh.
- This Bid/Offer Curve implies that the Market Generator/Customer is willing to bid in the STEM:
  - 20 MWh at $40/MWh; and
  - An additional 10 MWh at $20/MWh.

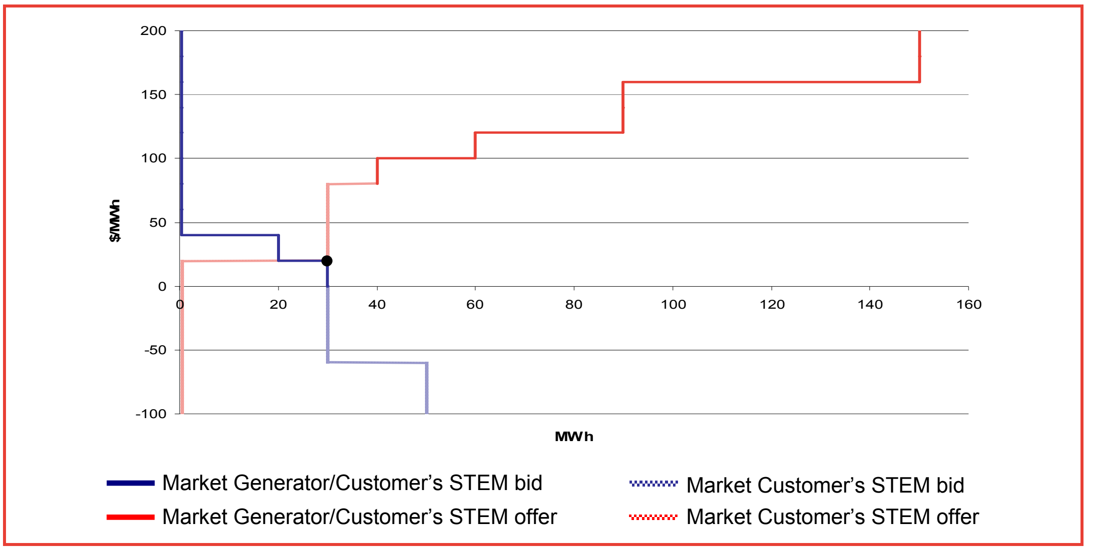
  Thus the Market Generator/Customer's cumulative STEM bid is 30MWh.

GENERATING THE STEM PRICE

- The IMO generates aggregate STEM bid and offer curves by summing and ordering the cumulative bids and offers of each Market Participant; and
- The IMO determines the STEM Price by solving for the price-quantity pair for which aggregate STEM offers (supply) equal aggregate STEM bids (demand).
- In this example the STEM Price is $20/MWh and quantity traded in the STEM is between 20MWh and 30MWh[229].

[229] Assume for simplicity that the quantity traded is 30MWh.

- In this example, the Market Customer sells the Market Generator/Customer 30MWh in the STEM:
  - At $20/MWh, the Market Customer offers 30MWh in the STEM, and
  - At $20/MWh the Market Generator/Customer is willing to purchase 30MWh in the STEM (20 MWh at $40/MWh and an additional 10 MWh at $20/MWh for a total of 30MWh).



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