Government of Western Australia
Department of Finance
Public Utilities Office

Electricity Market Review

Discussion Paper

Electricity Market Review Steering Committee
25 July 2014

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Executive Summary

Regulated retail electricity prices in Western Australia have increased substantially between 2006-07 and 2013-14. In addition, taxpayer funding of the industry by way of operating subsidies is now at record levels. Annual operating subsidies (including Horizon Power) are forecast to grow to $600 million within the year. While this is partly because of increases in costs associated with the generation and network elements of the energy supply chain, these costs alone do not adequately explain the tariff increases that have occurred.

This Discussion Paper is aimed at eliciting feedback from industry participants about the structure and performance of the Wholesale Electricity Market (the WEM), the underlying reasons for cost increases and the options available to address these problems.

The questions posed in the paper reflect the concerns of the Electricity Market Review Steering Committee. The most basic question to which we seek an answer can be framed as follows: is the electricity industry in the south west of Western Australia working efficiently in the best interests of customers? In order to answer this wide ranging question we have posed several specific questions in chapter 3 of the paper. These are:

- Why is the cost of supplying electricity to retail customers so high that it requires a significant taxpayer subsidy to keep tariffs at levels comparable to those in other Australian states?
- Could the current industry structure, that is the number of separate generators and retailers, result in a competitive market under any market mechanism?
- Why can high volumes of generation capacity be added each year, with the costs passed through to customers, when there is clearly no requirement for it?
- Are network costs reasonable and does the network access code enable long term efficient entry and exit of plant?
- What does the current primary fuel situation indicate for the availability and price of fuel for future generation?
- Is the current trajectory of electricity costs and taxpayer subsidies sustainable?

The paper presents comparisons of generation costs with other Australian states which, while taking into account differences in underlying fuel costs and the size and conversion efficiency of power stations, show that the generation costs passed through to retail tariffs in Western Australia are significantly higher than in other states.

The recent merger between Verve Energy and Synergy should help achieve cost savings between generation and retailing and we pose the question whether more firms are required in the market carrying out similar but competing activities. We have examined the concentration of both the wholesale and retail electricity market around Synergy and suggest that it will be very difficult to create the conditions for competition at both levels while this one company controls such a high proportion of the market. The savings from the recent merger would be maintained and, we believe, enhanced by the benefits of a competitive market by the structural separation of Synergy into two or more generator/retailers.

In considering the substantial quantities of new capacity added to the Western Australian electricity market we have examined the influence of the Reserve Capacity Mechanism (RCM), which is used to assess and then attract and pay for new generation capacity in the South West Interconnected System (SWIS). The RCM is an important part of this Review as it appears to be a major contributor to the high generation costs in the SWIS. The RCM involves the acquisition of capacity by the Independent Market Operator (IMO) annually, two years in advance. In 2012-13, the market had an average capacity utilisation of just 35 per cent, meaning out of all the capacity that customers pay for on average only one third is being used.

With regard to the Western Power network, network tariffs covering transmission and distribution amount to about 37 per cent of the residential tariff. This is lower than most network service providers in the National Electricity Market (NEM), even though we might have expected Western Power's costs to be slightly higher than average given Western Australia's widespread network. The Code governing the use of the network and electricity market participants' access to the network is different to the set of rules in the NEM in a number of respects. While there is no need for it to be the same if it is operating efficiently, there are concerns that it tends to treat new market participants seeking to connect differently to established participants. This can have the effect of making it easier to keep older and higher cost plant while making it more difficult to connect newer, low cost generation.

The outlook for coal and gas supplies in the south west is also considered. The current markets for these fuels indicate that their costs are likely to rise in real terms over the coming years. Such an outlook reinforces the need to stabilise or reduce other electricity generation and retailing costs and make the supply chain as competitive and efficient as possible.

In the next four years the average cost of electricity in the SWIS is projected to increase by up to 20 per cent. Short of any significant changes in the cost outlook, or the trajectory of tariff increases relative to that announced by government, the annual subsidy from taxpayers will be over $600 million or more than $2.4 billion in these four years on a business as usual basis.

This suggests the current burden on taxpayers from the electricity subsidy paid to Synergy will increase - a major impetus for reform in itself. Increases in tariffs for both domestic and commercial or industrial customers will also continue to erode the state's competitiveness and will constrain economic growth to levels below what could otherwise be achieved. While the next four years is expected to see further increases in subsidies to customers (in the absence of reform) the longer term outlook could be even more challenging. As we have discussed above, there will be upward pressure on coal and gas prices. In addition, there will be potential increases in network costs given asset replacement costs and the expense of servicing a peakier load profile.

Should the present industry structure and market mechanism be retained, taxpayers will still be required to fund the majority of new investment (network and generation). Taxpayers currently underwrite 76 per cent of capacity in the market either through direct ownership or bilateral contract commitments.

In considering the current industry structure, we identify the dominance of state-owned enterprises and the absence of full retail contestability (FRC) as potentially constraining competition that would drive efficiencies and place downward pressure on costs.

Within the high level options discussed in chapters 4 and 5, we identify two alternative paths for industry reform. These alternatives are: progressive evolution of existing mechanisms to help deal with the dominance of state-owned enterprises and the WEM rule change processes; or, a fundamental change to the design of the marketplace. The latter would see the WEM operate in the same way as the NEM.

We also consider the continuing relevance of the current "capacity plus energy" design of the WEM. This was developed amid expectations of continuing growth in electricity demand and a primary objective of reducing risks of insufficient capacity. We identify that this market design has not coped well with a static and declining demand, or the difficulty in forecasting block loads. These circumstances have resulted in customers paying for substantially more capacity than necessary to meet design standards for system security.

In light of this, the question is posed whether a fundamental change to the industry structure and market design may be necessary to improve market outcomes and reduce costs. We observe that while the WEM rule change process has addressed some undesirable market outcomes, the rule change process in itself is not well suited to the types of fundamental change that may be required, including the option of the Western Australian market joining the NEM.

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1 The Electricity Market Review

1.1 Introduction

Regulated retail electricity prices for residential customers in the SWIS increased by 86 per cent between 2006-07 and 2013-14. Over the same period, underlying electricity costs have increased at a similar rate. Despite the significant tariff increase, it has not been enough to cover the cost of supply and the subsidy paid to Synergy for small retail customers[1] has risen sharply and will continue to do so.

Several factors have driven electricity cost increases across Australia. These include increases in network costs, subsidies for renewable energy and the carbon tax. While Western Australia has not escaped these nationwide trends, the Review looks particularly at cost increases that have arisen locally and whether they are an outcome of the industry structure and the market mechanisms existing within the WEM.

The WEM was created in 2006 and it is timely to consider how the market has performed and whether it will serve Western Australia well in coming years. There will be further upward pressure on electricity costs in the future and it is important that the Western Australian system of electricity production and delivery is the most efficient and cost effective it can be.

1.2 The Terms of Reference

On 6 March 2014, the Minister for Energy launched a broad based review of the structure, design and regulatory regime of the electricity market in the south west. The Minister expressed concern that the electricity market was not functioning as expected and has contributed to higher electricity prices. The focus of the Review is broadly to identify and address deficiencies in the market.

The Review has three objectives:

- Reducing costs of production and supply of electricity and electricity related services, without compromising safe and reliable supply;
- Reducing government exposure to energy market risks, with a particular focus on having future generation built by the private sector without government investment, underwriting or other financial support; and,
- Attracting to the electricity market private-sector participants that are of a scale and capitalisation sufficient to facilitate long-term stability and investment.

The review is being undertaken in two phases:

- **Phase 1** – assess the strengths and weaknesses of the current industry structure, market institutions and regulatory arrangements and examine options for reforms to better achieve the Electricity Market Review Objectives.
- **Phase 2** – detailed design of a set of selected reforms and implementation arrangements.

The Terms of Reference are provided in Appendix 2.

1.3 The membership of the Panel

The Steering Committee for Phase 1 of the Electricity Market Review is:

- Paul Breslin – member of the Stanwell Corporation Board in Queensland, former CEO and Director of ACIL Tasman and former Director-General of the Queensland Department of Minerals and Energy;
- Nicky Cusworth, Deputy Director General at the Department of State Development; and,

[1] Customers consuming less than 50 MWh per annum.

- Dr Ray Challen, Deputy Director General at the Department of Finance – Public Utilities Office – and Coordinator of Energy

1.4 The Review process

The Steering Committee encourages individuals and organisations to contribute towards the Electricity Market Review process by making a submission to this paper. Submissions are due by 12 September 2014. A Market Participant Consultation Group workshop and briefing will be held on 21 August 2014. Individuals who have already submitted an expression of interest for this group will be notified of the details via email.

1.5 Public Submission Process

Submissions can be made:

By email

electricitymarketreview@finance.wa.gov.au

By mail

Electricity Market Review Project Office
Public Utilities Office
Department of Finance
Locked Bag 11
Cloisters Square WA 6850

Content of Submissions

A template for submissions has not been provided, as the nature of Electricity Market Review is wide ranging and varied and it is anticipated that public submissions will be of most value if interested parties are able to make a submission in their area of expertise.

As a guide, submissions should aim to answer the relevant questions posed within each section of the Discussion Paper. They should focus on market outcomes under proposed reform options one and two, and what industry structures and market mechanisms will result in a more efficient and effective market.

Publication of submissions

Submissions will be available for public review at www.finance.wa.gov.au/publicutilitiesoffice, unless you request otherwise.

Please indicate clearly on the front of your submission if you wish all or part of it to be treated as confidential. Contact information, other than your name and organisation (where applicable) will not be published.

Requests may be made under the *Freedom of Information Act 1992 (WA)* for any submissions marked confidential to be made available. Requests made in this manner will be determined in accordance with the provisions under that Act.

1.6 Project Office Contact Details

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2 History

Western Australia's electricity industry has experienced many fundamental changes since the mid-1970s. In July 1975, the functions of the State Energy Commission and the Fuel and Power Commission were combined to form a new organisation: the State Energy Commission of Western Australia, or SECWA. SECWA became responsible for electricity production and gas and electricity distribution, retailing, industry regulation and informing the state government on matters relating to energy policy.

In the late 1980s the federal government embarked on a micro-economic reform policy agenda and the electricity industry, where significant improvements in efficiency and productivity were believed possible, became one of the most important focuses of this program. The (then) Commonwealth Industry Commission reviewed the sector and, in May 1991, released its final report recommending, inter alia, "separating ownership of key functions in each industry and progressively selling much of the publicly owned generation and distribution assets".[2]

In 1992, the state government commissioned the Energy Board of Review (EBR, chaired by Sir Roderick Carnegie) to investigate the structure of the state's electricity and gas industries.[3] The EBR delivered its final report in April 1993, recommending competition in non-monopoly parts of the gas and electricity industries.

Implementation of these recommendations involved the creation of two new entities in January 1995 – Western Power and Alinta Gas.[4] Many of the benefits foreseen by the EBR were achieved by the two new entities, including gas prices reducing considerably, new gas intensive projects attracted to the state[5] and a decrease in real electricity prices.

In August 2001, the state government established the Electricity Reform Taskforce (ERTF) with the objective of creating a more competitive electricity industry, although the ERTF terms of reference did not extend to consideration of privatisation of any part of (the then) Western Power.[6] The ERTF was asked to deliver recommendations on a number of matters including the extent of disaggregation of Western Power, FRC and a new market design in the form of the state's WEM.

The ERTF recommended the continuation of the bilateral contracts market that existed in the SWIS at that time with further evolution of the market design to be considered at a future time.[7] The ERTF also recommended the creation of a residual trading market through which energy balancing and limited trading around uncontracted energy requirements would occur. It was hoped that this would facilitate the entry of new generators and retailers.

At this time, Western Power expressed concerns that rapid demand growth, hot summers and a "peaky" load, combined with the isolation from the rest of the NEM might result in supply shortages.[8] This concern, as well as some features of the new market, such as a price cap and bidding constraints in the short-term market, led the ERTF to include a capacity acquisition mechanism. This involved the IMO forecasting capacity requirements several years ahead and ensuring that its projected capacity was acquired and passing the cost of this on to customers.

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[2] The Industry Commission, *Energy Generation and Distribution in Australia,* 1991, Preface.

[3] Energy Board of Review, WA *The Energy Challenge for the 21st Century* Western Australia 1993, pp. 9-10.

[4] See *Electricity Corporations Act 1994 (WA) (*as originally passed); *Gas Corporations Act 1994* (as originally passed).

[5] For example, the Worsley Alumina Refinery cogeneration project, TIWEST cogeneration project and the BP Refinery cogeneration project.

[6] Speech by Hon Eric S Ripper MLA Deputy Premier; Treasurer; Minister for Energy Thursday, 13 September 2001. Available at http://www.treasury.wa.gov.au/cms/uploadedFiles/State_Budget/Budget_2001_02/speech.pdf [accessed 5 June 2014].

[7] Electricity Reform Task Force, *A Framework for the Future*, p17.

[8] Western Power, *Business Case for the Construction of the Cockburn Combined Cycle Gas Turbine (CCGT*), 2001.

While the market rules required the state-owned generator (later known as Verve Energy and now Synergy) to provide standby generation and all ancillary services, the initial market design envisaged this as a transitional arrangement until sufficient alternatives were available. [9]

The ERTF's recommendations were endorsed by government in November 2002 and included the vertical disaggregation of Western Power Corporation into four separate entities – generation (Verve Energy), networks (Western Power), retail (Synergy) and regional power (Horizon Power), and the establishment of a wholesale electricity market.

The WEM was established in 2006 and steps were taken to mitigate the perceived market power of Verve Energy and Synergy. These included:

- The Vesting Contract (2006) which imposed a wholesale price cap on a significant proportion of Verve Energy's plant portfolio at disaggregation. The Vesting Contract was meant to ensure the financial viability of both Verve Energy and Synergy in the move to a competitive electricity market. It was also meant to support market development by providing appropriate incentives to both entities to progressively negotiate electricity supply agreements on commercial terms outside of the Vesting Contract arrangements;[10]
- A 3,000 megawatt (MW) cap on Verve Energy's generation portfolio, restricting Verve Energy's ability to invest in new generation plant, thereby encouraging independent generators to increase their market share over time. Renewable energy projects were not included in the cap;[11] and,
- Restrictions on Synergy generating electricity and Verve Energy retailing electricity at least until 2013 (subsequently extended to 2016).[12]

The design of the Vesting Contract has had significant implications for the development of competition in both the wholesale and retail markets. At the time of disaggregation, most of the wholesale energy sales between Verve Energy and Synergy occurred under vesting contract arrangements. However, it was expected that the influence of the Vesting Contract would reduce quickly as:

- The expiry of inherited retail contracts and increasing tariff sales created an immediate need for new bilateral contracts in the wholesale market;
- The Vesting Contract volume automatically declined as contestable tariff customers moved to contract-based offerings; and,
- Synergy "displaced" Vesting Contract volume through competitive tenders, to the extent permitted (and required) by the mandatory displacement timetable (the Displacement Mechanism).[13]

The Vesting Contract was structured on "net-back" principles, with Synergy retaining a pre-determined margin from its total revenues and the residual revenues "netted" or passed back to Verve Energy. This design had significant adverse consequences for the financial sustainability of Verve Energy. Synergy had a protected retail margin, while Verve Energy was effectively exposed to the full implications of a lack of cost reflectivity in retail tariffs. The "net-back" revenues that eventually flowed to Verve Energy were in many cases insufficient to cover its wholesale cost of supply and did not allow the business to extract a consistent return on investment.

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[9] Electricity Reform Task Force, *A Framework for the Future*, 2002 p22-23.

[10] Office of Energy, *CBSC Recommendation Paper: Vesting and Initial Supply Contracts*, 17 June 2005, p3.

[11] Ministerial Direction under the *Electricity Corporations Act 2005* to the Electricity Generation Corporation. Available at: http://www.imowa.com.au/docs/default-source/Reserve-Capacity/2006_capacity_cap_direction.pdf?sfvrsn=2 (accessed 27 June 2014).

[12] Sections 38(1) and 47(1) of the *Electricity Corporations Act 2005.*

[13] Office of Energy, *CBSC Recommendation Paper: Vesting and Initial Supply Contracts*, 17 June 2005, p5.

Under this arrangement Synergy had operated profitability since its inception but Verve Energy was subject to substantial losses.[14] These concerns, among others, were the stimulus for the Verve Energy Review in 2009.

The Verve Energy Review considered the reasons for the business' historical poor financial performance, its financial outlook and options for addressing a number of observed problems with the operation of the wholesale electricity market.

In 2009-10, Verve Energy achieved a net profit after tax of $97.5 million. The improved financial position was a result of an increase in retail tariffs in April 2009 (following a 10-year freeze) and the introduction of government subsidy payments to Synergy (the Tariff Adjustment Payment or TAP).

The Verve Energy Review recommended that tariffs and charges be further increased to "efficient levels" as soon as possible with the aim of removing barriers to retail competition. It also recommended that the Vesting Contract's Displacement Mechanism be altered as soon as possible, largely to end prescribed displacement based on Synergy's price protected market.

The Verve Energy Review also recommended that, with the advent of FRC, the Vesting Contract should expire and both Synergy and Verve Energy should be allowed to compete for market share in the generation and retail segments.

The original Vesting Contract was terminated in October 2010 and replaced with a new contract. Among other items, it removed the previous "net-back" contract structure and incorporated a much simpler pricing structure. Further, some of the energy balancing flexibility Synergy had under the original contract was removed so that the new arrangements moved closer to a contract structure more typical of private sector wholesale contracts.

Although the Replacement Vesting Contract addressed problems arising from the "net-back" arrangements and Displacement Schedule, it was nevertheless an administratively-generated solution to a market problem, and it created other market distortions of its own. In particular, the structure of the minimum energy nomination requirements (take-or-pay) levels in the Replacement Vesting Contract had the unintended consequence of Synergy buying more energy from Verve Energy than was required to service its load. Synergy sold the excess in the Short Term Energy Market (STEM). By mid 2012, the Replacement Vesting Contract had produced the bizarre situation in which Synergy was, on average, a net seller of energy in the STEM and Verve Energy was a net buyer.

In April 2013, the government announced the merger of Synergy and Verve Energy with the objective of harvesting savings from the combined entity without adversely affecting reliability, security of supply or private investment in the sector. The merger took effect on 1 January 2014, with the merged entity retaining the name Synergy. One important outcome of the merger was that existing contracts between Synergy and Verve Energy – including the Replacement Vesting Contract – fell away, removing the take-or-pay requirements under those contracts. The merged entity is now able to optimise how it utilises its generation portfolio and wholesale procurement contracts to meet its load requirements. A further consequence of these contracts falling away is that new, more flexible, contracting instruments have been put in place (such as the standard products regime). This should facilitate greater market efficiency and transparency with greater access afforded to other market participants to enhance competitive outcomes.

The merger has also made possible further opportunities for contract restructuring and flexibility and removed some of the impediments to future restructuring of Synergy, potentially arising from this, or other, reform processes. In this regard, the merger of Synergy and Verve Energy can be seen as an evolutionary step for future reforms.

[14] These losses were estimated to be in the vicinity of $250 million of pre-tax losses ($285 in 2014 dollars), out of a total of $454 million ($518 in 2014 dollars), over the three financial years; See *Verve Energy Review* 2009, Deloitte Oakley Greenwood p. 5. Available at: http://www.oakleygreenwood.com.au/images/VerveEnergyReviewFinalReportAugust2009.pdf (accessed 27 June 2014).

Through the vertical integration of its generation and retail businesses, the state is now better positioned to economically apportion the combined portfolio of generating assets, wholesale procurement contracts and retail contracts between any future horizontally-separated entities. The merger has also allowed the merged entity to focus on cost reduction, a critical underpinning of future reform.

However, as the merger combined the largest retailer in the market with the largest generator, there were understandable concerns about its size and market share. As a result, regulations were made to impose ring-fencing, business segregation, transfer pricing and non-discrimination obligations on the merged Synergy.

3 Is the market delivering?

Electricity markets were developed as a way of enabling competition in electricity generation where competition had previously been seen as impossible. Electricity cannot be stored economically and demand and supply must be matched at all parts of the system in real time. It had generally been accepted that a centrally planned and managed system was necessary to do this but market mechanisms were developed in the 1980s which promised significant improvements in the way electricity was generated and sold.

It was shown at the time that such markets could achieve much higher levels of economic efficiency than the vertically integrated monopolies they replaced.[15] Economic efficiency here refers to both short term (static) and long term (dynamic) efficiency. Short-term efficiency is maximised when at any time the system is using the lowest cost combination of plant to meet system demand and the lowest cost reserve is available to the system in the case of outages or changes in demand. Electricity markets provide this when they operate a transparent real time auction, accepting generation offers from lowest to highest price until demand is met. Most buyers and sellers in electricity markets also seek the certainty and risk management benefits of electricity contracts across the market. But a transparent real time market is essential to allow competition, transparent price setting and the basis for contract prices.

Long-term efficiency relates to the way in which the market develops over time. This includes providing timely signals for investment to enter with the size and type of plant that the market requires and for the exit of older or higher cost plant that cannot compete with new and more efficient technology. Previously, the vertically integrated and centrally planned systems increased their capacity as they saw fit and passed on these costs to customers via regulated tariffs. The risk of the investment was passed on to customers rather than borne by the investor.

These approaches to assessing market efficiency provide a reasonable guideline for assessing the performance of the WEM. Questions that are pertinent include: Do we have a transparent market that results in the economic (least cost) dispatch of plant to meet demand at any time? Is the market price a good guide for longer term contract prices? Does the market encourage appropriate entry and exit of plant? Who bears the risk of new entry?

These questions are considered further in this chapter, often through comparisons between outcomes in the NEM and the WEM and sometimes by looking at the operation of similar market mechanisms to the WEM, such as the Pennsylvania New Jersey Maryland Interconnection (PJM) in the northern United States. The contrasts do not necessarily mean that the comparison market is better performing than the WEM; they are simply a means of considering how an alternative market mechanism might achieve outcomes similar to those desired from the WEM.

In looking at the performance of the WEM we have specifically considered two features: the industry structure and the market mechanism.

Industry structure refers to the number and size of the individual generators in the wholesale market and the number of retailers in the retail market. An industry structure where no single generator has the ability to set prices in the wholesale market would provide competitive outcomes under most wholesale market mechanisms. A structure characterised by one or two generators and retailers having the ability to set wholesale prices and restricted competition in the retail market would usually not provide competitive outcomes under any market mechanism.

Market mechanism refers to the mechanism by which generator bids (sometimes called offers) are processed and ranked. Contracts are sometimes netted out of the process (the net pool) or contracts are kept separate from the pool and all generation comes through the pool and is priced in each period (a gross pool). Net pools usually include a price cap on net pool prices and therefore require a capacity procurement mechanism to ensure adequate supplies.

[15] Joskow and Schmalensee, *Markets for Power*, MIT Press, 1983.

This chapter raises a number of important questions in relation to the performance of the WEM and, after exploring them further below, seeks stakeholder feedback. These questions include:

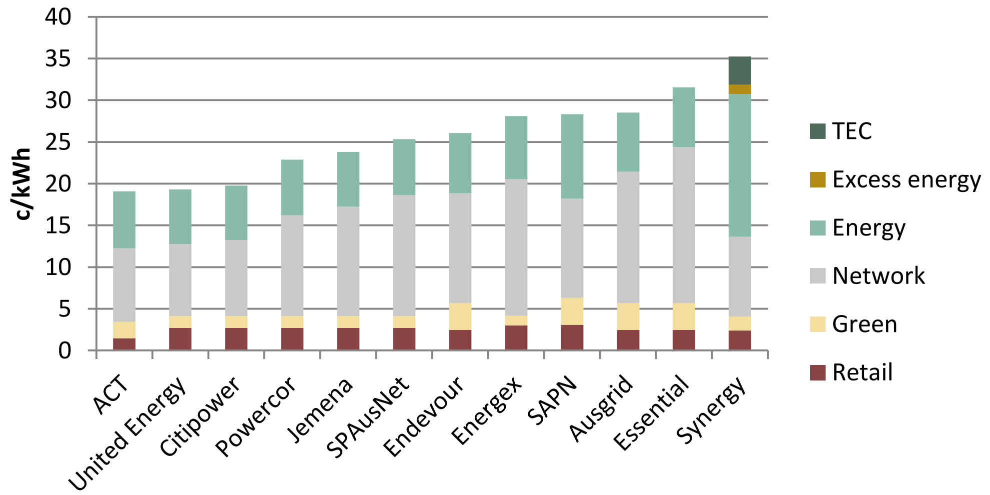
- Why is the cost of supplying electricity to retail customers so high that it requires a significant taxpayer-funded subsidy to keep tariffs at levels comparable to other Australian states?
- Could the current industry structure result in a competitive market under any market mechanism?
- Why can high volumes of generation capacity be added each year, with the costs passed through to customers, when there is often no requirement for it?
- Are network costs reasonable and does the network access code enable long term efficient entry and exit of plant?
- What does the current primary fuel situation indicate for the availability and price of fuel for future generation?
- Is the current trajectory of electricity costs and government subsidies sustainable?

3.1 The cost of retail electricity in the SWIS, why so high?

The SWIS supplies approximately 1.1 million customers and has approximately 6,000 MW[16] of installed generation and Demand Side Management (DSM) capacity. It has over 6,000 km of transmission lines, 95,000 km of distribution lines and it operates in an area of some 225,000 square kilometres.

Figure 1 shows a comparison of the components of retail electricity costs in the SWIS compared to each of the main distribution areas in Australia.[17] The data reveals that SWIS transmission and distribution costs are lower than most of the distribution areas shown, which is contrary to expectations as the SWIS is a longer and less dense network than most (other than SAPN and Essential).

Figure 1: Retail cost stack (including the Tariff Equalisation Contribution (TEC) in the case of Synergy), 2014



Source: Sapere

Note 1: "Excess energy" is an estimate of the impact of excess capacity costs allocated to the A1 tariff class plus 10 per cent of allocated carbon costs.

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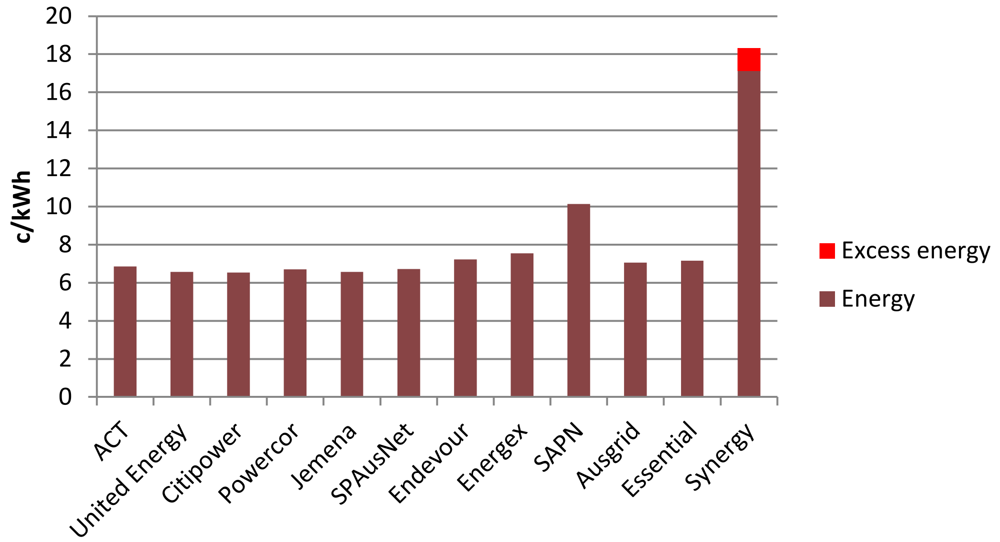
[16] IMO *Capacity Credits assigned since Market Commencement* 2013. Available at: http://imowa.com.au/docs/default-source/Reserve-Capacity/capacity-credits-since-market-start-up-to-15-16.pdf?sfvrsn=0 (accessed 27 June 2014).

[17] The Synergy cost stack is compared with the cost stack associated with minimum retail tariffs in each jurisdiction. Analysis of typical retail tariffs in NEM jurisdictions showed that there was material retail residual associated with these tariffs, so it is considered that comparison with minimum tariffs provides a better indication of efficient costs.

Note 2: Carbon costs are included in the above graph, but embedded in energy prices as they are not transparent in all jurisdictions.

Figure 2: Wholesale electricity cost comparison for 2013-14



Note 1: 'Excess energy' is an estimate of the impact of excess capacity costs allocated to the A1 tariff class plus 10 per cent of allocated carbon costs.

Note 2: Carbon costs are included in the above graph, but embedded in energy prices as they are not transparent in all jurisdictions

The retail and wholesale cost stacks shown in Figures 1 and 2 reflect that while Synergy's network costs are low relative to its peers, its cost of wholesale energy is significantly greater than most other regions in Australia. Specifically, the portfolio generation cost (energy and capacity inclusive of carbon) attributed to A1 class customers in the SWIS is approximately $180 per MWh,[18] whereas a typical portfolio generation cost in most other Australian jurisdictions is in the range of $60 - $80 per MWh. The exception is South Australia where the typical portfolio generation cost is higher than the average, being over $100 per MWh.[19] South Australia currently relies more heavily on gas fired generation and wind power, and imports electricity from other states.

In Western Australia a part of the large difference in generation costs arises from factors such as coal costs in Western Australia being higher than that of Victoria, NSW and Queensland. In addition, Western Australia uses a somewhat higher proportion of gas for generation than most other states. However, coal costs and additional use of gas do not explain such a significant difference in costs.

Some specific reasons for higher generation costs in the WEM appear to be:

- Capacity costs, which are not charged in any other Australian jurisdiction, are high reflecting the costs of excess capacity being allocated to retailers and ultimately customers.
- Costs embedded in bilateral contracts appear high, possibly reflecting the relatively low transparency around forward prices (including difficulties in marking existing contracts to market) relative to the NEM.
- Competition among generators is weak.

The Western Australian wholesale prices shown in Figure 2 are significantly higher than prices set in the STEM or the balancing market where there is a competitive process and limits on

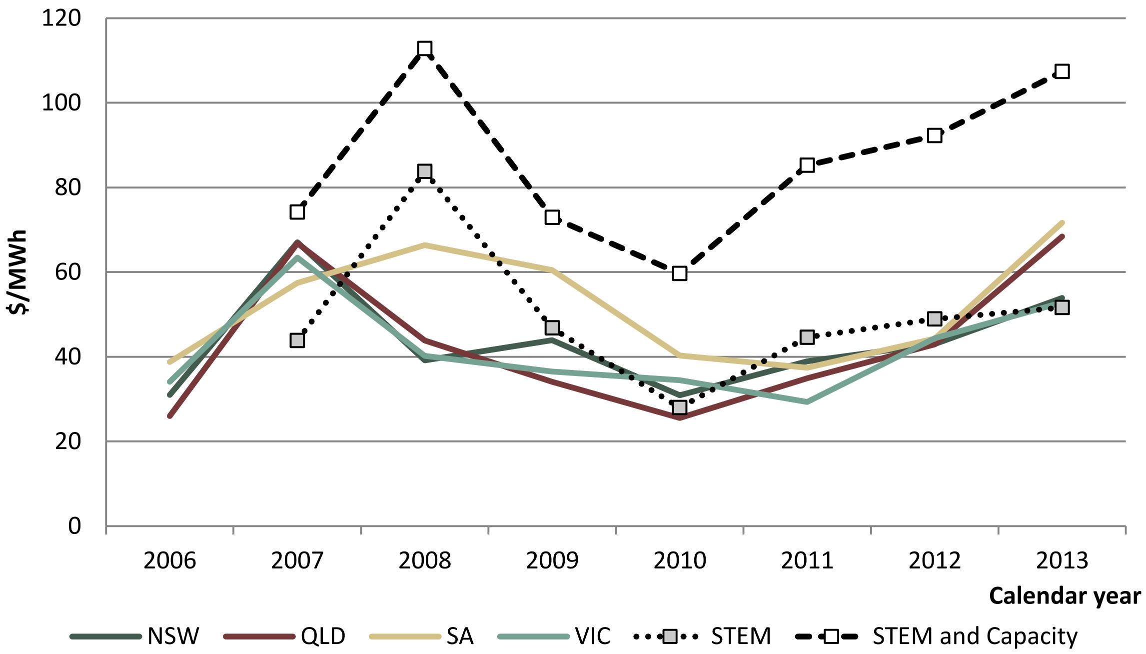
[18] Sapere analysis for the PUO, unpublished.

[19] Sapere analysis for the PUO, unpublished.

Synergy's ability to set prices. Figure 3 shows annual average wholesale prices for the four mainland regions in the NEM and annual average STEM prices. It also shows annual average STEM prices plus capacity costs.[20] While the cost of generation for small residential and business customers is usually higher than average market prices, because of their higher consumption at peak times, the wholesale market should usually provide a reasonable guide to generation costs in retail prices. In the case of residential customers on the A1 (most common) tariff this is clearly not the case.

In other words, market prices appear to be irrelevant for a large proportion of customers in the SWIS as contract prices and transfer prices across Synergy appear unrelated to market outcomes. As no other retailer is allowed to compete for this section of the market it is not possible for another retailer to buy from the STEM or the balancing pool and offer residential customers lower prices as they have done in other parts of the contestable retail market.

Figure 3: NEM annual average pool prices and annual average STEM and STEM plus capacity prices



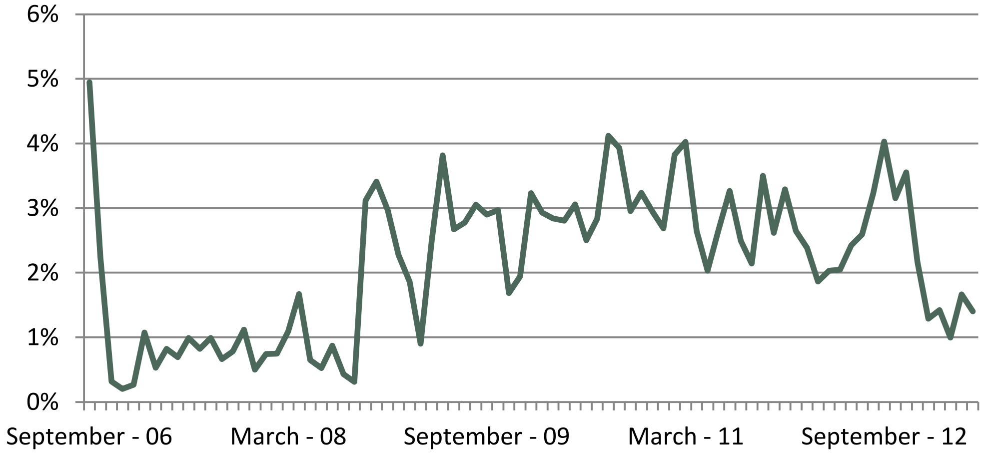
Source: AEMO, IMO data and ACIL Allen

Within the WEM, there are two markets in which participants are able to trade electricity; the day-ahead STEM and the Balancing Market.[21] The latter accounts for the differences between participants' net contract positions (following STEM trades) and actual outcomes.

[20] With the capacity cost on a megawatt per hour (MWh) basis.

[21] Participation in the Balancing Market is mandatory for non-intermittent generation facilities with a capacity exceeding 10 MW.

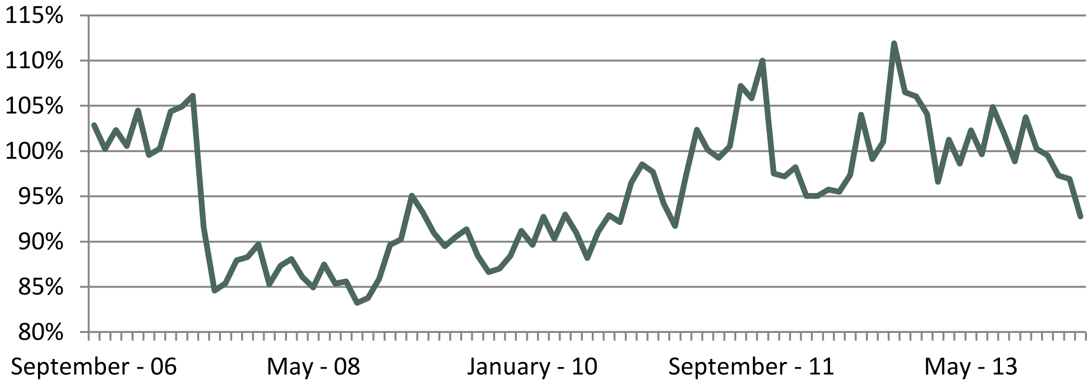
Figure 4: Monthly average proportion of STEM offers traded



Source: IMO

Figure 4 shows the percentage of "STEM offers that become trades" averaging around three per cent over the period since market commencement. Figure 5 shows the proportion of generation sold under bilateral contracts.

Figure 5: Average percentage of total generation that is bilaterally contracted[22]



Source: IMO

Achieving lower energy prices in the retail market therefore appears to rely on bilateral contract prices and transfer prices from the wholesale business unit to the retail business units of Synergy being set in a more competitive environment. This in turn would appear to require a larger number of competitors in the wholesale market, so that the influence of one large incumbent is reduced. If this happened, the implementation of FRC might then allow competitive prices in a wholesale market to be passed on to customers.

The limit on Synergy (and previously Verve Energy) building new plant was intended to reduce their market presence over time as new private sector generation entered to meet the growth in demand. This has not yet occurred sufficiently and, on the basis of current growth rates, it is unlikely to occur for some decades to come. As a consequence it is likely that, without reform, current high generation costs will continue to be charged to non-contestable customers and the current high level of taxpayer-funded subsidy will need to be continued if tariffs are to be kept at reasonable levels. The current industry structure and lack of retail contestability will ensure this.

[22] Bilateral figures derived from what participants submit as their interval contracted requirement to supply; total generation is the sum of recorded meter readings. Where the average is over 100 per cent, this represents a situation where contracted submissions are higher than what was actually required.

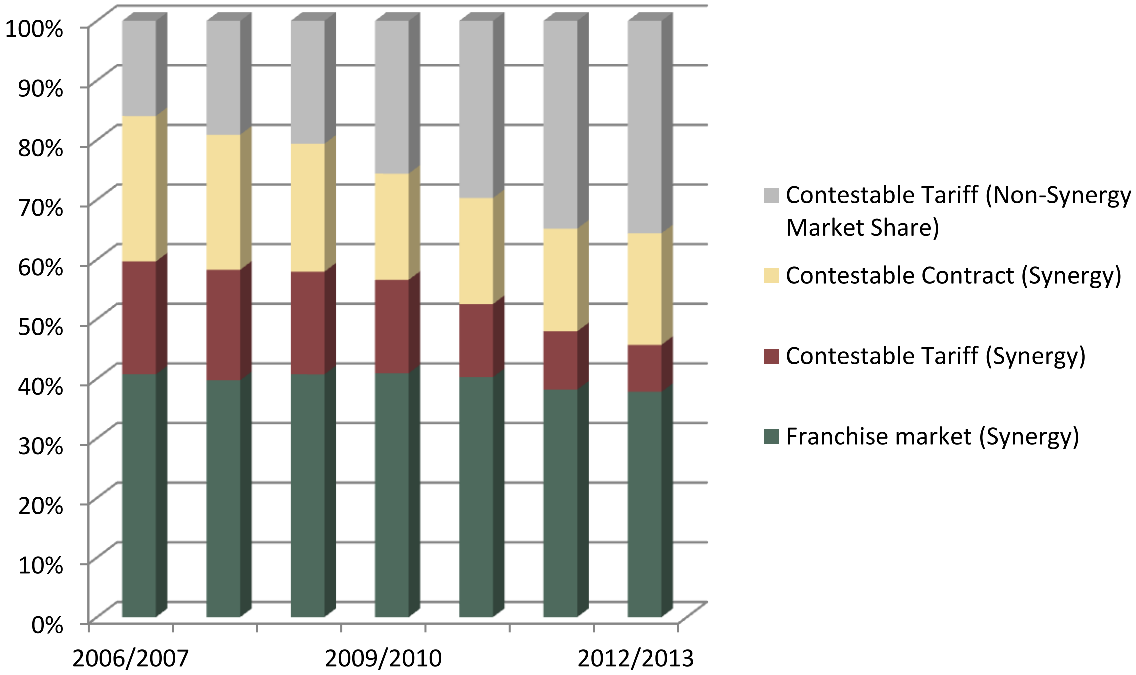
Market concentration

Customers who use between 50 MWh and 160 MWh per year are contestable but can also choose to be supplied by Synergy on a regulated tariff plan. Those consuming greater than 160 MWh per year are wholly contestable so are in effect the only segment in the market subject to effective competitive market forces. Residential customers using less than 50MWh per year are not contestable and are served by Synergy.

FRC has been (or is being) introduced in most NEM jurisdictions and Western Australia has implemented retail contestability for the natural gas supply industry (though Synergy is prevented from competing in the segment of the gas market that consumes less than 180 GJ per year).[23] It would potentially be advantageous to enable Synergy to compete in residential segments of the gas market but similarly allow other retailers to compete in the residential segment of the electricity market.

Figure 6 shows that although its share has been decreasing, Synergy retains a major position in the retail electricity market with over 60 per cent of all sales.

Figure 6: Retail market share in the SWIS by wholesale energy purchased



Source: Synergy

Retail market concentration is a reflection of the level of concentration in the wholesale market. While the NEM as a whole is a much larger and more diverse market, the retail market within each state is significantly less concentrated than is currently the case in the SWIS. This higher level of competition is because of the move towards FRC; which has been or is being implemented in all NEM jurisdictions except Tasmania.

[23] Public Utilities Office *Gas Market Moratorium* Department of Finance. Available at http://www.finance.wa.gov.au/cms/content.aspx?id=17541 (accessed 3 June 2014).

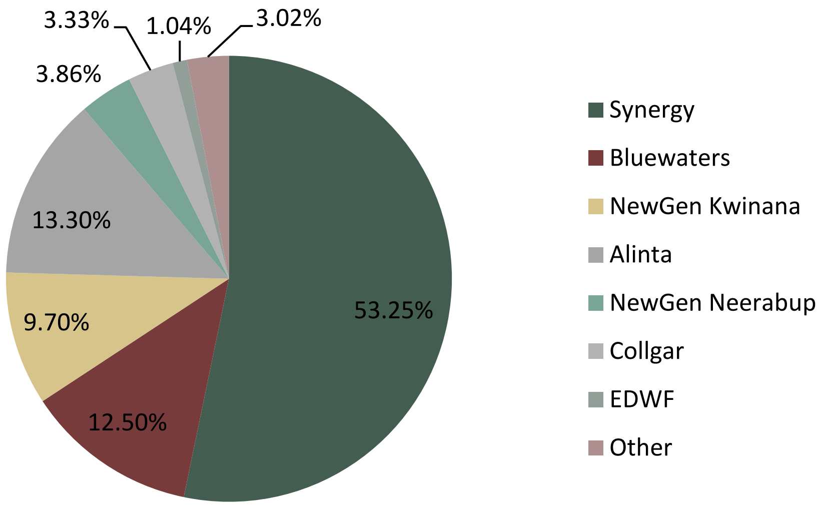
Table 1: Retail market share in the NEM and SWIS (per cent)

Retailer	NSW	QLD	VIC	SA	TAS	WA
Synergy						65.2
Origin Energy	29.2	13.9	20.7	16.1		
Energy Australia	24.8	9.5	17.4	9.0		
AGL	16.7	8.8	17.4	50.5		
Aurora Energy			0.8		94	
CS Energy		19.2				
Ergon Energy		15.7				
SECV			13.9			
Macquarie Generation	10.5					
ERM Power	5.2	9.8	7.0	2.6	6	2.1
Momentum Energy	3.3	1.0	5.9	5.2		
Stanwell	2.1	5.3				
Red Energy	1.8		2.9			
Powerdirect	1.1		2.9	3.6		
Sun Retail		7.9	0.8			
Lumo Energy			2.9	2.4		
Simply Energy			2.8	4.7		
Alinta			1.1	4.6		10.3
Southern Cross						0.6
Landfill Gas and Power						0.7
Tiwest						0.9
Premier Power						3.8
Bluewaters Power Sales						7.4
Perth Energy						7.7
Other	5.4	8.9	3.3	1.3	0	0.4

Source: AER and IMO

While Synergy's market share has reduced since 2006 when it accounted for 85 per cent of total energy sales, it continues to hold a majority share of generation facilities and energy sales in the SWIS.

Figure 7: Generation market share by output, July 2014.



Source: IMO

Synergy is also the major buyer of the output of several power stations listed in Figure 7 such as Bluewaters, NewGen Kwinana, the Emu Downs Wind Farm (EDWF) and Collgar Wind Farm.

Achieving full retail contestability

Achieving a competitive retail market under FRC would require changes to the way some current subsidies are administered. The first, which is an impost rather than a subsidy, is the TEC. This is levied on all customers in the SWIS and is used to fund a subsidy to Horizon Power to support uniform tariffs across the state. The level of TEC collected from customers in 2013-14 is estimated to be $209 million,[24] however it is expected to decrease to $136 million in the 2014-15 financial year.[25]

It is not uncommon for state governments to support uniform tariffs by subsidising distribution costs in regional and remote locations. However, in other jurisdictions the funding of these policies is most commonly achieved through a community service obligation (CSO) payment made from consolidated revenue rather than by a charge on non-regional customers.

The second subsidy, the TAP, is paid from consolidated revenue. This effectively reduces the level of all Synergy tariffs that are considered not cost reflective, including the A1 tariff. This subsidy has more than doubled since its introduction, increasing from $167.2 million[26] in 2010 to $495 million in 2013-14.[27] In 2012-13 the TAP represented an average annual subsidy of $427 per franchise customer.[28] This equates to a subsidy of approximately 34 per cent of the cost of electricity for the average residential customer supplied under the A1 tariff. In future years, even under scenarios which assume tariff increases in excess of the Consumer Price Index, the TAP has the potential to increase. According to budget estimates, it will be $472 million in 2016-17.[29]

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[24] Electricity Industry (Tariff Equalisation Contribution) Notice (No. 1) 2013, published in Government Gazette No.67 on 26 April 2013.

[25] Electricity Industry (Tariff Equalisation Contribution) Notice (No. 1) 2014, published in Government Gazette No. 49 on 4 April 2014.

[26] Synergy *Annual Report* 2010. Available at: https://www.synergy.net.au/about_us/annual_report.xhtml (accessed 27 June 2014).

[27] Department of Treasury, 2014-15 Budget papers no. 3 (Economic and Fiscal Outlook) table 8.7. Available at: http://www.treasury.wa.gov.au/cms/uploadedFiles/State_Budget/Budget_2014_15/2014-15_bp2_vol2.pdf.

[28] Synergy data provided to PUO, unpublished.

[29] Department of Treasury, 2014-15 WA Budget Paper No.3, (Economic and Fiscal Outlook), Appendix 8, p297. Available at: http://www.treasury.wa.gov.au/cms/Budget_TwoColumns_Content.aspx?pageid=13737&id=2018 (accessed 27 June 2014).

Apart from concerns over its increasing cost to government, the TAP may also act as an impediment to introducing competition to the retail market as it provides an advantage only available to Synergy. There are other ways of administering the TAP. One approach is to give it to individual customers rather than provide it as a lump sum to a retailer. It may also be provided to franchise customers as a subsidy paid through the distribution tariff.

There are also a number of other barriers for new retail competitors which need to be addressed to achieve a more competitive retail market. For example, restrictions on metering allow Western Power to provide meter data and infrastructure services. This severely restricts the product offerings of entering retailers unless they (or the customer) fund the installation of an interval meter. Additionally, under the *Customer Transfer Code 2004*, a retailer may not submit more than 20 requests for customer data per business day,[30] severely limiting the number of customers they can transfer to them and effectively preventing competitors from building a viable customer base.

Regulatory requirements for customer protection can also be a barrier to entry, given requirements in Western Australia are different to those of NEM jurisdictions, which have or have committed to adopting the National Energy Customer Framework (NECF). The marginal cost of an established retailer in the NEM acquiring a new customer in Western Australia can be much higher than acquiring one in a NECF jurisdiction due to the additional compliance costs associated with regulatory requirements for customer protection.[31]

Discussion questions

In developing competitive electricity markets how important is the structural separation of Synergy into several generators and retailers?

Should the retail electricity market be opened to FRC and should all retailers also be able to retail gas?

3.2 The capacity mechanism, is it delivering the right capacity at a reasonable cost?

When the WEM was formed in 2006 the decision to keep Verve Energy as a single generator had an important influence over the subsequent design of the market. The presence of a single generator controlling (then) over 80 per cent[32] of capacity was a concern for the potential entry of both generators and retailers. It would have constituted too high a risk for most potential new investors in the market.

Instead of splitting Verve Energy's generation portfolio to allow a level of competition, even if only between state-owned entities, the market designers opted to include a price cap in the STEM and limits on the prices that Verve Energy could bid. Verve Energy was also constrained by government policy from building new generation to service load growth. This was to allow room for the private sector, whose presence was expected to build as rapid demand provided more opportunities for privately owned generation.

It was recognised at the time, however, that price caps on the market would remove one of the most important functions of an electricity market (and any market for that matter); which is to provide price signals for new entrants to invest in the market when new production capacity is needed. Moreover, the price signals provided in electricity markets indicate the type of new

[30] Electricity Industry Customer Transfer Code 2004 published in Government Gazette No. 233 29 December 2004, p.6287. Available at: http://www.erawa.com.au/cproot/2447/2/Customer_Transfer_Code_2004.pdf (accessed 27 June 2014). Please note that this is the subject of a review of the customer transfer code currently being undertaken by the Public Utilities Office. More information can be found at http://www.finance.wa.gov.au/cms/content.aspx?id=17838.

[31] As discussed in Sapere Research Group, *Review of Competition in the Retail Electricity and Natural Gas Markets in New South Wales - Report of Interviews with Energy Retailers*, February 2013.

[32] IMO, *Statement of Opportunities South West Interconnected System* 2005 p.22. Available at http://www.imowa.com.au/docs/default-source/Reserve-Capacity/2005_soo_final.pdf?sfvrsn=2 (accessed 27 June 2014).

capacity needed. In the absence of such signals a centrally planned mechanism is required to ensure that supply continues to meet demand every minute of the year. Effectively, the constraints on bidding levels and a market price cap result in the loss of long term, or dynamic, efficiency and this function is replaced by a centrally planned capacity procurement mechanism.

In a market such as the NEM, where new entrant investors make their decisions based on market prices and are free to enter or exit when they believe conditions are right to do so, new entrants bear the financial risk of their decision. In a market with a capacity procurement mechanism the financial consequences of inaccurate forecasts, either high or low, are passed on to the customer.

The WEM RCM is an important part of this review as appears to be a major contributor to the high generation costs existing in this market. The RCM involves the acquisition of capacity by the IMO annually, two years in advance. The capacity requirement is set by reference to a system maximum demand forecast that has a 10 per cent probability of being exceeded (i.e. has a likelihood of occurring one in ten forecast years) plus allowances for a reserve, intermittent load and frequency maintenance.

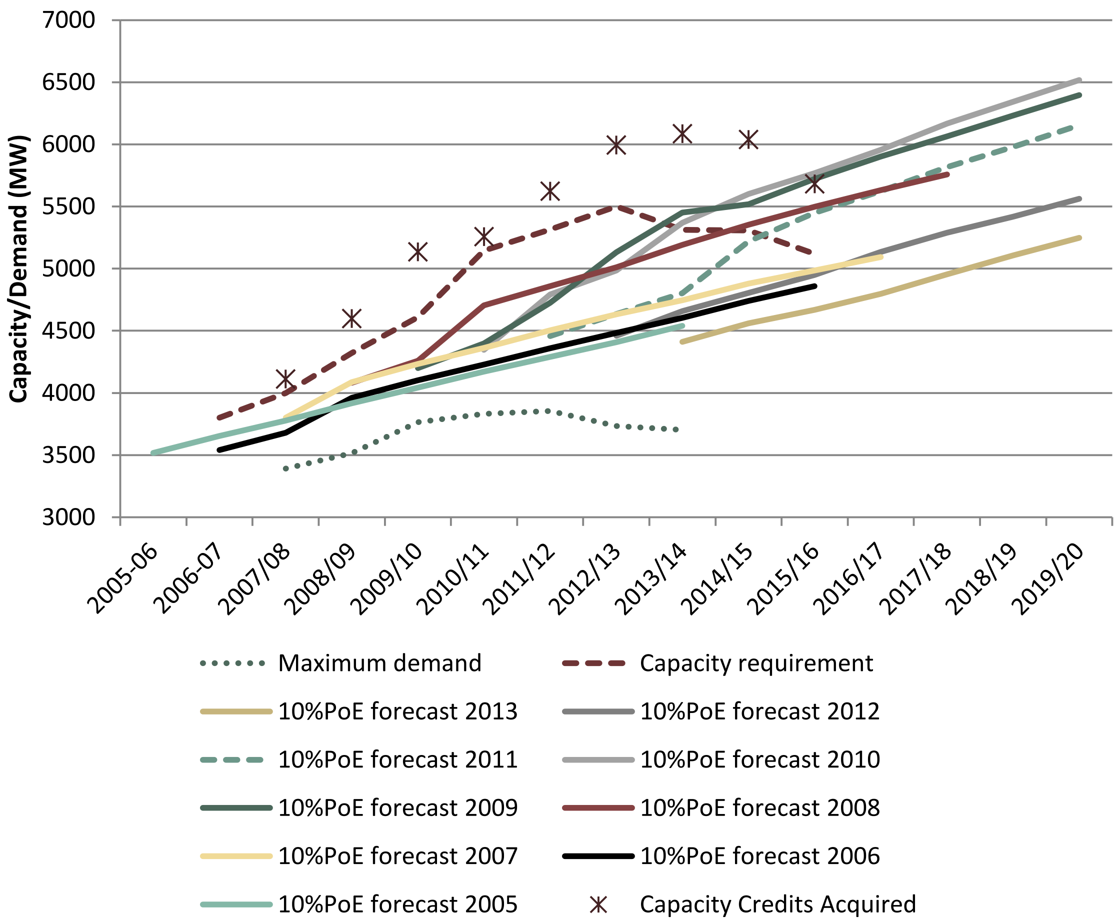
The RCM allows retailers to secure the required amount of capacity through bilateral contracts or to purchase it from the IMO, which is required to secure capacity to meet any shortfall in the predetermined requirements two years in advance. In order to meet any shortfall, the IMO sets a maximum price for capacity based around the long run cost of a new gas turbine of appropriate size to the SWIS (the Maximum Reserve Capacity Price or MRCP).[33]

In setting the reserve capacity price, the MRCP is discounted by 15 per cent and then further adjusted by the ratio of required capacity to the level of capacity accepted by the IMO. The IMO accepts offers of capacity from all parties who make acceptable offers. The price of capacity paid is then reduced proportionately so that the total amount paid remains at the same level as if only the required amount had been accepted at the MRCP discounted by 15 per cent. Interested parties that have generation facilities or demand side management (DSM) programs that are certified by the IMO are generally assigned Capacity Credits for those facilities.

A study of the operation of the capacity market in the WEM provides an indication of why generation costs, and capacity costs in particular, are so high. Figure 8 shows the IMO demand forecasts (10 per cent probability of being exceeded) undertaken in July in consecutive years from 2005 to 2013. It also shows the actual demand (dotted line). The 2013 forecast is essentially a simple extrapolation of the 2005 forecast. The intervening year forecasts (2006 to 2012) were all significantly higher, with forecasts largely increasing to 2010 and then lower in each year until returning to the 2005 forecast trend in 2013.

[33] The methodology is set out in detail in an IMO Market Procedure in accordance with market rule 4.16.

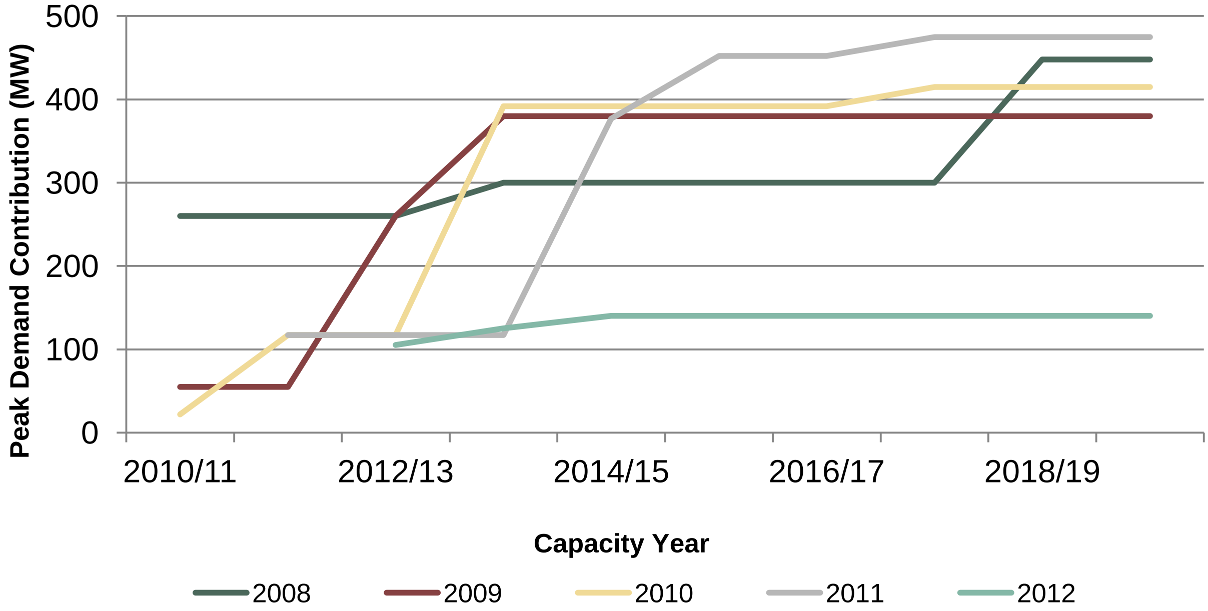
Figure 8: WEM historical forecasts compared to actual demand



Source: IMO, ACIL Allen

One of the problems the IMO faces in forecasting and acquiring new capacity is how to take into account the added demand from new mining loads and other projects using large quantities of electricity: so-called block loads. These loads are often prospective, being highly uncertain when they are included in the RCM forecast. By their nature they inflate the forecast significantly. Figure 9 shows the fluctuations of block load forecasts in successive forecasts. The IMO then acquires capacity to cover block load requirements even if a final decision to proceed on the project has not yet been made. The capacity acquired – typically open cycle gas turbine peaking plant and DSM – is not suitable for supplying the energy requirements of these large block loads, which typically have a large base load requirement. If the project does proceed it will acquire its own electricity contracts, including capacity, in addition to the capacity acquired in expectation by the IMO. In a market prone to large block loads from resource projects whose prospects fluctuate considerably with resource prices, two-year ahead demand forecasts will be prone to error and over-estimation.

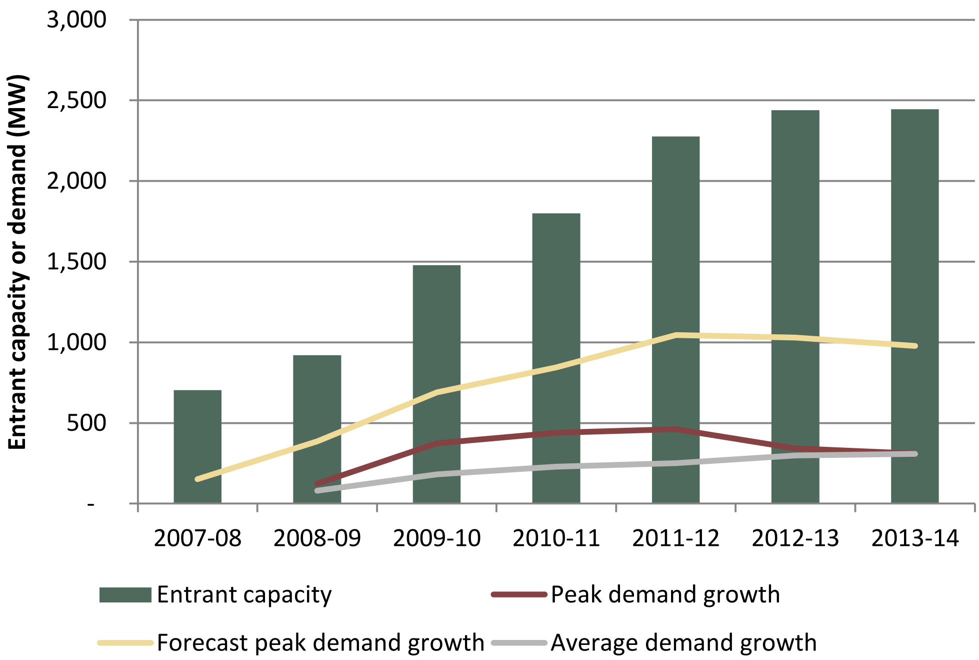
Figure 9: IMO forecasts of block loads



Source: IMO data

Figure 10 shows the cumulative entry of new capacity into the WEM for 2007-08 to 2013-14. Apart from wind technologies, which are likely to have been driven by the Renewable Energy Target, more than half of the capacity procured over this period was open cycle turbines using either natural gas or liquids. Cumulative entry over the period was just under 2,500 MW, which is considerable given that the current one-in-10 year maximum demand forecast is a little over 4,000 MW.

Figure 10: Cumulative new entrant capacity, demand growth and forecast demand growth



Note: A little over 400 MW of gas steam turbine plant was closed by Synergy (formerly Verve Energy) – part at the end of 2008 and the rest in 2011.

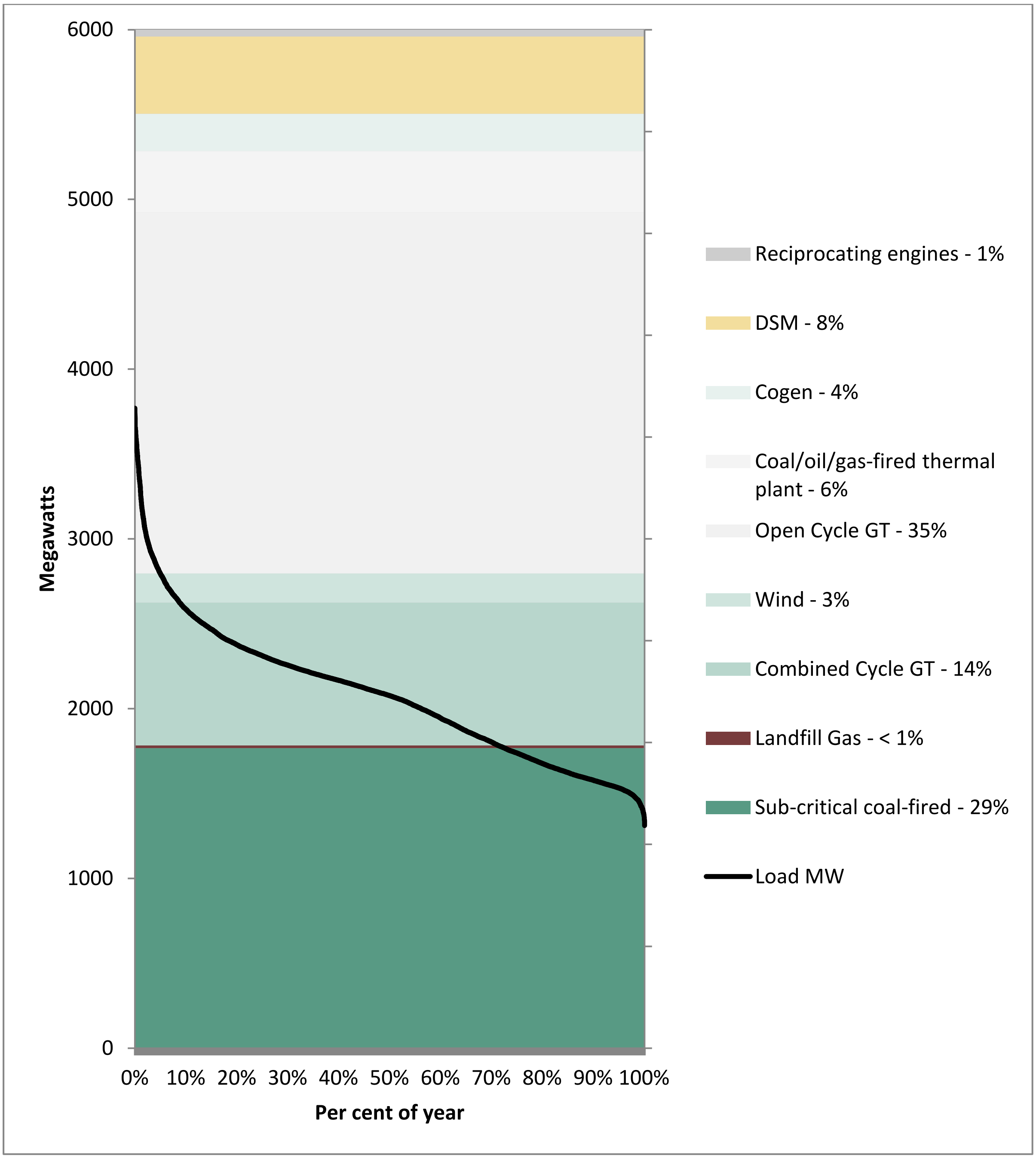
Source: IMO and ACIL Allen analysis.

The previous chart does not include the volumes of DSM that were also offered into the capacity market in each of the years shown. In 2012-13 around 430 MW of demand side response was accepted by the market operator. This capacity received the same capacity payments per MW as each generator that was certified by the IMO.

The volume and type of excess capacity added to the WEM in successive years is an indication that the RCM, as it currently operates, is failing to facilitate efficient new entry. While the load factor on the SWIS is relatively low and some new entrant peaking capacity would be expected, the volume of peaking capacity being paid for by customers is clearly in excess of market requirements. As an example, the average capacity utilisation for the WEM in 2012-13 was just 35 per cent. This means out of all the capacity that customers pay for on average only one third is being used.

Figure 11 shows the WEM load duration curve compared to the current capacity, including DSM.

Figure 11: Load duration curve compared to installed capacity and DSM, 2012-13



Source: IMO and PUO calculations.

In attempting to estimate the costs of forecasting errors in determining future capacity requirements we have used the data shown in Figure 8. In that figure the July 2013 forecast follows the July 2005 forecast trend. The intervening annual forecasts lie well above that trend. If the intervening annual forecasts are compared to the trend and capacity requirements adjusted to those forecasts (allowing for the absolute margin applied by the IMO above the 10 per cent probability of exceedance forecast in each year) an estimate can be made of the quantity of capacity credits in each year caused by the combined excess forecast and excess purchases. This is shown in Table 2. It is estimated that this combined effect cost $1.03 billion over the nine year period at an average cost of $114.4 million per annum (in nominal prices) in excess of what was needed to ensure a reliable system.

Table 2: Excess capacity (incl. forecast error) costs 2007-08 to 2015-16

Year	10per cent POE trend (MW)	Capacity requirement margin over 10per cent POE Forecast (MW)	Capacity requirement at Trend (MW)	Capacity acquired (MW)	Excess capacity (MW)	Capacity Price ($/MW)	Cost ($m)
2007-08	3,655	200	3,855	4,113	258	127,500	32.9
2008-09	3,779	241	4,020	4,600	580	97,834	56.7
2009-10	3,917	349	4,266	5,136	870	108,462	94.4
2010-11	4,044	442	4,486	5,259	773	144,231	111.5
2011-12	4,171	455	4,626	5,493	868	131,801	114.4
2012-13	4,291	515	4,806	5,996	1,190	186,003	221.3
2013-14	4,409	510	4,919	6,087	1,168	178,471	208.5
2014-15	4,539	504	5,043	6,040	997	122,427	122.1
2015-16	4,668	451	5,119	5,683	564	120,199	67.8
Total							**1,029.5**
Average		**407**			**808**	**135,214**	**114.4**

Note: Forecast excess capacity is the excess over the 2005 and 2013 10 per cent POE trend forecast.

Absolute reserve, intermittent and frequency keeping margin is the same as that allowed by IMO in each year – likely to be a conservative adjustment.

Source: IMO and ACIL Allen analysis.

It is notoriously difficult to forecast peak electricity demand only one year ahead, but a two year ahead forecast is even more challenging. The weakness of the RCM lies not in the forecasting ability of the IMO, as this is likely to be no better or worse than other forecasting efforts undertaken over the same period, but in the use of a process so prone to error and over-estimation to determine such a large proportion of electricity costs. The costs of over-investment are not borne by the investors themselves, as they would be in the NEM and in most commodity markets, but by customers and ultimately by government, which provides a subsidy to shield customers from such costs.

Table 3: Components of Maximum Reserve Capacity Price ($ per MW per year)

Capacity Year	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17
Power Station Cost	$79,110	$107,404	$135,701	$134,901	$149,306	$158,710	$113,971	$104,178	$119,942
Transmission Costs	$16,558	$18,017	$20,672	$13,151	$58,493	$51,621	$12,329	$12,164	$16,127
Fixed O&M	$23,900	$13,363	$14,392	$13,431	$27,335	$26,649	$33,384	$34,239	$33,238
Fuel Costs	$2,907	$3,456	$2,631	$3,151	$2,615	$2,825	$2,239	$4,680	$5,442
Land Costs	$0	$0	$0	$293	$769	$818	$1,973	$1,783	$2,064
MRCP (nearest $100)	$122,500	$142,200	$173,400	$164,100	$238,500	$240,600	$163,900	$157,000	$176,800
Excess Capacity	6.4%	11.4%	2.2%	5.8%	9.0%	14.6%	13.8%	11.0%	n/a
Reserve Capacity Price (per year)	$97,837	$108,459	$144,235	$131,805	$186,001	$178,477	$122,427	$120,199	n/a

Source: IMO

Table 3 shows the annual calculation of capacity prices in the WEM each year back to 2008-09. In other capacity markets, where capacity prices are set competitively, capacity prices generally trade well below the cost of new entry of peaking capacity. This in part reflects the effect of competition on prices where excess capacity exists and also the expectation that gas turbines might be expected to recover some returns to capital from sales of energy above their short run marginal cost (SRMC). For example in the PJM, capacity auctions for the years 2007-08 to 2016-17 traded between $US11/MW/year and $US63,600/MW/year. The assessed cost of new entry for a gas turbine in the PJM market was above $US100,000/MW/year for all years over that period. This suggests that participants in the PJM capacity market are able to derive more revenue through the sale of energy.[34]

While not a complete like for like comparison, the WEM average capacity price was about four times that of the PJM market. While capacity auctions of the PJM kind can work to reduce capacity costs in competitive markets, they may be difficult to run in markets which are not competitive and where the auction might be dominated by one generator.

Discussion Questions

Could alternative capacity mechanisms work within the current industry structure?

Could the capacity mechanism be carried out one year ahead rather than two years to minimise forecasting error?

Are there other ways to provide the market with sufficient reserve at lower cost?

3.3 The network: enabling a competitive and reliable wholesale market?

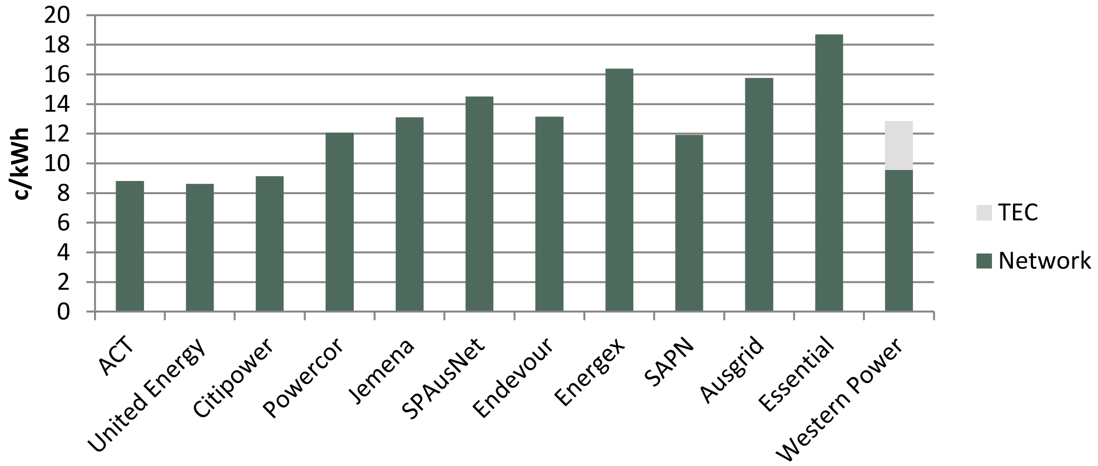
Network costs represent about 37 per cent[35] of the residential tariff's cost stack in the SWIS (including the TEC). The level of network costs in the SWIS' residential tariff cost stack falls around the middle of the group when compared to network service providers in the NEM.[36] The efficiency of the network is a significant factor in determining the efficiency of the WEM as a whole. This section considers the influence of several important features of the network access code and the way it is administered and the way the network is regulated.

[34] Analysis by ACIL Allen for the PUO, unpublished.

[35] TEC inclusive, based on analysis by Sapere for the PUO, unpublished.

[36] Analysis by Sapere for the PUO, unpublished.

Figure 12: Network cost comparison 2013-14 (residential cost stack)



Source: Sapere analysis

Network planning and connection

Western Power plans its network to meet the criteria in the Technical Rules.[37] These criteria are in the form of deterministic standards that vary across the network and over time.

In 2006, there was sufficient capacity in Western Power's network to generally meet these standards and to provide "unconstrained network access" to connected generators. However, as the SWIS has grown it is becoming more difficult and expensive to provide unconstrained access. Concerns have also been expressed that the unconstrained access approach could lead to inefficiencies in the way generators are selected to run to meet demand and in the connection of new generation to the network. There is also a concern as to whether "unconstrained access" could lead to over-investment in transmission in the SWIS. For example, in 2010 the Economic Regulation Authority (ERA) suggested that while an unconstrained network approach facilitates simpler operation of the power system and the wholesale market, it does not serve the Market Objectives for the following reasons:

- It does not promote the economically efficient supply of electricity because it is likely to cause investment in assets that may have a low utilisation;
- It creates a barrier to competition, as new entrant generators must pay a proportion of the costs of the next network augmentation; and,
- It is not clear that it minimises the long term cost of supply, in the sense that the requirement may provide more reliability than customers are willing to pay for through increased electricity prices.[38]

However, it does not appear that concerns about over-investment have been borne out in reality. Over the last decade, new generators seeking to connect to the network have generally not been prepared to fund the cost of augmentations for the deep network connections that are needed to maintain unconstrained access. Consequently, Western Power has permitted generators to connect to the network on a constrained basis through the implementation of run-back schemes[39] (25 of which are currently in place in the SWIS[40]) or through other forms of non-firm connection.

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[37] Western Power *Technical Rules* Section 2.5. Available at: http://www.westernpower.com.au/aboutus/accessArrangement/Technical_Rules.html (accessed 27 June 2014).

[38] Economic Regulation Authority, 2010 *Wholesale Electricity Market Report to the Minister for Energy,* June 2011, pp. 25.

[39] Run-back schemes are agreements between generators and Western Power that generators will reduce, or run-back, their output under certain network conditions usually concerning the loading on related transmission lines and network facilities.

[40] Based on Frontier Economics' analysis through discussions with Western Power.

These arrangements are consequently very similar to the way in which generators connect in the NEM and in other markets such as New Zealand. In both cases, generators are permitted to connect on the basis of their own assessment of the extent to which likely future network congestion might affect their ability to either be dispatched in merit order or the price at which they will be dispatched.

Existing runback schemes in the SWIS do not affect the dispatch of generators who are not party to those schemes. Generators with constrained access are turned down if an event referred to in their connection agreement occurs, whereas generators with unconstrained access are not turned down under the same circumstances. In these cases the differential treatment of different generators in the dispatch process is not based on generators' costs or bid prices but on the provisions of their respective connection agreements. Therefore, generators who connected when network capability was less scarce effectively have dispatch priority over more recently connected generators whose access is subject to runback schemes. This will often not be consistent with economic efficiency because providing certain generators with dispatch priority over others irrespective of their relative operating costs will in general not minimise the resource cost of dispatch. In other words it will lower the static or short term efficiency of the WEM as a whole.

Discussion questions

Would it be more efficient, and cheaper for new entrants, to move to an access code based on constrained connection for all parties connected, similar to that applying in the NEM?

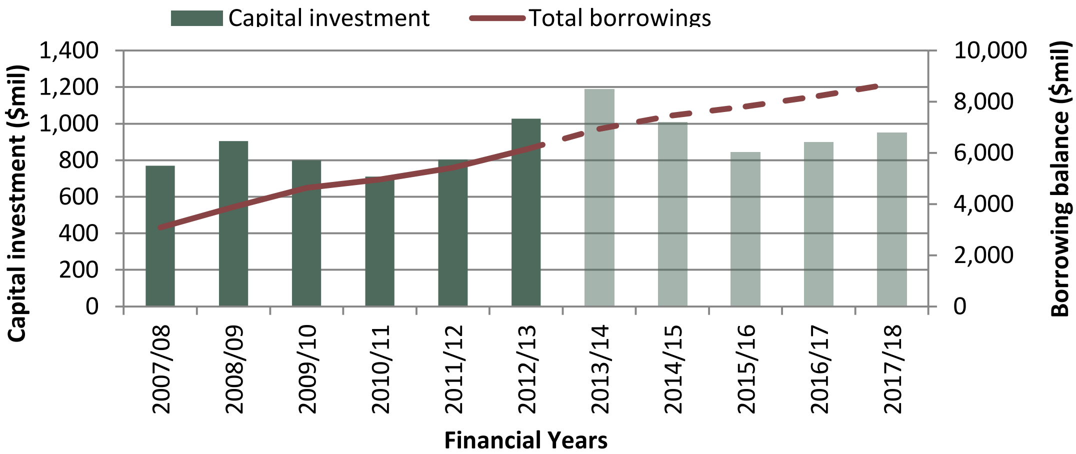
Pricing and funding arrangements

A revenue cap form of regulation has been adopted for Western Power which determines the maximum allowable revenue Western Power can earn from network charges over the period of its approved Access Arrangement. The primary incentive under the existing regulatory framework is the opportunity for Western Power to efficiently provide operating services and deliver capital expenditure below the level approved by the ERA as it is able to retain a portion of these savings. In addition, financial rewards and penalties under Western Power's Service Standard Adjustment Mechanism (SSAM) provide an incentive for Western Power to maintain or improve performance where the cost of doing so is less than the reward available under the SSAM.

The Code includes two capital investment tests, the Regulatory Test and the New Facilities Investment Test (NFiT). The Regulatory Test is applied prior to Western Power committing to network augmentations over specific cost thresholds. To meet this test, Western Power needs to demonstrate that the proposed network augmentation maximises the net benefit after considering alternative options such as demand side management or distributed generation. All capital expenditure, including augmentations subject to the Regulatory Test, is required to meet the NFiT before it can be added to Western Power's Regulated Asset Base. The NFiT is designed to ensure only efficient capital expenditure is passed through to customers and that expenditure is necessary to either maintain safety and reliability or delivers a net benefit or new revenue which is equal to the expenditure. At each access arrangement review the ERA determines whether Western Power's capital expenditure meets the requirements of the NFiT. Preliminary approval is given in relation to forecast expenditure with a final determination made at the next review when the expenditure has been incurred. Western Power is also able to request a determination in between access arrangement reviews in relation to specific projects.

Network businesses are heavily dependent on external funding to undertake capital works programs. With networks typically lasting between 40 to 50 years, debt (or equity) may not be paid down for a significant period of time. In Western Power's case its capital expenditure has significantly increased over recent years, with annual capital expenditure now currently averaging around $1 billion per annum. This significant capital works program has increased Western Power's dependence on debt as a funding source as demonstrated in Figure 13.

Figure 13: Western Power's net capital investment and total borrowings



Source: Western Power annual reports for each year and 2014-15 Budget extracts from WA Department of Finance and Treasury.

To provide additional context, over the five year regulatory period of Western Power's third Access Arrangement the ERA approved capital expenditure of approximately $6 billion (in nominal dollars).

The ability of a government to fund capital works is influenced by a broad range of factors, including budgetary constraints, the chosen fiscal policy (including the credit rating being targeted) and other whole-of-government priorities (for example, health and education). Consequently, a government may not always be able to afford required funding levels to deliver approved network capital expenditure or levels that the network provider views as necessary.

Western Power is currently experiencing such constraints as the state government seeks to improve its fiscal position and prioritises spending.

Western Power's approved Weighted Average Cost of Capital (WACC) (5.78 per cent nominal pre-tax) for its third Access Arrangement is significantly less than the WACC of network service providers in the NEM (determined by the Australian Energy Regulator (AER)). This is a contentious area. Some contend that the WACC in NEM jurisdictions is too high and has been a contributing factor to network "gold plating" and resulting higher network costs.[41] Similarly, some contend that the WACC in the WEM is too low and has challenged the ability of Western Power to make an appropriate rate of return on its investments. A lower WACC has a dual effect of lowering the cost of delivered electricity to customers but may dissuade investment in the network. The low WACC further entrenches the role of government in the electricity supply chain because it is reasonable to conclude that private sector capital would not invest in Western Australia when it can achieve a significantly higher rate of return in other markets.

Discussion question

A higher WACC would encourage network investment but could lead to an increase in network tariffs. Is this is a necessary trade-off to achieve a reliable network?

3.4 Fuel for future electricity generation

The outlook for generation fuels is an important part of the Electricity Market Review. We are concerned with the availability of fuel for future generation and the likely direction of future costs.

[41] Productivity Commission *Electricity Network Regulatory Frameworks – Productivity Commission Inquiry Report* Australian Government, 9 April 2013, pp. 66.

Gas Supply and Demand

Western Australia places a greater reliance on gas as an electricity generation feedstock than any other state. About 12 per cent of electricity generated in the NEM is fuelled by gas[42], as opposed to 42 per cent[43] in the WEM. This is unsurprising given Western Australia's abundant gas reserves, and the fact that the state's main actively mined coal fields near Collie in the south west are declining in quality and are progressively mining thinner seams at greater seam depth.

Proven offshore reserves of gas in Western Australia are estimated at more than 155,000 petajoules (PJ) or 140 trillion cubic feet (tcf).[44] In addition, the government estimates that "technically recoverable" unconventional onshore shale gas resources could be as high as 280 tcf.[45] These are estimated to be the fifth largest resources of shale gas in the world.[46]

The Western Australian domestic gas market consumes around 1,000 terajoules (TJ) of gas per day (or about 360 PJ a year).[47] As a comparison, Chevron, and its joint venture partners on the Gorgon project, have agreed to supply 2,000 PJ (or about 1.8 tcf) to the domestic gas market over the project's life.[48] The Western Australian domestic gas market is dominated by a handful of suppliers and buyers: up to 570 TJ/d is supplied by the North-West Shelf Gas Project (NWS) with the Apache Joint Venture from Varanus Island supplying up to 390 TJ/d.[49]

Domestic gas consumption represents approximately one third of all gas currently produced in the state.[50] By 2020 increases in LNG exports will halve this with the state consuming only about 10 per cent of all gas produced locally. Increases in LNG production will come from projects such as Gorgon and Wheatstone. Export LNG is more attractive than the domestic market for large gas projects given the size of export contracts and the prices that can be achieved. Current LNG prices are around $14/GJ with a netback price of $8 to $9/GJ compared to domestic prices being achieved of $7 to 11/GJ.[51] Western Australia has significant gas reserves as shown in Table 4.

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42 Australian Energy Regulator, *State of the Energy Market 2013*, p. 24.
43 IMO, *Electricity Statement of OpportunIties*, 2013.
44 Geoscience Australia, *Australian Gas Resource Assessment* 2012, pp. 1-2.
45 Department of Mines and Petroleum*, Petroleum in WA,* April 2014, p.4.
46 CSIRO, *Australia's Shale Gas Resources*, August 2012, p.1.
47 IMO, Op Cit.
48 *Barrow Island Act 2003 (WA),* Schedule 1, clause 17.
49 IMO, *Gas Statement of Opportunities*, January 2014, p.10.
50 KPMG/RISC, *Outlook for Fuels for Generation Draft Issues Paper*, May 2014, p.9, APPEA data.
51 Ibid, p.8.

Table 4: Summary of gas field developments

Basin Name	Project	Supply Status	2P Reserves @ 31 Dec 2013 (PJ)	2013 LNG Production MTPA	2013 Average Domestic Gas Production TJ/d
Carnarvon	NWS Varanus Devils Creek Macedon Pluto LNG	Existing	25,093	19.15	1,076
Perth	Red Gully/Gingin	Existing	103.6	-	24
Carnarvon	Gorgon Wheatstone LNG	Committed	57,100	24.5	500
Browse	Ichthys Prelude LNG	Committed	17,600	12.0	-
Carnarvon	NWS Gorgon P2 Wheatstone P2 Pluto LNG Scarborough	Potential	9,220	16.5	637
Browse	Browse LNG	Potential	16,650	12.0	-
Bonaparte	Bonaparte LNG	Potential	27,470	2.4	-
Browse	Poseidon Crux	Contingent Resource	Resource only >7000		

Source: RISC analysis

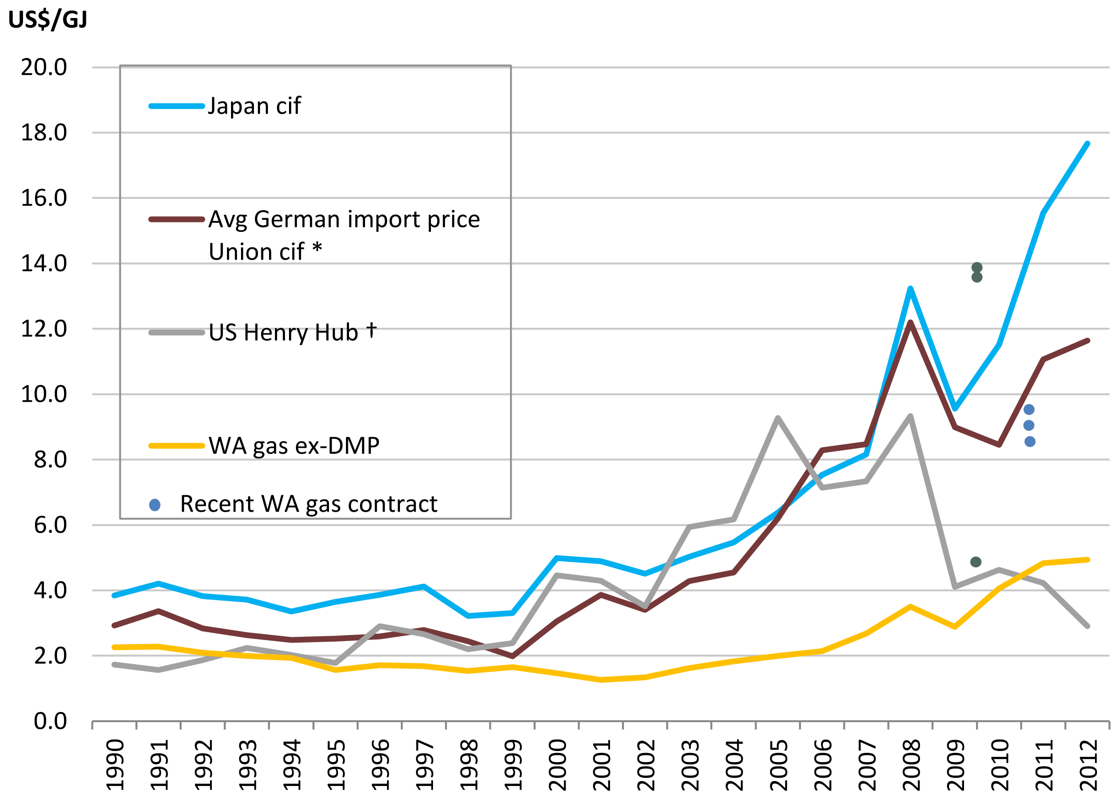
Many of the fields discovered in Western Australia's offshore basins have either been larger than 5 tcf, or resource owners have been able to aggregate this level of resources over a few fields.[52] In order to achieve acceptable rates of return from these very large offshore investments they need to achieve production rates of at least 500 to 600 TJ per day, equivalent to a one 4 million tonnes per annum (Mtpa) capacity LNG train. This level of daily production is approximately 50 to 60 per cent of the current Western Australian domestic gas market.

These 'lumpy' tranches of gas are not easily absorbed into a fully contracted domestic gas market, unless an existing large domestic gas contract expires or a new large gas customer load is established. But they can be relatively easily accommodated in the export LNG market. The development timetable of both smaller scale deposits suitable for the domestic market and larger scale LNG projects is long and ultimately cannot necessarily be timed to coincide with the expiration of sufficient domestic contracts to underwrite their development. From discovery to first production, field sizes of 1tcf for example could take a minimum of 5 years to develop for the domestic gas market, assuming an available market window of demand, and an LNG project could take a minimum 7 to 10 years.

As in other areas of the world, Western Australian gas prices are trending upward, as is shown in Figure 14. The dots on the chart represent recent new contracts signed, which are significantly higher than long-term legacy contracts, and thus higher than the current average Western Australian gas price.

[52] Geoscience Australia, *Op Cit*, p.15.

Figure 14: Historical global gas prices



Source: BP 2013, Department of Mines and Petroleum 2013, IMO

Longer-dated gas prices are also increasing, reflecting that international demand for LNG is pulling domestic prices higher, a factor compounded by rising exploration and development costs.

Synergy's cheaper legacy gas contracts, which flow from the contracts negotiated by the government with the NWS in the 1980s to underpin that project, have already begun to expire. Synergy has secured most of the gas needed to replace this contract, signing a deal with the Chevron-operated Gorgon project for 125 TJ per day, for 20 years commencing in 2015.[53] However, the ERA estimates that Synergy will pay up to triple its previous price for the new gas,[54] which will place upward pressure on electricity tariffs in future. Major oil and gas producers argue that the recent increase in domestic gas prices is, among other things, a function of rising exploration and funding costs and that those higher prices have had the desired effect of bringing new supplies to market.

The gas market outlook presents several implications for electricity generation.

Availability

There is no shortage of physical gas resources in Western Australia. However, the economics of field development for LNG as compared to the domestic market mean that domestic demand is still unlikely to get priority as new fields get developed and large gas contracts are secured. The size and expected growth of the domestic gas market is usually not large enough to capture a conventional gas field development and any unconventional resources, such as shale gas, are still only in the early stages of exploration and appraisal.

[53] Energy Minister Peter Collier, Western Australian Government Media Releases, *Wednesday, 30 November 2011*.
[54] ERA, *Inquiry into Microeconomic Reform in Western Australia Draft Report,* April 2014, p. 294.

There are no apparent resource availability or quality impediments to the reliable supply of natural gas to the Western Australian gas-fired generation sector. However, the commercial factors described above may result in gas production from large offshore projects being locked in LNG export contracts, lowering availability in the domestic market.

Price of gas

Recent developments in the domestic gas market give some indication that while there will be upward pressure on prices, they might not necessarily reach netback levels. The domestic gas reservation policy gives producers the choice of selling reserved gas in Western Australia now or later. This, and the commercial imperative to monetise reserves, means they may sell at less than netback prices if:

a) they have sufficient reserves to run the LNG trains at full capacity;

b) they have domestic gas plant with available capacity; and,

c) they can make an acceptable rate of return.

A high proportion of current supply has met these conditions, which is why LNG producers have reached agreement at prices significantly below netback in recent years. Even without the effect of the reservation policy it can make sense to sell domestic gas at below netback if the LNG trains are operating at capacity.

These factors indicate a gas price for future domestic electricity generation higher than that in the current legacy contract and, while market pressure will be towards netback price levels, a number of factors may mean that lower than netback for domestic gas could be achievable.

Discussion question

Do you consider that domestic prices will reach netback levels or some level below this?

Will there be sufficient gas reserves for future electricity generation needs?

How can the transparency and liquidity of the local gas market be improved?

How can new domestic gas supplies best be encouraged by downstream markets?

Coal supply and demand

About half of all electricity generated in the SWIS is fuelled by coal. The demonstrated resources of black and brown coal in Western Australia are 42,900 and 8,300 PJ respectively, while the inferred resources are 80,000 and 5,800 PJ respectively.[55] Western Australia has two coal producers – Yancoal and Lanco Resources (which acquired the Griffin coal mine in 2010). Both companies' mines are located at Collie in the south west.

Total coal sales in Western Australia have averaged about 7 Mtpa over the last five years. In 2011-12, the quantity of coal sold from Collie increased by 7 per cent to 7.5 Mtpa. The market for coal produced in the state is dominated by the power generation sector – coal consumption by coal-fired generators in 2014-15 is forecast to account for over 70 per cent of total sales to Western Australian domestic and export markets.[56]

Synergy is the main coal customer in Western Australia. It owns Muja A, B, C, D, Kwinana (multi-fuel), and Collie coal-fired power stations with over 1800 MW of generation capacity. Over the next 15 years, Synergy's coal consumption is estimated to be between 3.8 and 4.4 Mtpa depending on the utilisation of the existing coal-fired generation fleet. Synergy's coal consumption is expected to decrease by about 0.5 Mtpa following the retirement of Muja A and B plants.

[55] KPMG/RISC, Op Cit.
[56] Ibid.

The other major coal-fired power producer in Western Australia is the 416MW Bluewaters power station commissioned by Griffin Energy in 2009 and now owned by Sumitomo and Kansai Electric. Bluewaters' coal consumption is assumed to remain steady at 1.6 Mtpa; hence total coal consumption by the coal-fired generation fleet in the SWIS has been estimated at 5.4 to 6 Mtpa.

Outside of the generation sector, major industrial users of coal in Western Australia are:

- BHP Billiton Worsley Alumina refinery with an estimated coal consumption of 1.2 Mtpa;
- Cockburn Cement with a requirement of about 0.2 Mtpa; and,
- Mineral sands companies, Iluka and Tronox, each estimated to be consuming on average about 0.15 Mtpa.

In addition, coal is also sold in minor quantities to a number of small customers.

Limited tonnage is exported through the port of Kwinana with significant volatility of export sale volumes in recent years from 1.1 Mt in 2011-12 to just 0.1 Mt in 2013-14.[57]

In addition, Western Australia has significant estimated coal resources at 6.2 billion tonnes (Bt), comprising 930 Mt of economic demonstrated resources, 1.7 Bt of sub economic demonstrated resources and 3.6 Bt of inferred resources.[58] The locations of these resources are shown in Table 5.

Table 5: Coal resources in Western Australia

Basin	Description	EDR (Mt)	Total (Mt) [2]
Southern Perth	Collie, Ewington, Muja, Premier, Wilga, Boyup Brook and Vasse coal deposits.	930	2,232
Northern Perth	Eneabba, Irwin River, Saragon, Jurien and Eradu deposits	0	641
Canning	Fitzroy Trough coal deposits including Duchess-Paradise and Liveringa deposits	0	570
Carnarvon [1]	Includes Talisker deposit	0	0
Eucla	Salmon Gums, Scaddan, Balladonia and Zanthus deposits	0	2,776
Total		**930**	**6,219**

[1] Reliable resource estimates not available
[2] Includes: Economic demonstrated resources, sub-economic demonstrated resources and inferred resources
Source: Department of Mines and Petroleum

Collie coal is a low ash, low sulphur sub-bituminous coal, with low trace elements. It has a calorific value of about 20 megajoule per kilogram. By definition, sub-bituminous coals carry a relatively high moisture content, which lowers the energy of the product. The coal is well-suited for use in power generation and various industrial processes.

Western Australia has sufficient coal reserves in the Collie area of suitable quality to supply existing power generators and other existing domestic customers for over 40 years at the current rates of consumption. In addition, there are significant additional coal resources in the Collie area that may be developed, although the mining methods and the costs of production will require further examination.

[57] Fremantle Port Authority, *Trade Statistics*, June 2014.
[58] Department of Mines and Petroleum. *Resource Data Files* N.D Aavailable at: http://www.dmp.wa.gov.au/1521.aspx#1591 (accessed May, 2014).

There are no apparent resource availability or major quality impediments to providing a reliable supply of coal to the Western Australian coal-fired generation sector. However, there are some commercial concerns at present. Both of the Collie producers have publicly expressed concerns about the rising cost of their operations, compared with the long-term contract prices they are receiving for their coal. It is well known that the seams being worked are becoming narrower with more overburden to remove. If prices need to increase significantly it may be that other coal resources become competitive or, more likely for power stations in the region of the Collie mine, there is the possibility of coal imports from countries such as Indonesia. This would provide an effective cap for domestic prices at import parity levels.

Discussion question

Do you consider coal resources sufficient for future needs?

Other sectors of the mining industry have recently undertaken significant cost-cutting exercises. Is there similar need in the coal industry for greater efficiencies?

3.5 The future: more of the same?

The current high cost of electricity in the WEM is the major reason why Western Australian electricity tariffs are so high. These high costs have resulted in tariff increases for all customers despite the state government subsidising Synergy's operating costs by $495 million in 2013-14.[59] Overall subsidies to the industry as noted before (including Horizon Power) are more than $600 million. The level of tariffs and the required subsidy has the potential to increase in coming years. The current lack of competition in both the wholesale and retail electricity markets, combined with the RCM, mean that there are no competitive pressures to counter cost increases or indeed to lower some of the very high costs recently experienced in the generation sector.

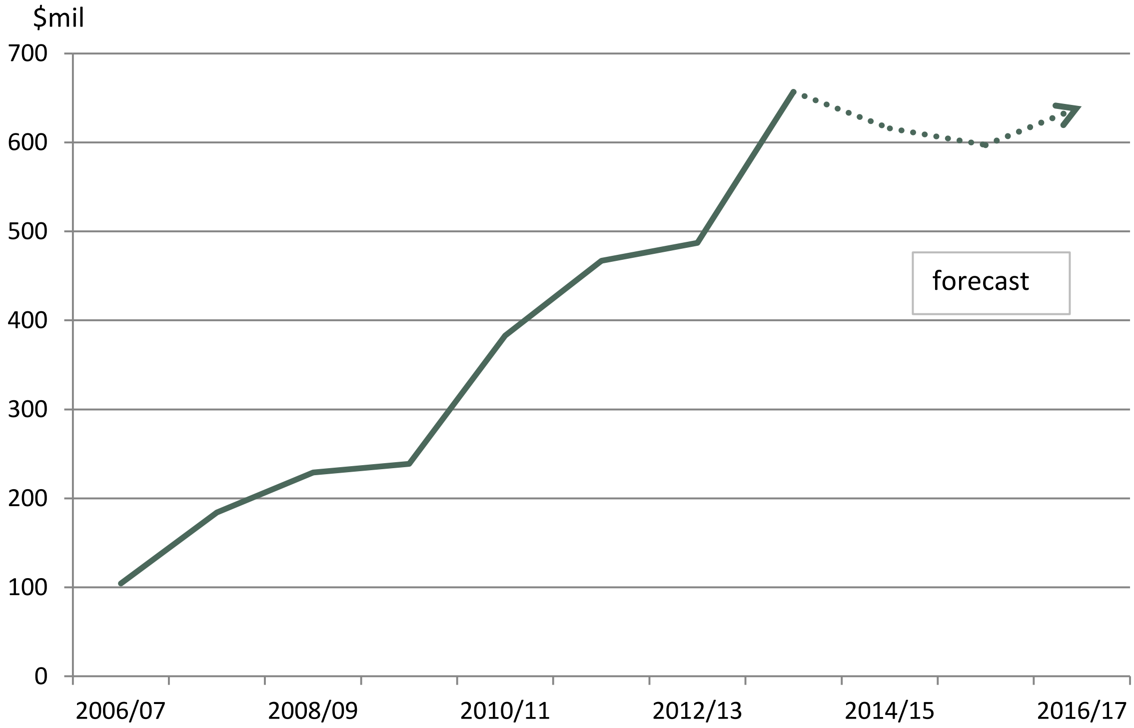
In the next four years the average cost of electricity in the SWIS is projected to increase potentially by about 20 per cent.[60] Short of any significant changes in the cost outlook or the expected trajectory of tariff increases relative to that announced by the government, the annual subsidy from the government will be over $600 million[61] – totalling over $2.4 billion in these four years on a business as usual case, as shown in Figure 15. This is a major impetus for reform in itself.

[59] Department of Treasury, 2014-15 Budget papers no. 3 (Economic and Fiscal Outlook) table 8.7. Available at: http://www.treasury.wa.gov.au/cms/uploadedFiles/State_Budget/Budget_2014_15/2014-15_bp2_vol2.pdf.

[60] Derived from Synergy budgetary submissions for 2014-15.

[61] Department of Treasury 2014 budget p. 603.Available at: http://www.treasury.wa.gov.au/cms/uploadedFiles/State_Budget/Budget_2014_15/2014-15_bp2_vol2.pdf (accessed 27 June 2014).

Figure 15: Subsidy to electricity customers



Source: 2014 budget, PUO data

Increases in tariffs for both domestic and industrial customers will also continue to erode the state's competitiveness and may constrain economic growth to levels below what could otherwise be achieved. While the next four years may see further increases in subsidies to customers, in the absence of reform the longer term outlook could be even more challenging. As we have discussed above, there will be upward pressure on both coal and gas prices and potential increases in network costs given asset replacement needs and the costs of servicing a peaky load profile.

Taxpayers currently underwrite 76 per cent[62] of capacity in the market either through direct ownership or bilateral contract commitments. Should the current industry structure and market mechanism remain, taxpayers will be required to fund the majority of new investment (network and generation).

Discussion question

What industry changes need to be made to reduce subsidies?

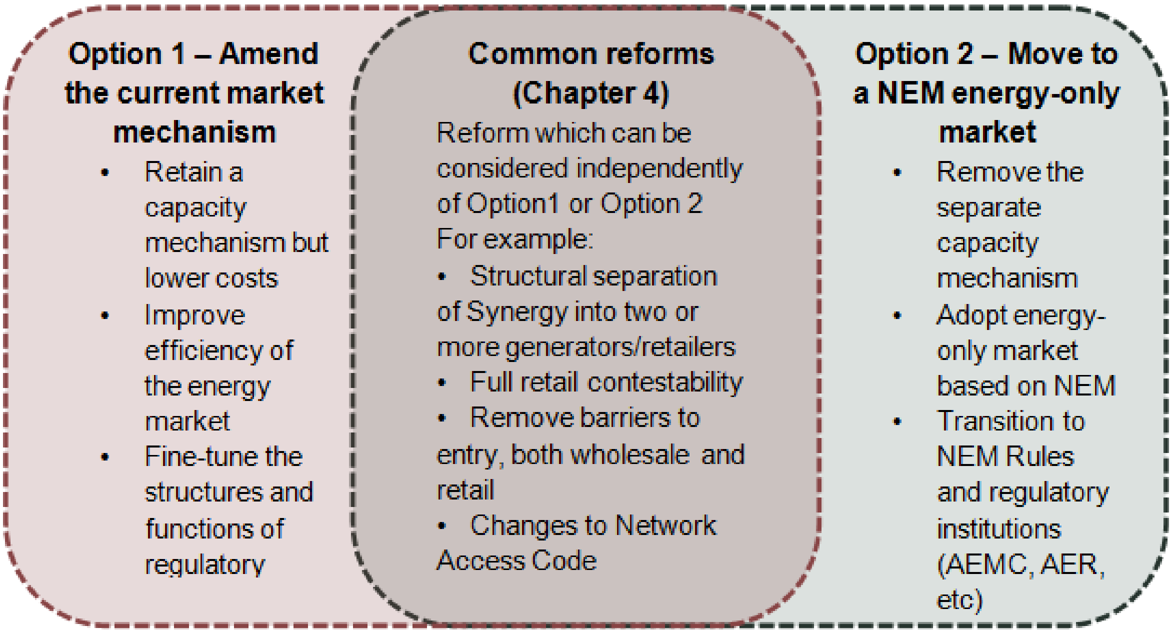
[62] PUO estimation of Synergy Individual Reserve Capacity Requirement.

4 Options: Industry structure and regulation

4.1 Introduction

This chapter and the next discuss some potential options for reform of the electricity industry in the SWIS which will address the underlying problems identified earlier in this Discussion Paper. The reform options being considered have been divided into two broad groupings. The first, considered in this chapter, concerns changes to industry structure and regulation. These are changes that appear necessary to allow competition and more transparent price setting in both the wholesale and retail markets. The second, considered in Chapter 5, concerns two broad options to change market mechanisms. The first option encompasses possible changes to the current WEM RCM and the STEM and balancing pool, whereas the second considers a move to a NEM energy-only market.

Figure 16: Reform options; industry structure and regulation



4.2 Encouraging competition in wholesale and retail markets

The WEM is a highly concentrated market with Synergy owning around 58 per cent of all installed capacity. Other major participants are Alinta, Griffin, NewGen, Vinalco and the Collgar wind farm. Synergy also holds a monopoly franchise covering all electricity customers with annual consumption of less than 50 MWh. This is around 6 terawatt-hours (TWh) per annum, or around 33 per cent of energy sold in the SWIS. Customers with consumption greater than 50 MWh per annum (around 66 per cent of energy sold in the SWIS) are contestable and are supplied variously by Synergy and other retailer participants. Synergy supplied approximately 10.5 TWh or 65 per cent of the energy sold in the WEM in the 2012-13 financial year.[63]

[63] Synergy data provided to PUO, unpublished.

Through bilateral contracts with generators, and capacity procured by the IMO, Synergy controls approximately 76 per cent[64] of the capacity credits assigned in the WEM market for the 2013-14 capacity year. The level of market concentration in the WEM, specifically the size of Synergy's generation portfolio, suggests that if the current Synergy structure is retained, the market is unlikely to deliver competitive outcomes under any market arrangement. This has been highlighted by the ERA[65] and in the arrangements that have been put in place in legislation covering Synergy, including ring fencing, transfer pricing, information restrictions and third party purchases and sales through standardised products.

The most effective solution to reduce market concentration is to structurally separate Synergy so as to increase the number of generators and retailers. The potential gains from structural separation would be reduced market power and improved allocative efficiency (i.e. electricity delivered at efficient prices that better reflected the cost of marginal supply at each point in time) leading to lower generation costs. Experience in the NEM in the 1990s and 2000s has shown that disaggregating dominant government owned portfolios of assets, including into a number of state-owned corporations, resulted in allocative efficiency gains from increased competition, which at the time outweighed any potential loss from economies of scale.

There would need to be careful consideration of the separation of assets and the way they might be packaged. The most benefit would likely be achieved if Synergy was to be separated into at least three generators and at least two retailers. The three generators would each have a base load generator as a core asset (Muja, Collie and Cockburn) as well as other peaking and intermittent plant.

The recent merger of Verve and Synergy would not be a setback in this regard. It has helped to reduce Synergy's costs and would be a step along this path if, for example, the assets were to be separated to form one or two gentailers as well as other independent generators and retailers.

In order for the competition benefits from structural separation to occur, the process must provide for full independence with respect to control and operation of the structurally separated assets. This would typically require the entities to be separately corporatised and operated under independent boards and preferably under different ownership.

Discussion questions

Do you see the structural separation of Synergy as important for achieving a competitive market?

Do you see regulating Synergy to mitigate its market power as a superior or inferior option to structural separation into two or three sets of assets?

Is the level of market concentration a matter of concern for existing and potential investors? Is it a factor in choosing to invest or not invest in the WEM?

4.3 Introducing full retail contestability

Retail market competition is important in ensuring that the benefits of a competitive wholesale market, particularly competitive prices for electricity generation, are passed through to customers. It also helps to minimise retailer margins and provide customers with choice, between both retailers and different types of products which better suit their needs.

The contestable customers are largely served by Synergy, Alinta, and Perth Energy. This is not surprising as the current market arrangements are more favourable to retailers that have strong links with generators through ownership or bilateral contracts. Contestable electricity customers served by each retailer in 2012 and 2013 are shown in Table 6.

Non-contestable electricity customers with an annual consumption below 50 MWh are supplied by Synergy under regulated tariffs. These tariffs are currently set well below the cost of supply

[64] PUO analysis of IMO data.

[65] ERA *Wholesale Electricity Market Report for the Minister for Energy*, 2013 p. 38.

and, as we have discussed above, they are subsidised by taxpayers.[66] This class of customers are usually attractive to electricity retailers as they provide a risk diversified customer base and tend to have higher margins. The lack of competition within this class of customers is a major factor in the lack of retail competition within the WEM as a whole.

Table 6: Contestable electricity customer numbers by retailer

	Residential		Non-residential	
Retailer	2012	2013	2012	2013
Alinta Energy	0	0	1,449	1,351
Perth Energy	0	0	68	171
Synergy	1749	333	7849	7173

Note: There are a small number of Synergy residential customers that are contestable.

Source: ERA, 2013 Annual performance Report – Energy Retailers

The method by which the TAP is paid will need to be changed before these customers could be made contestable. Market reforms discussed in this paper aimed at lowering generation costs could lower the need for the TAP and eventually allow its removal. If a subsidy is to be retained, at least during a transition period, it would need to be made available to all retailers competing for those customers. This may be achieved by paying the subsidy to the network business, rather than Synergy, which is able to pass it on to all customers regardless of their retailer. Or, it could be assigned to the customer and moved to a new retailer when the customer moves. The former is likely to be less expensive to administer than the latter and, perhaps, easier to phase out in response to cost improvements.

The ERA, in its final report into Synergy's efficient costs, argued that the TEC should no longer be met by SWIS customers as it "is not an efficient cost that is associated with generating, distributing or retailing electricity in the South West. It is a levy that is imposed on electricity customers in the South West, on the basis of a government policy decision".[67] The ERA recommended it be funded from consolidated revenue and the Steering Committee agrees that there is merit in this approach if trying to achieve tariffs that reflect efficient costs.

In the NEM, competition for dual fuel customers has been strong as retailers seek to sell both electricity and gas.[68] In Western Australia the gas market is fully contestable in principle. However, Synergy is unable to compete for small gas customers because of the Gas Market Moratorium[69] and so in practice the gas market is also not fully contestable in terms of residential customers.

[66] Annual cost of supply subsidies were estimated by the ERA at $371 million in 2012-13 and are expected to rise in subsequent years. This does not include the additional subsidy costs associated with the Uniform Tariff Policy which is primarily aimed at equalising tariffs for non-SWIS customers.

[67] ERA *Final Report for the Inquiry into the Efficiency of Synergy's Costs and Electricity Tariffs* 2012 p.10. Available at http://www.erawa.com.au/economic-inquiries/completed-energy-inquiries/efficiency-of-synergys-costs-and-electricity-tariffs (accessed 27 June 2014).

[68] Retailers compete for dual fuel customers because of scale benefits and also because dual fuel customers are considered to be more loyal.

[69] Synergy is unable to compete for residential gas customers with annual consumption less than 180 GJ as a consequence of the Gas Market Moratorium.

Table 7: Contestable gas customer numbers by retailer

	Residential		Non-residential	
Retailer	2012	2013	2012	2013
Alinta Energy	628,328	624,314	8,468	8,355
Synergy	0	0	112	141
Wesfarmers	535	8,212	1	20
Worley Parsons	279	296	31	36

Source: ERA, 2013 Annual performance Report – Energy Retailers

It is clear from this retail market data that effective retail market competition is very limited.

A market in which entrants are active and the threat of new entry is significant would generally be considered a competitive market. There is little evidence of this in the SWIS. There are measures that would assist in this process:

- Allowing full competition for small electricity customers would increase the attractiveness of the market to both existing and new entrant retailers; and,
- Repealing the Gas Market Moratorium to allow the restructured Synergy entities to compete for small gas customers and provide dual fuel offerings in competition with others.

Discussion questions

In moving to a market that can accommodate FRC, how should the TAP and TEC be handled?

What factors need to be considered in the repeal of the Gas Market Moratorium?

Should the TEC continue to be funded from SWIS distribution tariffs, or instead be funded from consolidated revenue?

4.4 Improving incentives for efficient investment in networks

As discussed earlier, the unconstrained network access model does not fully promote economically efficient electricity supply. It creates a potential barrier to competition, and may be adding to the long-term cost of supply by providing greater reliability than customers are willing to pay. However, past experience suggests generators have not been prepared to fund deep network connections, and the Western Power has moved towards a hybrid constrained-unconstrained network model through the use of runback schemes and lower redundancy in certain new developments.

Western Power has a monopoly over the provision of network and metering services in the SWIS, however, there are aspects of these operations that could be exposed to competitive pressures. Providing a framework for competition in the provision of metering services has the potential to facilitate higher service quality and greater accountability. In addition to potentially providing meter services more cost efficiently than the incumbent, competition also provides greater opportunity for the varying needs of customers to be met by innovative metering solutions while also reducing the financial burden on government to fund metering infrastructure.

It may also be possible to allow third parties to tender to solve particular network constraints at the lowest cost. Although Western Power tenders for third parties to deliver particular solutions, allowing third parties to tender solutions of their own might encourage more innovative solutions to network constraints. Examples of such solutions are battery storage to solve for voltage fluctuations at the distribution substation level, or distributed generation backed up with storage to defer augmentation of distribution and even transmission infrastructure.

Discussion Questions

Should the network operator be subject to competition in the provision of metering and other services?

Should the WEM adopt the NEM access regime?

4.5 Addressing fuel cost pressures

The illiquid nature of the state's gas market may be a barrier to entry for new private sector generation. On the supply side, the major suppliers of gas to Western Australian firms operate in joint ventures. The North West Shelf and Gorgon joint ventures both operate under a competition law waiver from the Australian Competition and Consumer Commission (ACCC) which enables them to jointly market domestic gas until the end of 2015.[70] On the demand side, more than 90 percent of gas is bought by a handful of companies under long term gas contracts, such as Alcoa, Alinta Energy, BHP Billiton, Burrup Fertilisers, Citic Pacific and Rio Tinto and Synergy. Timing mismatches are a significant problem. At any one point in time there are very few market participants either marketing gas for sale or seeking long term gas contracts on the demand side. This makes it difficult for new potential entrants.

Given the relatively small size and high concentration of the Western Australian domestic gas market, an efficient gas trading market is important for both buyers and sellers of gas to achieve efficient short- and medium-term gas pricing. Reflecting a non-formal market, there exists two active short-term gas trading markets in Western Australia, one operated by gasTrading Pty Ltd, which accounts for about 1 per cent of daily gas use, and the other by Energy Access Services (EAS). These are markets which are used to trade imbalances in participants positions.

In the NEM the Australian Energy Market Operator (AEMO) created market facilities and rules for the Gas Supply Hub during 2013. The Gas Supply Hub is an electronic trading platform that utilises standardised terms and conditions with a market settlement facility that supports the short-term trading of physical gas and related products.

The Gas Supply Hub was established with products for the sale and purchase of gas delivered at one of the three major connecting pipelines at Wallumbilla in Queensland which complements existing bilateral gas supply arrangements and gas transportation agreements. The Gas Supply Hub enhanced the fungibility and liquidity of the gas market to better enable participants to allocate and price gas efficiently.

Discussion questions:

Would there be material benefit in establishing a gas supply hub in Western Australia? How should it be implemented?

[70] A review will be undertaken by the ACCC to see if this arrangement should continue into the future.

5 Options: Market mechanisms and institutional arrangements

5.1 Introduction

We have considered two options for a market mechanism for the WEM. Option One is based on developing the current WEM market mechanism and attempting to improve several of its mechanisms to overcome the problems identified in this Discussion Paper. This approach would keep the same market institutions, the IMO, the ERA and System Management, as well as the broad characteristics of the current model. But it would attempt to reduce the costs of capacity added through the RCM and the transparency and relevancy of the pool and the prices set by it.

Option Two involves a movement of the SWIS to the NEM regime. If a NEM gross pool were adopted, the most cost effective and rational way to do this would be for Western Australia to join the NEM and adopt its Rules. This would include rules covering the operation of the market, transmission, distribution and retail.

5.2 Option One: Amend the current market mechanism

Potential changes to the RCM

Move from an administratively-derived capacity price to an auction mechanism

An alternative to the current RCM could be an auction, or a series of rolling auctions. This would allow capacity credits to be efficiently priced by creating competition in the price setting process. The IMO could run one or more auctions for capacity for each capacity year. The maximum amount of capacity purchased under auctions should be limited to the Individual Reserve Capacity Requirement (IRCR). It may also be desirable to impose a price cap on the auction equivalent to the current administratively determined price of capacity.

An auction approach, if competitive, would allow the capacity price to be set at a level reflecting any supply surplus or shortfall of capacity. A successful auction would require reasonable levels of competition to be successful and there may be a question as to whether there are enough participants and enough diversity of ownership in the WEM to allow a competitive process. It may also be possible to carry out additional auctions for DSM with different price caps for different levels of availability.

There would still need to be a requirement for capacity to be certified by the IMO to be able to participate in the auctions and also for an incentives and penalty regime to ensure that capacity was available at the times when it is most valued by the market.

Move the responsibility for procuring capacity to market participants

Another option for reform, and complementary to the auction approach, is to restrict the IMO's role in procuring capacity and impose the obligation on retail market participants to source their own capacity. The obligation would include the requirement to cover supplied demand plus a reserve margin. This could include capacity sourced through longer term bilateral contracts and shorter term capacity traded by participants. The obligation would most likely be placed on buyers.

This approach would be expected to stimulate a secondary market in capacity as participants sought to match capacity obligations with energy acquisitions. This market could be left to develop naturally or could be sponsored by the IMO.

The IMO could be required to certify capacity of companies that wished to participate. Alternatively it could maintain the right to review or inspect capacity that was offered to ensure that it met minimum standards to participate. The IMO would also be required to track the obligations of each participant and manage the remittance of capacity "tickets" by participants to cover those obligations. This would have some administrative cost associated with it.

Discussion questions:

Would one or more IMO auctions for capacity, in which only capacity to meet the Reserve Capacity Requirement was acquired, produce more competitive prices for capacity?

Are there alternative methods for lowering capacity acquisition costs that should be considered?

Making the existing WEM more efficient

Introduce facility bidding for all participants

At present, Synergy is treated differently to all other market participants under the Market Rules. It is able to bid into the market as a portfolio, rather than by facility or unit. This is a hang-over from the time when Verve Energy was required to be the default provider of balancing services. With the advent of the competitive balancing market, the rationale for portfolio bidding is largely redundant. Facility, or preferably unit by unit bidding, would enhance the function of the economic dispatch in the market and make price setting a much more transparent process.

If Synergy bid by facility like other market participants, it would provide greater transparency to the relative costs (including short run marginal cost) of each of Synergy's generation assets. This would improve the competitiveness of the market, and would result in greater consistency in how market participants are treated under the Market Rules.

Reduce gate closure

When originally conceived, the NEM was designed to operate two and one day-ahead short term markets. The experiences of participants in the Victorian and New South Wales markets, which were precursors of the NEM, led to these short term markets being scrapped.

Many markets operate with a gate closure lock-out period after which participant bids or changes to schedules are not accepted. Gate closures typically have two purposes. The first is to limit the opportunity to exercise market power and collude in response to real time conditions. The second is related to response times in system management; i.e. allowing time for participant changes to be reflected. United States markets typically have a one hour gate closure, Singapore's is 65 minutes and in the United Kingdom it is 30 minutes, and New Zealand's is two hours. However there is considerable discussion in New Zealand with respect to shortening the gate closure – one of the main benefits is more consistency between dispatch and pricing.

The NEM operates in real time with no gate closure. Dispatch operates on a five minute basis with half hourly prices being the average of six, five minute prices. Participants may make changes to bids within a few seconds of a dispatch period starting – the only limiting factor is the ability of system control to include such changes. However, there are rules governing bidding behaviour including the requirement to provide a reason for the rebid and the time it occurred.[71]

The NEM approach is based on creating transparency so that inappropriate behaviour or collusion, if it was to occur, would be visible to all parties. If the STEM and Balancing Markets were folded into a single market that operated close to real-time, the gate closure might also be minimised or possibly removed to assist in achieving the same goal.

While not strictly part of the Balancing Market, the WEM also operates a load following ancillary service (LFAS) market which Synergy must bid to supply and in which other participants may participate. A number of electricity markets have incorporated load following or frequency control and contingency reserve services which are co-optimised with the energy market. It would appear feasible to consider introducing dynamic and co-optimised LFAS in the WEM.

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[71] National Electricity Rules Version 62, clause 3.8.2.2(c). Available at http://www.aemc.gov.au/energy-rules/national-electricity-rules/current-rules (accessed 27 June 2014).

Encourage fungibility of energy contracts and tools for market participants to manage risk

The majority of all energy sales within the SWIS are conducted through bilateral contracts. Figure 5 shows that over the past three years 95 to 110 per cent of energy traded in the SWIS is traded via a bilateral contract. These tend to be bespoke agreements over long time frames and based around specific power projects or power plants. Bespoke contracts are not easily traded as they tend to incorporate specifically negotiated clauses which make them in part or as a whole not fungible.

The two exceptions to the above are the major electricity retailers, Synergy and Alinta, which are vertically integrated and transfer electricity between the generation and retail segments of their businesses as they see fit, although both also engage in bilateral contracting with other market participants.

Under the status quo, any new entrant retailers would need access to bilateral contracts with generators (or build their own plant) to be able to compete. In addition, the ability to manage risk in financial terms is a major factor for potential investors in electricity markets.

There are a range of methods for managing financial risk including commodity contracts or hedging contracts and insurance. Most well-functioning electricity markets include markets for making and transacting electricity commodity or derivative contracts with residual low probability but high cost events managed through insurance products. Conditions for the development of workable commodity and derivative contracts usually include:

- an adequate level of wholesale market competition;
- an adequate number of buyers and sellers;
- a mature and reasonably robust set of underlying trading arrangements;
- consistency between market price and market demand or dispatch;
- risk being linked to performance; and,
- the delivery and pricing of all major products and services through the market (to minimise or avoid external management of market functions and associated uplift payments).

The WEM is a relatively small and highly concentrated electricity market and the current industry structure does not appear conducive to the development of sophisticated financial risk management. If such risk management products are required some form of institutional or regulatory intervention may be required to assist their development if they do not develop naturally. The New Zealand Electricity Authority did this successfully with marked increases in hedge transactions in the New Zealand electricity market over the last three years.

There are several options for market intervention, including:

- sponsoring standardised bilateral contract forms and encouraging trade in these contracts through mandatory requirements on large participants to make markets;
- establishing futures contracts with the assistance of the Australian Stock Exchange (ASX) and encouraging trade through mandatory requirements on large participants to make markets;
- expanding the standard products regime imposed on Synergy as part of the merger to create a voluntary market for all participants to be able to trade small, standardised parcels of energy; and,
- setting requirements on large participants to anonymously report over the counter (OTC) hedge transactions (volume and price) to create price discovery and transparency (futures transactions are automatically transparent and reported).

Discussion questions:

What benefits could be realised by requiring Synergy to bid on a facility-by-facility or unit-by-unit basis?

Would co-optimisation of ancillary services and energy markets be beneficial? Would it assist participants in offering more capacity to either or both markets?

Would a transparent and liquid contract market be of benefit to generators and retailers?

Improving the operation of market institutions

Changes to the Rules

In the NEM, the Australian Energy Market Commission's (AEMC) roles are limited principally to rule making and market development. The AEMC cannot itself propose rule changes. However, it can be asked by governments to conduct reviews and to recommend associated rule changes. AEMO, in its role as market and system operator, can also propose rule changes for consideration by AEMC but is not able to make rules. In the WEM, the IMO has the ability both to propose and to make rule changes and, in practice, most rule changes proposed by the IMO are accepted by the IMO.

As the IMO operates the wholesale electricity market it has a detailed practical knowledge of how the rules work in practice. But it also has a vested interest in the form and content of rules made. Separating rule proposing from rule-making in the WEM would address the risk, or perception of risk, of vesting too much power with one entity. The IMO is well placed, and should be able, to propose rule changes to better achieve market objectives. But there is likely to be a more widely supported process and outcome if the rule change was considered and decided upon by another body.

This body could be the Public Utilities Office or the ERA, although if either of these bodies took over the responsibility of rule changes they should then be precluded from proposing changes to the market rules themselves.

System Management

Many other electricity markets (including the NEM and North American markets) have separated system management from transmission ownership to enable multiple owners of transmission assets to work with a single system operator.[72] In the NEM, the system management function is grouped with the market operation function performed by AEMO. An independent Reliability Panel[73] was also established to monitor, review and report on the safety, security and reliability of the national electricity system.

The New Zealand electricity system has similar structural arrangements to Western Australia in that Transpower owns the transmission network and is the system operator. New Zealand also has established an independent Security and Reliability Council[74] which provides independent advice to the Electricity Authority[75] on the performance of the electricity system and the system operator, and reliability of supply issues.

While there is only one network service provider in the SWIS there would not appear to be a strong argument for changing the current arrangement whereby System Management is part of Western Power. Given the need for it to act independently and closely with the IMO there may be a case for changing its governance arrangements so as to strengthen its independence and accountability by, for example, establishing a reliability panel, setting clear performance standards, and establishing performance monitoring arrangements could assist with this. These could be modelled on the NEM or New Zealand arrangements.

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[72] Michael G Pollitt, *Lessons from the History of Independent System Operators in the Energy Sector, with applications to the Water Sector*, EPRG Working Paper 1125, Cambridge Working Paper in Economics 1153 August 2011, p.4.

[73] *National Electricity (South Australia) Act 1996*, s.38.

[74] The Electricity Authority must appoint a Security and Reliability Council - New Zealand Electricity Industry Participation Code 2010, section 7.3(2).

[75] The Electricity Authority is an independent Crown entity responsible for the efficient operation of the New Zealand electricity market.

Discussion questions:

Are the current rule change assessment arrangements appropriate? Do you think it would be better to have the rule change process undertaken by a body other than the market operator?

Are there any systemic problems affecting System Management's performance? Is there a case for changing its structural or governance arrangements?

5.3 Option Two: Move to a NEM gross pool market

Western Australia as a region of the NEM

Option two involves the introduction of a NEM-style gross pool in the WEM. This would be a significant change in the underlying design of the market and would result in major changes to the current energy market arrangements. Conceptually the NEM design and systems could be adapted and utilised in the WEM, including the existing legislation, rules and processes and market operation. However, by far the most efficient process would be to adopt the NEM Rules, regulation and institutions and become a non-connected region of the NEM.

This would involve adopting all sixteen chapters of the National Electricity Rules, the most important being:

- Chapter 3, Market Rules on the operation of the pool, generator offers, the price setting and settlement process;
- Chapter 5, Network Connection, Planning and Expansion;
- Chapter 5A, Electricity Connection for Retail Customers;
- Chapter 6, Economic Regulation of Distribution Services;
- Chapter 6A, Economic Regulation of Transmission Services;
- Chapter 6B, Retail Markets; and,
- Chapter 7, Metering.

There would be an opportunity for Western Australia on entering the NEM to include derogations – that is, departures from the Rules that are specific to a particular jurisdiction or market participant. All other signatories to the Rules have included derogations as part of their entry and it would be open to the Government of Western Australia to do the same. They might involve, for example, the way Western Australia's reserve margin is calculated given that it is a region that is unconnected to the rest of the NEM, as well as transition arrangements involving regulation of bodies such as Western Power and the handling of legacy obligations to market participants.

The major benefit of moving to such a system is that it has been successfully operated since 1998 with successive fine tuning through Rule changes and amendments to market institutions to address many of the issues arising now in Western Australia. The NEM is transparent and competitive in its price setting. Wholesale generation prices are reflected in contracts between generators and retailers and in retail tariffs, which is not happening in the SWIS.

The Western Australian region of the NEM would be a gross pool. This means that all electricity that is generated must be offered through the pool. Some exceptions would apply for embedded and "behind the fence" facilities. The pool would be settled four weeks in arrears with maximum exposure at any time being around 35 days of purchases. Market customers, the participants that purchase energy from the pool, either to retail to customers or for their own use, would be required to lodge prudential instruments or equivalent with the market operator to cover the likely worst case costs for these purchases.

Based on the NEM design, the gross pool would operate essentially in real-time with the market operator sending dispatch instructions to plant and setting prices on a five minute basis (the dispatch interval). Variations in supply and demand within the five minute dispatch interval would be managed through ancillary services which would also be traded in real-time. Energy and ancillary services would be co-optimised. Pricing would be based on half hour trading intervals with prices set as the average of the six five minute dispatch.

The adoption of the NEM and its rules and institutions would not be possible without the disaggregation of Synergy. The generation assets would need to be separated potentially into three asset bundles and the retail business could also be separated geographically. Matching some generation assets with retail areas would assist both wholesale and retail competition and help retain the benefits of the recent vertical merger between Synergy and Verve. Without the horizontal separation of these assets the market would not be competitive. It would require Synergy assets to meet demand on too many occasions, thereby ceding market power to a single generator. A gross pool market mechanism relies on some volatility and occasional high prices in time of day and seasonal prices that can cover both long run and short run generator costs. Capping prices in order to control market power would negate these market signals and a managed capacity mechanism would be required in lieu of them. This would be the same as the current mechanism operating in the WEM.

Real time dispatch and pricing

In the NEM generators are free to submit bids at any price within the range set by the floor (-$1000/MWh) and the market price cap (currently $13,100/MWh but adjusted annually). Initial bids must be submitted on the day prior to dispatch but there is no gate closure for rebidding – the limit is simply a system limit and is typically less than one minute.

The Western Australian NEM pool is likely to be more volatile than the STEM and the Balancing Market. Volatility is usually managed through secondary market derivative contracts (swaps, caps, collars, etc.). The most common contract used is a two-way hedge, or swap, which involves the generator protecting a retailer or other buyer against a higher price than the contract strike price and the retailer protecting the generator against a lower price. Another common contract is the one-way hedge, or cap contract. This means the generator shields a buyer against prices over a certain level and receives a fixed premium for doing so. Once hedging arrangements are put into effect, participants would be expected to have relatively low levels of exposure to the pool price volatility.

Market customers in the NEM (typically retailers) might hold swap contracts covering around 95 per cent or more of their physical requirements and may cover the remainder with caps or other derivative contracts so as to limit their risk. Generators typically hedge 75 to 90 per cent of their capacity with the remainder held in reserve to help manage situations in which plant within their portfolio is unavailable because of a forced or planned outage.

Participants would require new IT systems to allow them to bid in the form required by the energy market and to capture data to support trading and risk management. Well established systems already exist in the NEM and we believe they could be acquired at relatively small incremental costs.

Remove marginal cost limitations on generator bidding, market prices to signal new investment requirements

Energy markets are designed to allow competitive forces to drive outcomes and send the appropriate price signals to demand and to potential entrants. This means that generator bidding can’t be limited to short run marginal cost as energy prices need to fluctuate according to shortfalls or oversupply of capacity in the market to appropriately signal new investment requirements.

Gross pool markets such as the NEM are not well suited to markets that are concentrated or where there are high degrees of market power. As an example, the England and Wales Pool suffered from a dominant duopoly between National Power and PowerGen. Prices between 1989 and 1998 were well above entrant levels. While this brought forward significant volumes of gas fired entrants (the so called dash for gas), the duopoly maintained significant influence on prices. This situation ended around 1998 when National Power and PowerGen agreed to divest significant coal fired power stations as part of an agreement which allowed them to vertically integrate by purchasing retail businesses. Wholesale prices fell well below entrant levels following these divestments largely as a consequence of the increased competition. As we have mentioned above, the NEM gross pool would not be a feasible option unless Synergy assets are structurally separated into more generators and retailers.

No capacity mechanism, although a safety net reserve trading mechanism may be retained

A NEM gross pool market by definition has no centrally planned capacity mechanism. The NEM currently has a Reliability and Emergency Reserve Trader (RERT) function vested in AEMO. It is due to expire in June 2016 but may be extended. The RERT allows AEMO to contract for capacity no more than nine months into the future where AEMO is of the view that reliability will fall outside the accepted standards. The RERT contracted capacity is unable to participate in the market for the periods that it is contracted.

The Reliability Standard is set by the Reliability Panel, made up of industry and jurisdictional representatives. The Standard, which is an unserved energy standard applying over the long term, has been met so far in all NEM regions. The Reliability Panel also defines the principles that AEMO must follow if it considers that the RERT might need to be used. The RERT has not been used by AEMO since the start of the NEM.

In a WEM gross pool market, it might be prudent to extend the RERT or a similar mechanism until there is evidence that the market is operating as intended and creating suitable incentives for new investment to ensure long-term reliability and security of supply. This might be included as a derogation in the Rules for the SWIS on the basis of the region’s isolation from the rest of the NEM.

Development of risk management tools – secondary markets for electricity hedges

A secondary market in contracts would be required for participants to manage risk. There are concerns as to whether a liquid contracts market would develop naturally in a market the size of the SWIS. Using an approach such as that used in the New Zealand electricity market to promote trading in contracts might have benefits. This approach would require major participants to offer an agreed volume or proportion of their portfolio as hedges through futures or OTC markets to underpin trading in the hedge markets.

Investors use forward contract markets to identify when the market might be able to support entry of additional generating plant and, to a lesser extent, to identify when to shut plant. Typically contracts trade in the NEM two to three years in advance, although liquidity tends to be thin towards the end of that period.

Discussion question:

Should facilitated contracting be a design feature of a NEM gross pool in the SWIS?

Regulation of the Western Australian region of the NEM

The regulation of networks would be moved to the AER, which would regulate the application of the Rules on access to both the transmission and distribution networks as well as the tariffs applicable. The network access Rules in the NEM apply constrained access and shallow connection charges for new entrants. There would be a number of transitional issues to be addressed here, including the treatment of current unconstrained access rights and the application of AER economic regulation. This would include the WACC parameters the AER uses rather than the ones applied by the ERA. The NEM Rules for governing the process for deciding on new investment to reduce or remove network constraints and network expansion would also apply.

In some cases the changes would be significant and it would take Western Power and the regulator some time to adapt the current processes applied to network access and tariff setting. These changes would need to be managed through a transition period as different access rules and procedures were put in place and different levels of access rights carried over.

Access to the retail market would also change, allowing multiple retailers access to the same market and the unlimited transfer of customer data, including meter readings, between competing retailers. While the retail and metering chapters of the Rules (6B and 7) would apply, tariffs would continue to be set by the government, or economic regulation of tariffs could be transferred to the ERA. We would expect tariff regulation to be maintained over a transition period during which TAP and TEC were phased out and the retail market moved toward FRC with, preferably, only price monitoring rather than regulation.

Changes to Market Rules would be handled on a national basis by the AEMC. The state government would negotiate any particular rules and derogations it might see as necessary in protecting the interests of the state and its electricity customers.

Market management and system control would be undertaken by AEMO. While not necessarily part of AEMO, system control would be contracted, and would report, to them.

Discussion questions:

What do you consider the most important matters to be managed in a transition to the NEM?

Are there any matters that you would see as the subject of Western Australian derogations to the National Rules?

How long would it take to transition to a NEM gross pool for the SWIS?

Appendix 1 - Glossary

AA3	Western Power's current Access Arrangement
ACCC	Australian Competition and Consumer Commission
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
ASX	Australian Stock Exchange
Bt	Billion tonnes
CSO	Community Service Obligation
DSM	Demand Side Management
EBR	The Energy Board of Review
ERA	Economic Regulation Authority (WA)
ERTF	Electricity Reform Task Force
FRC	Full Retail Contestability
GJ	Gigajoules
IMO	Independent Market Operator
IRCR	Individual Reserve Capacity Requirement
IT	Information Technology
LFAS	Load Following Ancillary Services
LNG	Liquefied Natural Gas
MRCP	Maximum Reserve Capacity Price
Mt	Million tonnes
Mtpa	Million tonnes per annum
MW	Megawatt
MWh	Megawatt Hours
NECF	National Energy Customer Framework
NEM	National Electricity Market
NFiT	New Facilities Investment Test
NWS	North West Shelf
OTC	Over the Counter
PJ	Petajoules
PJM	The Pennsylvania-New Jersey-Maryland Interconnection, a Regional Transmission Organization in the US Eastern Interconnection Grid
PUO	Public Utilities Office
RCM	Reserve Capacity Mechanism
RERT	Reliability and Emergency Reserve Trader
SAPN	South Australian Power Network
SECWA	State Electricity Corporation of Western Australia
SRMC	Short Run Marginal Cost
STEM	Short Term Electricity Market
SWIS	South West Interconnected System
TAP	Tariff Adjustment Payment
tcf	Trillion Cubic Feet of gas
TEC	Tariff Equalisation Contribution
The Code	Electricity Network Access Code
TJ	Terajoules
TJ/d	Terajoules per day
TW	Terawatt
WACC	Weighted Average Cost of Capital

Appendix 2 – Terms of Reference

Phase 1 will identify the strengths and weakness of the current industry structure, market institutions and regulatory arrangements and develop options for reforms to better achieve the Electricity Market Review Objectives:

Phase 1 will comprise two stages.

Stage 1 – Strengths and weaknesses of current industry, market and regulatory arrangements

Stage 1 will consider whether the current industry structure, market institutions and regulatory arrangements facilitate achievement of Electricity Market Review Objectives. This will include consideration of the following matters.

- The parameters of industry structure, market institutions and regulatory arrangements and the behaviours of parties within the industry and market that have contributed to increases in costs of electricity services since disaggregation of Western Power Corporation in 2006.
- The strengths and weaknesses of the current industry structure in achieving the Electricity Market Review Objectives, having regard to:
  - the past industry-entry and activity of private sector investors and retailers
  - the outlook for future entry of private investors and retailers into the industry under current industry and market arrangements
  - the past business activities and business practices of the state-owned electricity corporations active in the South West Interconnected System
  - the Verve Energy – Synergy Merger and the regulatory framework to be put in place to limit potential for anticompetitive behaviour.
- The strengths and weaknesses of the current Wholesale Electricity Market in achieving the Electricity Market Review Objectives, having regard to:
  - the fundamental design of the Wholesale Electricity Market as a capacity-plus-energy market
  - the design and practical functioning of the capacity market
  - the design and practical functioning of energy-trading arrangements, including bilateral contracting arrangements, the Short-Term Energy Market and the Balancing Market.
- The strengths and weaknesses of the current regulatory arrangements for the electricity sector in achieving the Electricity Market Review Objectives, including:
  - the institutional arrangements and performance of the bodies involved in the regulation of the electricity sector including the Public Utilities Office (formerly the Office of Energy), Energy*Safety*, Independent Market Operator, System Management and Economic Regulation Authority

- the regulatory framework for network access under the *Electricity Networks Access Code 2004*, and the practical outcomes of this framework in securing network access and enabling investment in generation
- the regulatory framework for consumer protection; and
- the processes for amending regulatory instruments (including the Market Rules and related Codes, the Electricity Networks Access Code and consumer protection instruments) and the governance of these processes.

- The constraints and opportunities on industry participants arising from the characteristics of markets for primary fuels (coal and gas) in the South West of Western Australia.
- Any perceived barriers to entry to the Western Australian electricity market by large generation, networks and retail businesses active in the National Electricity Market.

Relevant inputs to Stage 1 include:

- Past reviews of the operation of the Wholesale Electricity Market, such as the Economic Regulation Authority's annual Wholesale Electricity Market Report to the Minister for Energy.
- Past investigations of industry structure, including the 2009 Verve Energy Review.[76]
- Past investigations of costs of electricity supply services, in particular the Public Utilities Office's final report on the drivers of increases in costs of electricity services in the South West Interconnected System.[77]
- The Independent Market Operator's past and current work program for the development of the Wholesale Electricity Market.[78]
- A paper prepared by the Merger Implementation Group for the Verve Energy – Synergy merger on issues in the Wholesale Electricity Market that need to be addressed as a result of the merger of Verve Energy and Synergy to facilitate:
  - continued operation of the wholesale electricity market;
  - sustained private-sector investment in the electricity sector.
- The regulatory framework to be established to limit potential for anti-competitive behaviour by the Merged Verve Energy – Synergy business.[79]
- Australian and international developments in electricity markets and market design.

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[76] Deloitte – Oakley Greenwood, *Verve Energy Review*, August 2009.

http://www.imowa.com.au/f2875,2115624/VerveEnergyReview.PDF.

[77] Public Utilities Office, *Drivers of Increases in Costs of Electricity Services in the South West Interconnected System*, Final Report, August 2013 (pending publication).

[78] Independent Market Operator, Market Rules Evolution Plan: 2013-2016, November 2012.

http://www.imowa.com.au/f5592,3200469/Market_Rules_Evolution_Plan_2013-2016_FINAL.pdf

[79] Regulations are to be enacted before 31 December 2013 to allow commenced of the merged business on 1 January 2014.

Stage 2 – Options for industry and market reform

Stage 2 will define at a high level a set of options for reform of the industry structure, the wholesale electricity market and the regulatory and institutional arrangements that will better facilitate the Electricity Market Review Objectives. The purpose of stage two is to develop a range of options for reform, and to make recommendations for preferred options.

Options for reform should be developed having regard to the following matters.

Industry structure – Develop options for a competitive and commercially-viable generation and retail industry structure required to:

- establish the conditions necessary to attract major energy companies into the Western Australian electricity market
- establish the conditions necessary to enable future major generation to be built by the private sector without government support or underwriting of investment by state-owned retail businesses
- protect, to the extent consistent with the Electricity Market Review Objectives, the value to the state of the currently state-owned electricity businesses and the assets of these businesses.

A range of generation and retail elements should be examined in developing options for industry structure including:

- gentailers
- merchant generation
- specialist retail businesses
- on-going participation in the market of state-owned businesses, either as stand-alone businesses or in partnership with private-sector participants.

Primary fuels market – identify opportunities and options for reform of coal and gas markets that are required to address any constraints that these markets present to achieving the Electricity Market Review Objectives.

Wholesale Electricity Market design – Develop options for reform of the fundamental design of the Wholesale Electricity Market including:

- considering whether the Electricity Market Review Objectives might best be achieved by a capacity-plus-energy market or energy-only market
- if a capacity market were to be retained, then options for reform of the capacity market such that the security objectives of a capacity market are achieved at least cost
- if an energy only market may support the Electricity Market Review Objectives, then the high level design features of an energy-only market
- if major changes to the capacity market were to occur or an energy-only to be developed, the potential options for transition to a significantly different market design.

Network access – Develop options for reforms to the regulatory arrangements for network access, including consideration of:

- “constrained” and “unconstrained” models of network access for generators

- potential benefits of greater alignment of the access regime with the access regime of the National Electricity Market.

Retail electricity market – Develop options for reforms to the retail electricity market, addressing:

- retail contestability thresholds;
- mechanisms for regulation of retail electricity prices;
- arrangements and mechanisms for concessions and subsidies
- the regulatory framework applying to the electricity retail market, for instance, in relation to metering, customer transfer arrangements and customer protection.

Institutional structures – Develop options for reforms to the institutional and regulatory structures for the electricity sector, including in relation to:

- the organisation arrangements for System Management and the Independent Market Operator and whether there are benefits to change of the current arrangements where System Management exists as part of the network business and the Independent Market Operator as a separate statutory entity
- the policy advice and regulatory functions of the Public Utilities Office
- the policy advice and regulatory functions of Energy*Safety* as they relate to the electricity sector and electricity market
- the process for amending the Market Rules and the governance of this process
- the functions of the Economic Regulation Authority and whether regulatory functions should continue to be undertaken by a Western Australian regulatory agency, or whether some functions might better be undertaken by the Australian Energy Regulator.