Government of **Western Australia**
Department of **Finance**
Public Utilities Office

Position Paper: Design Recommendations for Wholesale Energy and Ancillary Service Market Reforms

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Glossary

Term	Definition
Ancillary services	A group of services that is required to maintain the security and reliability of a power system and ensure that electricity supplies are of an acceptable quality.
Balancing	The process of adjusting the output of generators to maintain the balance between power system supply and demand, but excluding the automated small-scale adjustments made by generators providing load following.
Commitment	The decision of whether and when to start a generator.
Constrained network access model	A model for the provision of access to an electricity network under which generators compete through the wholesale market for access to the network to deliver energy to consumers.
Constraint (or network constraint)	A limit on the flow of electricity through a particular element of the network. The limit is used to maintain power system reliability and security, for example by preventing the overload of network equipment or ensuring there is sufficient capacity to recover from the unexpected failure of a transmission line.
Co-optimisation	The practice of determining the overall least-cost dispatch outcome for energy and ancillary services concurrently.
Dispatch cycle	The frequency at which dispatch instructions are issued, which covers both when dispatch instructions are generated and the period over which they apply. Currently in the Wholesale Electricity Market dispatch instructions are issued: • ten minutes before the half-hour, for the first ten minutes of that half-hour; • five minutes after the start of the half-hour, for the second ten minutes of that half-hour; and • fifteen minutes after the start of the half-hour, for the last ten minutes of that half-hour.
Dispatch instruction	An instruction issued to a market participant by the system operator to move the output of its generator (or consumption of its load) to a prescribed level (measured in MW) at a prescribed ramp rate.
Dispatch interval	The time period for which dispatch instructions are calculated.
Ex-ante pricing	Prices that are established by the market clearing engine consistent with the dispatch instructions issued by the system operator, immediately before a dispatch interval.
Ex-post pricing	Prices that are calculated after the event from actual supply and market offers and actual system demand.
Gate closure	The deadline for changes to generator offers into a market for a given dispatch interval.

Term	Definition
Independent power producer	A market participant, other than Synergy, that owns, controls or operates a generator connected to the South West Interconnected System.
Intermittent generator	A generator that cannot be dispatched to a specific MW level because its output level is dependent on factors beyond the control of the operator (for example wind).
Interruptible load	A load that can reduce its consumption automatically if the system frequency falls below a set level.
Load following	An ancillary service provided by a fast-responding generator or load to maintain the system frequency under normal circumstances. The generator (or load) is required to adjust its output (or consumption) up or down in response to instructions received every four seconds. (This ancillary service is known as regulation in the National Electricity Market.)
Load rejection reserve	The ancillary service provided by a generator that can reduce output rapidly in response to a sudden increase in the system frequency (usually caused by a sudden decrease in system load). (This ancillary service is known as contingency lower in the National Electricity Market.)
Market clearing engine	A sophisticated software application that integrates generation, demand and network data to determine the least cost dispatch of energy and ancillary services, used to generate dispatch instructions and prices for a real-time electricity market.
Merit order	A list of generator offers to an electricity market (usually in the form of MW quantities with associated prices) ranked in order of increasing price.
Net bilateral position	The total quantity of energy sold to other market participants under bilateral arrangements for the trading interval, less the total quantity purchased from other market participants under bilateral arrangements for the trading interval.
Out-of-merit dispatch	The dispatch of generators other than in accordance with the relevant merit order, so that more energy is dispatched from a more expensive generator and less energy is dispatched from a cheaper generator.
Ramp rate	The rate at which a generator changes its output level, usually measured in MW/minute.
Runback scheme	A scheme that automatically curtails the output of a generator in response to a network trigger, such as the power flow on a particular transmission line exceeding a set value.
Security-constrained market design	A wholesale electricity market design in which network constraints are taken into account in the determination of dispatch schedules and energy prices.

Term	Definition
Short Term Energy Market (STEM)	A day-ahead market operated by the Australian Energy Market Operator, in which market participants can buy and sell energy for the following trading day to adjust their net bilateral positions. The market is purely financial and does not affect the real-time dispatch of generators.
Spinning reserve	The ancillary service of holding the capacity of a generator or interruptible load in reserve, so that the facility can increase its output (for a generator) or decrease its consumption (for an interruptible load) rapidly in response to a sudden decrease in system frequency (usually caused by the sudden failure of a generator). (This ancillary service is known as contingency raise in the National Electricity Market.)
Trading interval	A period of 30 minutes commencing on the hour or half-hour. In the Wholesale Electricity Market participant offers are submitted, and settlement outcomes calculated, for each trading interval.
Unconstrained market design	A simple wholesale electricity market design in which the effect of network constraints is ignored in the determination of dispatch schedules and energy prices.
Unconstrained network access model	A model for the provision of access to an electricity network under which the network is built and operated to ensure that generators that connect under standard access contracts have full access to the network under normal operating conditions.

Executive Summary

There is a need for major reform to address material inefficiencies in the provision of energy and ancillary services in the Wholesale Electricity Market and to improve transparency and competition. This position paper outlines the Electricity Market Review's proposed reforms to the energy and ancillary service operations and processes.

The current market systems and processes are unable to ensure the efficient, transparent and least-cost dispatch of generators while maintaining the security of the system. The physical limitations of the transmission network are not accounted for in pre-dispatch market processes or in the automated dispatch system, which have been designed on the assumption that network congestion will only occur rarely. Manual intervention is required to manage network congestion when it occurs, but the slow speed of such manual processes hinders further efficiency improvements to the market design.

The current market design and systems will become unworkable as the frequency of network constraints increases. Western Power and System Management have indicated that the continued use of existing systems and processes to support the entry of new generators and manage network congestion in real time will not be feasible. Western Power is currently processing numerous network connection applications for new generators and has advised that these connections will greatly increase the frequency and materiality of binding constraints. In addition, the adoption of the constrained network access model within the national framework for network regulation would streamline the connection process for new generation projects and would therefore be expected to result in further material increases in the frequency of binding constraints.

Reforms to the energy and ancillary services markets in the South West Interconnected System are essential for three primary reasons:

- to create opportunities for efficiency improvements that can reduce costs for customers;
- to ensure that system security can be maintained without sacrificing market efficiency as the operation of the power system becomes increasingly complex; and
- to harmonise the market operations and processes in the South West Interconnected System with other reforms arising from the Electricity Market Review, including the adoption of the national framework for network regulation of the Western Power network, the transfer of retail market operations to the Australian Energy Market Operator and full retail contestability.

There are three essential, core features of the proposed reforms, which are a common feature of other competitive electricity markets:

- the adoption of a security-constrained market design;
- facility bidding for all market participants; and
- co-optimisation of energy and ancillary services.

The adoption of a security-constrained market design will be essential to maintain power system security as network congestion increases. It will also improve market efficiency by increasing transparency, providing better quality forecasts to market participants and also providing information on the locations where new capacity or network investment will deliver greatest value to consumers.

A transition to facility bidding for Synergy is essential to achieving security-constrained market dispatch. While facility bidding will involve additional costs for Synergy, it is expected to provide Synergy with greater control and flexibility to optimise the operation of its power stations, and to deliver wider efficiency benefits for the market.

The co-optimisation of energy and ancillary services is expected to deliver substantial efficiency benefits for the market through determining the overall least-cost dispatch for both energy and ancillary services, as well as reducing risk for market participants and promoting greater competition. Given the size of Synergy's generation portfolio and its dominance in the provision of ancillary services, co-optimisation is also essential for facility bidding by Synergy to be operable and efficient. The establishment of new markets for spinning reserve and load rejection reserve would expose these services to competition and likely place downward pressure on ancillary service costs over time.

To complement these reforms, it is proposed that later gate closure and a shorter dispatch cycle are adopted to deliver considerable efficiency benefits and lower costs for consumers. Later gate closure better informs decision-making by market participants through the provision of more timely and accurate information closer to real-time. It is proposed that a common gate closure be adopted for both the energy and ancillary services markets, to be applied to all market participants. A shorter dispatch cycle allows the use of more accurate forecasts and more frequent dispatch instructions so that the energy market can better match supply to fluctuating demand, reducing the burden on ancillary services. It is conservatively estimated in this position paper that the benefits of later gate closure and a shorter dispatch cycle would exceed $100 million in present value terms.

The Electricity Market Review proposes that the Australian Energy Market Operator's National Electricity Market Dispatch Engine (NEMDE) system is utilised in the implementation of the proposed reforms. NEMDE performs security-constrained co-optimised dispatch of energy and ancillary service markets, and represents a relatively simple and low-cost solution for implementing the proposed reforms. The Electricity Market Review has considered the use of more sophisticated, off-the-shelf systems to implement the proposed reforms, but considers that the benefits of such systems are unlikely to outweigh the material benefits of a NEMDE-based implementation in terms of simplicity, familiarity, cost, risk and speed of implementation.

A series of supplementary changes to market operations and processes are also proposed that will generally provide for closer alignment with the National Electricity Market, while taking into account factors specific to the South West Interconnected System and the Wholesale Electricity Market, including the Reserve Capacity Mechanism.

The Electricity Market Review proposes retention of the Short Term Energy Market (STEM) provided that the cost to retain it is not excessive. The STEM makes energy available at reasonable prices and with relatively low transaction costs, and incorporates market power mitigation measures (including mandatory offering of spare certified capacity) that alleviate concerns about the competitiveness of the market structure in the South West Interconnected System. The Electricity Market Review has not found an alternative forward market design that appears able to provide all these features under the current market structure.

In the longer term, as the market structure becomes more competitive, the Electricity Market Review envisages various forward markets could develop according to the needs of market participants. Such markets, which could develop outside of the formal Wholesale Electricity Market, could supersede the STEM, providing an opportunity to abolish it. The likely future abolition of the STEM weakens the case for substantive modification to these arrangements in the short term.

No fundamental changes are proposed to the current market power mitigation measures. However, refinements are proposed to reflect specific design features of the new real-time markets and to provide greater clarity regarding the obligations of market participants.

The proposed reforms provide a practical, fit-for-purpose solution that addresses the problems identified in this position paper and supports the objectives of the Electricity Market Review. The new market design would allow the Australian Energy Market Operator to leverage its systems, processes and expertise but would also be tailored to account for the operation of the Reserve Capacity Mechanism and other Wholesale Electricity Market-specific needs. The design aligns with and supports other proposed Electricity Market Review reforms in the areas of market competition and network regulation.

The proposed reforms would leave the Wholesale Electricity Market well-positioned from a longer-term, strategic viewpoint. The new market design addresses the most urgent energy and ancillary service concerns, but excludes larger changes that would require major financial commitment down a path that diverges substantially from the National Electricity Market. The proposed reforms do not lock the Wholesale Electricity Market into a particular long-term development path, giving future policy makers the freedom to monitor market developments and, in the longer term, select the best development option for Western Australia – whether this involves retention of the proposed arrangements, further enhancements to manage the growth of new technologies or a full transition to the National Electricity Market.

The market reforms are targeted to take effect on 1 July 2018 to align with the commencement of the national framework for network regulation and changes to retail market operation. Implementation will require strong involvement from the Australian Energy Market Operator, with close coordination of detailed design of market operations and processes, drafting of amendments to the Wholesale Electricity Market Rules, and design and implementation of information technology system changes.

The proposed reforms outlined in this position paper are discussed at a relatively high level. The implementation phase will include a detailed design process to decide on the mechanisms and supporting arrangements for required reforms to registration, forecasting, pre-dispatch, dispatch and settlement processes.

Market participant involvement will be vital during the implementation phase of the project. It is expected that one or more working groups will be convened to inform the detailed design process, review rule drafting and to assist market participants in the practical steps required to prepare for the new market arrangements. It is also acknowledged that a lengthy period of market trials will be needed to allow for testing of systems and interfaces and ensure a smooth transition to the new market arrangements.

Submissions from stakeholders are invited on the proposed reforms in this position paper by no later than 27 April 2016. While specific matters on which submissions are sought are identified throughout this paper, submissions need not be limited to these items. Information on how to make submissions is set out in Chapter 9 of this position paper.

The Electricity Market Review will take written submissions into account in the preparation of an implementation proposal, which is scheduled to be provided for government consideration by June 2016. The implementation proposal will also be informed by cost estimates from the Australian Energy Market Operator for the development and implementation of new market and dispatch systems. Costs that may be incurred by market participants as a result of the proposed changes are also requested for this purpose.

1. Introduction

This position paper proposes reforms to improve the efficiency and transparency of the energy and ancillary service markets in the South West Interconnected System. It has been prepared for the Energy Market Operations and Processes project as a part of Phase 2 of the Electricity Market Review.

Reforms to the energy and ancillary services markets in the South West Interconnected System are essential for three primary reasons:

- to create opportunities for efficiency improvements that can reduce costs for customers;
- to ensure that system security can be maintained without sacrificing market efficiency as the operation of the power system becomes increasingly complex; and
- to harmonise the market operations and processes in the South West Interconnected System with other reforms arising from the Electricity Market Review, including the adoption of the national framework for network regulation of the Western Power network, the transfer of retail market operations to the Australian Energy Market Operator and full retail contestability.

The reforms being considered by the Energy Market Operations and Processes project, and described in this position paper, are expected to yield efficiency improvements and to improve the transparency and predictability of market outcomes, consistent with the objectives of the Electricity Market Review. These changes are expected to drive efficiency benefits exceeding $100 million in value[1] and will also increase the competitiveness, dynamism and automation of the energy and ancillary service markets and processes.

The objective of this first stage of the Energy Market Operations and Processes project is to develop an implementation proposal to be provided to the Minister for Energy by June 2016, to seek approval to proceed to implementation. This implementation proposal will include the primary design recommendations for the energy and ancillary service markets, estimates of the costs and benefits of the recommended reforms and a high-level plan and time estimate for implementation.

The purpose of this position paper is to set out, and seek stakeholder feedback on, the rationale, options and preferred high-level design for the proposed energy and ancillary service markets, to inform the implementation proposal. The position paper details:

- the need for reform;
- the core elements of the proposed reform package;
- the rationale for alignment with the National Electricity Market;
- features of the proposed design;
- proposals in respect of market power mitigation measures;
- assessment of the proposed reforms against the Electricity Market Review objectives;

[1] In present value terms. This estimate is likely to be conservative as the Electricity Market Review has not attempted to quantify all of the benefits. See Chapter 3 for further information on the benefits of the proposed reforms.

- considerations for the implementation of the proposed reforms; and
- a description of the consultation process for this position paper and future stages of the Energy Market Operations and Processes project.

Other reforms being progressed by the Electricity Market Review – particularly changes to network regulation and the Reserve Capacity Mechanism, and the implementation of full retail contestability – may have consequential effects on the final design of the energy and ancillary service markets. Reforms in these interconnected aspects of the market are being considered in a unified manner. Preliminary consideration is given to these matters in this position paper, noting that they will be considered in further detail during the implementation phase of the project.

Submissions from stakeholders are invited on the proposed reforms described in this position paper. While specific matters on which submissions are sought are identified throughout this paper, submissions need not be limited to these matters. Information on how submissions can be made is provided at Chapter 9.

2. The need for reform

The design of the Wholesale Electricity Market has evolved markedly since the market commenced in 2006, enabling increased competition and delivering efficiency improvements.

However, inefficiencies in the provision of energy and ancillary services remain. It is estimated that these inefficiencies may be costing consumers millions of dollars per year. In the absence of reform, it is likely that these costs would escalate in the future and potentially form a barrier to future investment.

In addition, limitations concerning the transparency and predictability of the energy and ancillary service mechanisms present barriers to competition and impede the optimal delivery of these services.

This chapter describes the areas where reform is required.

2.1 Unconstrained market design

In electricity markets, a constraint is a limit on the flow of electricity through a network. Constraints are used to maintain power system security, for example by preventing the overload of network equipment or ensuring there is sufficient spare capacity to recover from the unexpected loss of a transmission line. A network is said to be suffering from congestion when a constraint restricts the supply of electricity to loads or affects the dispatch of generators. In these situations the constraint is said to ‘bind’.

The current Wholesale Electricity Market arrangements are premised on an unconstrained market design. The market design assumes that electricity flows from generators to loads are unrestricted, with each generator able to output to its maximum capacity without threatening system security under normal network operating circumstances (i.e. with no major transmission lines out of service). Simple cost-based merit orders for generator dispatch are developed without any consideration of network constraints.

In addition, the automated dispatch systems used by System Management do not automatically account for network limitations. When congestion does occur, System Management must manually intervene and dispatch generators ‘out-of-merit’ (dispatching more energy from a higher priced generator and less energy from a cheaper generator) to alleviate the constraint.

This misalignment between the network and the energy market results in various inefficiencies, including:

- a lack of transparent and timely information – forecast dispatch plans can be unreliable as they ignore the effects of congestion, discouraging active competition in the real-time markets;
- deficiencies in the current compensation mechanism for out-of-merit dispatch, which has been designed on the basis that constraints bind infrequently and only for short durations, and may under-compensate a generator that is constrained on for an extended period;

- potential higher long-term costs to consumers, as the constraint payment mechanism is not sufficiently transparent to provide a long-term price signal to new entrants to locate their projects where they would deliver the greatest value; and
- the requirement for extensive manual intervention to manage congestion, which increases the operational burden on System Management and the likelihood of errors or inefficient dispatch.

The market design reflects the current unconstrained network access model for the South West Interconnected System, under which the network is built and operated to ensure that generators who connect under 'reference' access contracts have full access to the network under normal operating conditions. A new generator seeking a reference access contract is expected to contribute to the costs of any network upgrades needed to ensure its access entitlement. The costs of these upgrades can be extremely high, in the order of hundreds of millions of dollars.

To avoid high network upgrade costs, Western Power and project developers have over recent years agreed to 'non-reference' access contracts based on the installation of 'runback schemes'. A runback scheme automatically curtails the output of a generator in response to a network trigger, such as the power flow on a particular transmission line exceeding a set value. About 25 runback schemes currently operate in the South West Interconnected System, operating on a post-contingent basis (i.e. following the outage of one or more transmission lines).[2] Runback schemes have been subject to criticism on the basis that they lack transparency and can interfere with the efficient, least-cost dispatch of generators.[3]

Constraints already bind regularly in the South West Interconnected System, including as a result of network outages. For example, in some areas such as the North Country[4], regular out-of-merit dispatch has been necessary since market start, while the network has suffered several extended periods of congestion in recent years due to work on the Mid West Energy Project and the transformer failures at Muja.

Western Power is currently processing numerous network connection applications for generators through its Competing Applications Group process, with scheduled connection dates within the next three years.[5] Advice from Western Power indicates that the connection of these new generators will greatly increase the frequency and materiality of binding constraints, including in pre-contingent conditions (i.e. in the circumstance when all network assets are in service).

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2 Public Utilities Office, *Electricity Market Review Discussion Paper*, 25 July 2014, p.28, available at: http://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/electricity-market-review-discussion-paper.pdf.

3 For example, Independent Market Operator, *IMO Submission to Electricity Market Review Discussion Paper*, September 2014, p55, available at: http://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/Independent-Market-Operator.pdf.

4 The 2014-15 Annual Planning Report defines the North Country load area as extending "from Pinjar and Muchea at the northern edge of the Neerabup terminal load area to Kalbarri at the northern extremity of the Western Power Network". Document available at http://www.westernpower.com.au/documents/2014-15_annual_planning_report.pdf, p35.

5 Western Power has indicated that the applications predominantly relate to renewable generation facilities, incentivised by the Commonwealth Government's Renewable Energy Target.

Western Power and System Management have indicated that the continued use of runback schemes to support the entry of new generators will not be feasible. The existing runback schemes have been implemented with bespoke systems that operate independently of each other, without regard for other network constraints – consequently, this solution is not scalable as the level of constraints increases and greater coordination is required. Western Power has investigated alternative dispatch tools to facilitate these connections[6], however none appear able to provide adequate transparency of market conditions and deliver economically efficient outcomes.

When considering the market arrangements, an unconstrained market design is only workable if the level of network congestion is very low. An increase in the frequency of constraints will render the current unconstrained market design unworkable, as the market would be increasingly misaligned with the practical realities of the network.

Consequently, the adoption of a security-constrained market design (that includes consideration of network constraints in the calculation of dispatch schedules) is essential for the South West Interconnected System. This necessitates replacement of the market and dispatch systems currently used by the Australian Energy Market Operator and System Management to operate the Wholesale Electricity Market, as these systems will be incapable of managing the security of the network as the frequency of constraints increases over time.

Further, as part of Phase 2 of the Electricity Market Review, progress is being made towards applying the national framework for regulation of Western Power's transmission and distribution network from 1 July 2018. This includes the adoption of a constrained network access model, which requires generators to compete through the wholesale market for access to the network to deliver energy to consumers, removing the current expectation that all generators will have unconstrained physical network access under normal operating conditions. The implementation of a constrained network access model would streamline the connection process for new generation projects and would be expected to result in an increase in the frequency of binding constraints, reinforcing the need to adopt a security-constrained market design.

Security-constrained markets are described in further detail in section 3.1.

2.2 High load following costs

Load following ancillary services (known as regulation in the National Electricity Market) provide the primary mechanism to ensure that energy supply and demand are balanced in real-time. Load following resources must have sufficient ramping capability to adjust output to match system load between scheduling steps in order to maintain the system frequency. Load following can only be provided by generating units operating under Automatic Generation Control.

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6 For example, the Network Constraint Tool referred to in Western Power's application to the Economic Regulation Authority for an exemption to the Technical Rules with respect to the connection of the Byford solar farm. Application available at: https://www.erawa.com.au/electricity/electricity-access/western-power-network/technical-rules/era-determinations-on-exemptions-from-the-technical-rules/byford-pv-solar-farms

Load following costs are relatively high in the Wholesale Electricity Market, compared to those in other markets.[7] Recent data provided by System Management indicates that ancillary services cost around $63.3 million for the year ending March 2015, with load following representing more than 70 per cent of this cost.[8] In comparison, the total cost of ancillary services in the National Electricity Market over the same period was around $98 million, with load following (regulation) representing only about six per cent of this cost.[9] Although total energy consumption in the Wholesale Electricity Market is about one-tenth of that in the National Electricity Market, the cost of load following is more than seven times greater in the Wholesale Electricity Market.

Load following costs are to some extent affected by the physical characteristics of the South West Interconnected System (for example its isolation, small size and small number of generators) and the characteristics of the generation fleet (such as fuel mix). This means that the unit cost of load following in the Wholesale Electricity Market is likely to remain above that of larger, more interconnected markets. These costs are however still higher than what should be achievable if changes were made to the market design. Analysis of the contributing factors has found that several of the largest contributors are linked to deficiencies in the current market design, as discussed below.

- Early gate closure for the load following market, up to 11 hours ahead, combined with the lack of co-optimisation[10] with the balancing market, means that market participants are unsure of their costs (which depend on balancing market outcomes) at the time they finalise load following offers. Consequently, participants are likely to include a material risk margin in these offers[11] or opt out of providing load following services.
- The comparatively long dispatch cycle in the Wholesale Electricity Market[12] increases the magnitude of forecast errors at the time of issuing dispatch instructions and hence increases the load following requirement. This is because load following compensates for system demand and intermittent generation forecast errors, and the larger these errors the larger the load following requirement and associated costs.
- Under current dispatch arrangements, generators are always instructed to ramp towards their target output levels at their maximum nominated ramp rate. This ramp rate may be much faster than is necessary for balancing supply and demand, resulting in an excess or shortfall of energy within the interval (depending on whether the generator is ramping up or down), with any differences being met using load following. The present 30-minute dispatch cycle in the Wholesale Electricity Market amplifies these excesses

7 2014 Ancillary Service Standards and Requirements Study, available at http://wa.aemo.com.au/home/imo/consultations/2014-ancillary-service-standards-and-requirements-study

8 Western Power (System Management), *Ancillary Services Report 2015*, 12 August 2015, available at http://wa.aemo.com.au/home/electricity/market-information/system-management-reports

9 Based on data available at http://www.aemo.com.au/Electricity/Data/Ancillary-Services/Ancillary-Services-Payments-and-Recovery.

10 Co-optimisation refers to the practice of determining least-cost dispatch for energy and ancillary services concurrently, to improve dispatch efficiency. Balancing and load following are not currently co-optimised in the Wholesale Electricity Market, with gate closure for the load following market occurring three hours before balancing market gate closure for non-Synergy generators (six hours before for Synergy).

11 A risk margin may be explicit (an uplift in offer prices to account for risk) or implicit (e.g. the use of conservative input assumptions when forecasting operating costs and hence offer prices).

12 The current Wholesale Electricity Market design incorporates a 30-minute dispatch cycle, with generators issued dispatch instructions to move to target output levels for the end of the upcoming 30-minute dispatch interval. This compares with the five-minute dispatch cycle used in more sophisticated electricity markets.

or shortfalls and hence the load following requirement, compared to what would occur with a shorter dispatch cycle.

- The manner in which the Synergy portfolio is dispatched (discussed in detail in section 2.4) blurs the boundary between the balancing and load following markets, as the same generators are used by System Management for both services. This approach makes it impossible to precisely measure the quantity of load following capacity that is being used, which in turn appears to contribute to an overly conservative procurement of load following quantities, given that recent frequency performance for the South West Interconnected System exceeds the standard prescribed in Western Power's Technical Rules by two orders of magnitude.[13]

Achieving reductions in load following costs requires that these deficiencies be addressed through a combination of later gate closure, a shorter dispatch cycle, co-optimisation of energy and ancillary services, and changes to the manner in which the Synergy portfolio is dispatched. These changes are discussed in Chapter 3.

2.3 Competition in ancillary services

Aside from load following, the current Wholesale Electricity Market design provides only limited opportunities for alternative providers to compete with Synergy to provide ancillary services. Currently, spinning reserve and load rejection reserve[14] are procured from either Synergy as the default provider or through a contract between System Management and another participant. Payment to Synergy for these services is determined through an administered price calculation, while prices for contracts with other parties are required to be lower than the price paid to Synergy.[15] The contracting opportunities for other parties are limited as they are usually required to provide the relevant service at all times, at a price lower than the administered price paid to Synergy.[16]

Retaining Synergy as the sole (or dominant) provider of ancillary services was a pragmatic option when it controlled around 90 per cent of generation capacity in the South West Interconnected System in the early stages of the Wholesale Electricity Market.[17] However, as more competitors have entered the market, some of which have the capacity to provide ancillary services, there are likely to be long term economic benefits in exposing these services to competition.

Furthermore, market participants have expressed interest in greater competition in ancillary services, voting for the introduction of a competitive spinning reserve market as the fourth

[13] Western Power (System Management), Ancillary Services Report 2015, 12 August 2015, available at http://wa.aemo.com.au/home/electricity/market-information/system-management-reports.
The Report indicated that frequency was maintained between 49.8 and 50.2 Hz for more than 99.99 per cent of the time for the 12-month period to April 2015. This exceeds the requirement of 99 per cent stipulated in Table 2.1 of the Technical Rules.

[14] Spinning reserve and load rejection reserve services (known as contingency raise and contingency lower services respectively in the National Electricity Market) are used to respond to any sudden contingencies, in order to arrest deviations in system frequency. Spinning reserve is used to respond to the loss of a generator, whereas load rejection reserve is used to respond to the loss of a major load (or group of loads).

[15] This requirement is contained with clauses 3.11.8, 3.11.8C and 3.11.9 of the Wholesale Electricity Market Rules.

[16] To date, System Management has not entered into contracts for part-time provision of ancillary services due to the administrative overheads that this would create.

[17] Independent Market Operator Capacity Credit historical information is available at:
http://wa.aemo.com.au/home/electricity/reserve-capacity/assignment-of-capacity-credits

highest priority reform in the Independent Market Operator's 2013-2016 Market Rules Evolution Plan process.[18]

The expansion of competition in ancillary services is discussed in section 3.3.

2.4 Portfolio bidding

In the current Wholesale Electricity Market, all independent power producers are required to offer into the balancing market on a facility basis whereas Synergy offers on a portfolio basis. While Synergy has the option to offer into the balancing and load following markets on a facility basis, it has not exercised this option. The Electricity Market Review understands that this portfolio bidding approach for Synergy is unique amongst liberalised electricity markets in the world.

Portfolio bidding is a historical legacy from the time when Synergy's generation portfolio (at the time held by the fully integrated Western Power Corporation) represented the only power stations in the market, and the dispatch controller was a branch of the same organisation.[19] However, progressive changes to the Wholesale Electricity Market, particularly the development of the balancing market to implement merit order dispatch of generating capacity, have largely obviated the case for portfolio bidding.

The current portfolio bidding approach is incompatible with a security-constrained market design. A security-constrained market clearing engine must forecast when network limits will be reached – requiring knowledge of the quantity of energy that will be injected and withdrawn at each location of the network – in order to determine the least cost dispatch for the market. In contrast, the portfolio offer provided by Synergy is for the sum of energy to be provided from all of its power stations, and does not specify where on the network energy from the Synergy portfolio will be generated. This leaves System Management reliant on its operators' experience and *ad hoc* information from Synergy to decide which Synergy units should be dispatched to ensure compliance with network limits.

Market transparency and equity between market participants are reduced by the portfolio bidding approach, and effective market monitoring is impeded. The Economic Regulation Authority has argued that portfolio bidding may adversely affect the delivery of efficient outcomes for the market.[20] As discussed earlier, the current portfolio approach makes it impossible to discern the boundary between balancing and load following services, which prevents any meaningful assessment of the efficiency of the load following service. In addition, there is an implicit cross-subsidy in portfolio dispatch for Synergy, in that System Management performs functions for Synergy that it does not perform for other generators, yet these functions are funded from market fees that are paid by all generators and retailers.

It is recognised that current market arrangements would make it difficult for Synergy to provide offers on an individual facility basis. This is because Synergy, as the default provider of ancillary services, would not have enough information available at the time of gate closure

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18 Documents available at http://wa.aemo.com.au/home/imo/rules/market-rules-evolution-plan

19 System Management continues to act on behalf of Synergy to make decisions in real time regarding which generation facilities to operate, accounting for advice from Synergy that is provided periodically.

20 Economic Regulation Authority, *Discussion Paper: 2014 Wholesale Electricity Market Report to the Minister for Energy*, November 2014, p.21, available at: http://www.erawa.com.au/cproot/13865/2/2014%20Report%20for%20the%20Minister%20for%20Energy%20(Including%20Appendix%201).PDF

(two hours before the start of the trading interval) to form its offers in a way that ensured efficient dispatch for these services. Synergy has argued that it must continue to offer on a portfolio basis for this reason, under the present arrangements.

Implementation of co-optimised markets for energy and ancillary services would remove this impediment. Synergy would offer its generators into each of these markets separately, and the complex decision about which facilities should be used to provide each service would be made by the market clearing engine just before the start of the dispatch interval, when all the necessary information is available.

The transition to facility bidding for Synergy is described further in section 3.2, while co-optimisation is discussed in section 3.3.

2.5 Gate closure

'Gate closure' means the deadline for changes to submissions into an energy or ancillary service market. Gate closure for the balancing market currently occurs two hours before the start of the trading interval for all non-Synergy generators. Synergy has an earlier gate closure (between 4 and 9.5 hours ahead of the trading interval) and restricted submission timing to address market power concerns.[21]

The current gate closure arrangements can result in efficiency losses. Generators are unable to adapt to changes to forecasts and system conditions following gate closure, which may result in conservative bidding behaviour and inefficient market outcomes. The current gate closure can also impose delays on a return to operation following plant maintenance, meaning that cheaper energy may not be able to be accessed during this lag period. In addition, the earlier gate closure for Synergy provides unequal opportunities for market participants to respond to changing market conditions (including Synergy's offer prices).

Market participants voted shortening of the gate closure as the third highest priority reform in the Independent Market Operator's 2013-2016 Market Rules Evolution Plan.

Shortening of the gate closure arrangements is discussed in sections 3.4 and 5.8.3.

2.6 Short Term Energy Market (STEM)

The STEM is a day-ahead market operated by Australian Energy Market Operator, in which market participants can buy and sell energy for the following trading day[22] to adjust their net bilateral positions. Market participants must offer all of their available generation capacity into the STEM or pay refunds on their reserve capacity payments.

Since the introduction of the balancing market the link between the STEM and physical dispatch has been broken, with the balancing market used for gross dispatch. During targeted stakeholder consultation, several market participants have questioned whether the STEM continues to serve a useful purpose in its current form. There is however, widespread agreement that some form of forward market would still provide benefits through

[21] Gate closure for the load following market occurs earlier and applies to six-hour blocks rather than individual trading intervals.

[22] A trading day is defined in the Wholesale Electricity Market Rules as the 24-hour period from 8:00 am until the following 8:00 am (Western Standard Time).

transparency of forward price signals, promoting liquidity and mitigating market power concerns.

The potential reform of the STEM is considered in section 3.7.

2.7 Summary

Reforms to the energy and ancillary service operations and processes in the Wholesale Electricity Market could address many of the deficiencies described in this chapter. These reforms, discussed in subsequent chapters, have the potential to remove inefficiencies that increase costs to consumers, as well as improving transparency and competition.

3. The core reforms

Chapter 2 highlighted that changes to the energy and ancillary service markets in the South West Interconnected System are necessary and could address material inefficiencies in the current market design.

This chapter explains and justifies three essential, core aspects of the reforms to the energy and ancillary markets, being:

- a security-constrained market design;
- facility bidding for all market participants; and
- co-optimisation of energy and ancillary services.

It also describes three important reforms that are simple to implement at the same time and are expected to deliver efficiency improvements (later gate closure, shorter dispatch cycle and ex-ante pricing) and details the Electricity Market Review's considerations in respect of the STEM.

Benefits associated with each of the reforms are described qualitatively, with quantitative assessment provided where analysis is practicable. However, the limited transparency of some aspects of the current energy and ancillary service arrangements prevents quantitative assessment of several of the proposed reforms.

3.1 Security-constrained market design

Section 2.1 explained that the adoption of a security-constrained market design will be essential to maintain power system security for the South West Interconnected System under a constrained network access model, with the current unconstrained market design becoming unworkable as network congestion increases in the future. It explained that a security-constrained market design will also improve market efficiency by aligning energy market operations with the physical realities of the network.

The vast majority of electricity markets employ security-constrained market designs, including the National Electricity Market. The Wholesale Electricity Market and the Alberta market in Canada appear to be the only exceptions.[23]

In security-constrained markets, dispatch is based solely on security-constrained economic principles and takes the realities of network constraints into account, so that the resulting dispatch instructions are economically efficient, physically achievable and do not threaten system security. Information regarding expected network congestion is transparent to market participants in advance of dispatch, dramatically improving the reliability of pre-dispatch forecasts and allowing generators to account for this information when forming their offers.

[23] Independent Market Operator, *IMO Submission to Electricity Market Review Discussion Paper*, September 2014, p52, available at: http://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/Independent-Market-Operator.pdf.

The market and dispatch systems currently used in the South West Interconnected System are unable to support security-constrained economic dispatch and could not feasibly be modified to do so. A security-constrained market must use a sophisticated market clearing engine that integrates generation, demand and network data ahead of, and in, real time to determine the least cost dispatch for each dispatch interval. In order to align with the adoption of the national framework for network regulation, a new market clearing engine must be operational by 1 July 2018.

Adoption of a security-constrained market design is expected to deliver the following benefits:

- transparent determination of the least-cost dispatch outcome for the market, accounting for generation offers and network conditions,
- improved short-term efficiency through better quality dispatch forecasts, allowing market participants to compete with greater confidence;
- improved long-term efficiency through publication of information that shows the economic costs of constraints and the locations where new capacity or network investment will deliver greatest value to consumers;
- greater automation in the calculation of network constraints, which improves network efficiency by allowing constraints to be set less conservatively without compromising system reliability; and
- greater automation in the dispatch process, so that system security can be managed efficiently as the level of constraints increases.

3.2 Facility bidding

A transition to facility bidding for Synergy is essential as the current portfolio bidding approach that it uses is incompatible with a security-constrained market design, as explained in section 2.4. Facility bidding is required to enable the least cost resolution of network constraints and the least cost dispatch of generation in the market.

As part of reform implementation, it is anticipated that discussions will take place between the Australian Energy Market Operator and Synergy (and potentially other generators) to establish whether there is a reasonable case for any co-located generating units to be aggregated for the purposes of bidding and dispatch. This would be consistent with National Electricity Market arrangements, which allow such aggregation under specific circumstances as described in section 5.2.2 of this position paper.

It is expected that there will be incremental up-front capital and operating costs for Synergy to transition to facility bidding. In particular, with Synergy's portfolio exceeding 30 facilities, it is likely that an enhanced trading system and expanded trading team will be required to implement and operate a facility bidding regime. This would be consistent with the experience and business-as-usual operating practices of large National Electricity Market vertically integrated generators, such as AGL and Origin Energy.[24]

[24] Recognising that the formation of offer prices and quantities for the Synergy portfolio necessitates similar facility-based information as would be required for facility bidding.

Facility bidding would provide Synergy with greater control and flexibility to optimise the operation of its power stations. As System Management currently largely controls Synergy's portfolio in real time, the current scope for Synergy to optimise real time operations is constrained.

It is anticipated that any net additional costs for Synergy will be outweighed by wider efficiency benefits that can be achieved through adoption of the core reforms described in this chapter.

Previous consideration of this topic outside of the Electricity Market Review process has highlighted concerns that the transition to facility bidding for Synergy may increase the costs of managing network congestion and ancillary services for consumers, on the basis that some of these services are provided within the portfolio, but not paid for by the market. Facility bidding would be expected to increase the transparency of ancillary service costs and remove cross-subsidies in the short to medium-term, with longer-term benefits to accrue from increasing scope for competition in the provision of these ancillary services, as is discussed in the next section.

It has also been highlighted previously that Synergy would need to develop capability (systems and personnel) to manage the dispatch of its generation portfolio. However, currently the costs of dispatching the Synergy portfolio are incurred by System Management and funded by the market, constituting an unnecessary cross-subsidy that would be removed by the proposed changes.

3.3 Co-optimisation of energy and ancillary service markets

It is common practice in competitive electricity markets to co-optimise energy with frequency control ancillary services – spinning reserve, load rejection reserve and load following. In this context, co-optimisation refers to the process of determining the overall least-cost dispatch outcome for both energy and ancillary services. This process may involve complex trade-offs, particularly as the ability for a generator to provide ancillary services will be influenced by its current production level.

Co-optimisation simplifies and de-risks the bidding process for market participants, allowing generators to offer simultaneously into energy and multiple ancillary service markets while being commercially indifferent as to which services they are dispatched to provide.

Given the size of Synergy's generation portfolio and its dominance in the provision of ancillary services, the co-optimisation of energy and ancillary services is essential for facility bidding by Synergy to be operable and efficient, as explained in section 2.4. This means that co-optimisation is essential to support the implementation of a security-constrained market design.

Co-optimisation would also be expected to deliver substantial efficiency benefits, including:

- reducing the current risk premium in load following prices;
- promoting greater competition in the provision of ancillary services;
- enabling a later (and coincident) gate closure for energy and ancillary service markets (the benefits of which are described in the next section); and

- enabling productive efficiency gains to be realised, to the extent that co-optimised dispatch outcomes result in a lower total cost than the current approach.

Quantitative analysis of the likely benefits that could be realised in the South West Interconnected System from co-optimisation is not possible as the manner in which the Synergy portfolio is currently dispatched makes it impossible to discern which of its facilities are providing ancillary services. Further, it appears that estimates derived from the experience of other electricity markets may be unrepresentative as co-optimisation has rarely been implemented in isolation.[25]

The market systems that perform the co-optimisation process assume the use of competitive markets for frequency control ancillary services. These ancillary services are particularly conducive to short-term competitive procurement as the quantity required for each service can vary throughout the day, and the ability of a facility to provide each service may also vary dependent on its current level of production.

As was explained in section 2.3, there are likely to be economic benefits in expanding competition in ancillary services and market participants have expressed interest in greater competition for these services. Competition would increase the transparency of ancillary service costs, remove cross-subsidies in the short to medium term, and likely place downward pressure on these costs over time.

The costs of load following increased after the commencement of the competitive load following market arrangements in 2012.[26] However, it is anticipated that the reforms proposed in this position paper would promote increased competition in this market by reducing risks, lowering the barriers to participation and placing downward pressure on the load following requirement.

It is also likely that markets for spinning reserve and load rejection reserve would be more competitive than the load following market has been to date. The South West Interconnected System already has three suppliers of spinning reserve and several other participants have expressed interest in providing this service during targeted consultation (and have the capacity to do so). To date, the administered price for load rejection reserve has been zero[27], meaning that there has been no driver for System Management to seek other providers, but numerous participants would also be expected to be able to provide this service. The establishment of competitive markets and pragmatic technical qualification standards are expected to enable competition from additional generators and a few large customers. It is expected that there is a cost incurred in providing the load rejection reserve service, so the establishment of competitive markets would be expected to reduce cross-subsidies and place downward pressure on this cost.

The market clearing engines described in section 3.1 include the capability to operate competitive, co-optimised ancillary service markets. Consequently, the implementation of

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[25] For example, the implementation of co-optimisation in the National Electricity Market coincided with a relaxing of the frequency operating standards.

[26] Economic Regulation Authority, *2014 Wholesale Electricity Market Report to the Minister for Energy*, February 2015, p.24.

[27] Economic Regulation Authority, Determination of the Ancillary Service Cost_LR Parameter, March 2013, p.4, available at: https://www.erawa.com.au/cproot/11212/2/20130318%20-%20Determination%20of%20the%20Ancillary%20Service%20Cost_LR%20Parameter.pdf

co-optimisation is not expected to require additional costs beyond what is already required to implement security-constrained dispatch.

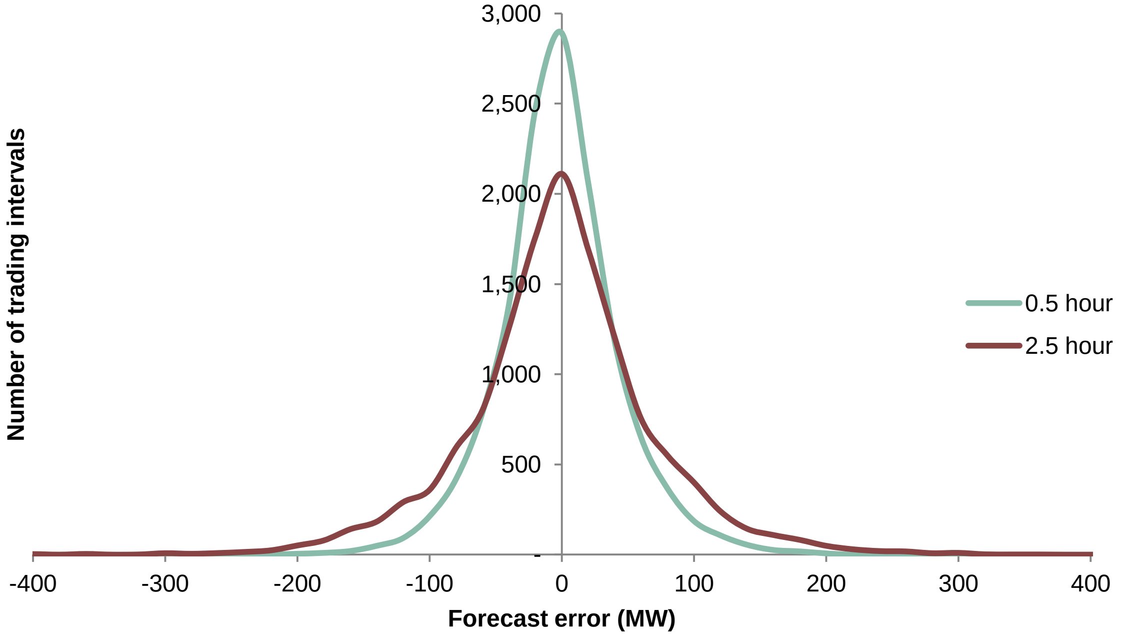
3.4 Later gate closure

Later gate closure, while not considered essential as per the reforms described in sections 3.1 to 3.3, has the potential to deliver considerable efficiency benefits and lower costs for consumers.

The efficiency of markets is maximised when decision-making is informed by the most accurate and timely information that can be made widely available. In the context of electricity markets, later gate closure allows market participants to make decisions closer to real time with the benefit of more accurate forecasts (including forecasts of electricity demand and wind) and up-to-date knowledge of network conditions and the status of generation facilities (including outages).

Analysis of demand forecasts developed by System Management demonstrates the material improvement in accuracy as the trading interval nears. Figure 3.1 shows the error distributions for forecasts produced 2.5 hours and 0.5 hours ahead of the start of the trading interval for the period from January to September 2015. The 95 per cent confidence interval[28] is reduced from 128 MW for the 2.5-hour-ahead forecasts to 78 MW for the 0.5-hour-ahead, an improvement of about 50 MW.

Figure 3.1: Forecasting accuracy improvement due to later gate closure, January to September 2015



Source: Oakley Greenwood/The Lantau Group analysis of data from the Australian Energy Market Operator

[28] Determined as 1.96 times the standard deviation.

This increase in forecast accuracy would be expected to lead to improved decision-making by market participants and the system manager. It would reduce risks for generators, with the potential to reduce any risk premium within offer prices and increase market participation.[29]

Later gate closure can also facilitate faster return of generators from outage. The gate closure period imposes a lag period between the time when a generator updates its offers at the completion of maintenance (to reflect the change in its availability) and the time when it may commence operation. This can reduce competition and increase costs to consumers where the generator returning to service has lower operating costs than the marginal price and it is prevented from displacing more expensive generation for a period of time.

To quantify the benefit of earlier return from outage, specific outages were identified for lower-cost non-Synergy generators in which the generator appears to have been unable to dispatch for the current two-hour gate closure period.[30] The costs to the plant owner (predominantly a transfer from other generators) and the system (excluding net value transfers) were then calculated by adding the unavailable plant back into the merit order and recalculating the balancing price. This exercise assumed that gate closure was shortened to occur 30 minutes prior to the start of the trading interval, so the indicative benefit may increase if gate closure is shortened further. The results are presented in Table 3.1.

Table 3.1: Value of earlier return from forced outage (July 2014 to June 2015)

Facility	Number of forced outages selected	Missed revenue for owner	Extra system cost
Alinta Pinjarra Unit 1	2	$10,498	$14,175
Alinta Pinjarra Unit 2	1	$73	$0
Bluewaters Unit 1	3	$24,690	$19,511
Bluewaters Unit 2	14	$147,189	$264,098
Total	20	$182,899	$297,784

Source: Oakley Greenwood/The Lantau Group analysis of data from the Australian Energy Market Operator

These results are indicative only as it is not possible to assess whether market participants would have made different decisions (for example, changes to their offers) with a shorter gate closure. However, the present value effect of similar avoidable costs per year would be in the order of $3 million, based on a discount rate of eight per cent over 20 years.[31]

29 For example, improved certainty of forecasts enables a generator to more reliably predict when, and for how long, it may be able to generate. This helps it to more reliably identify opportunities to operate profitably while at the same time lowering the energy price.

30 Market data from July 2014 to June 2015 was used for this analysis.

31 Given that the systems required to deliver shorter gate closure are essential for other reasons, the benefits are available for as long as the market exists, having no defined timeframe.

Various options exist for gate closure timing, particularly with the greater degree of dispatch automation that will be available due to the implementation of a new market clearing engine for the South West Interconnected System. It is proposed that gate closure for the Wholesale Electricity Market be shortened to no earlier than 30 minutes before the start of the trading interval. Given that energy and ancillary services are to be co-optimised, a common gate closure would apply to the energy and ancillary service markets. Section 5.8.3 includes a more detailed discussion of the gate closure options.

Given that Synergy will be required to transition to facility bidding, it is also proposed that gate closure is harmonised for all market participants.[32]

3.5 Shorter dispatch cycle

Similarly to later gate closure, shortening of the dispatch cycle (that is increasing the frequency with which dispatch instructions are given to generators) becomes feasible with the greater degree of automation provided by a new market clearing engine. A shorter dispatch cycle has the potential to deliver substantial efficiency benefits and lower costs for consumers.

A five-minute dispatch cycle is common practice in electricity markets, in contrast to the 30-minute dispatch cycle currently used in the Wholesale Electricity Market.[33]

If dispatch instructions are issued more frequently, the ability of the energy market to match supply to fluctuating demand is improved, shifting the boundary between the balancing and load following services.

In the balancing market, generators are dispatched to targets at the end of the dispatch interval based on forecasts available at the time. A shorter dispatch cycle reduces the forecast horizon and would be expected to yield improvements in forecast accuracy, all other factors aside. This reduces the reliance on load following to compensate for forecasting error.

To estimate the benefit associated with forecast improvement, one-minute generation data[34] was used to produce a forecast of the total requirement for dispatch of scheduled generators in the next dispatch interval.[35] Dispatch cycles of five minutes, 10 minutes and 30 minutes were modelled. The forecast dispatch requirements were then compared to actual generation data to estimate the forecasting error for each dispatch cycle.

[32] This is consistent with the current Wholesale Electricity Market Rules, whereby Synergy would have the same gate closure and offer submission timings as private sector generators for any Stand Alone Facilities that are removed from the Balancing Portfolio.

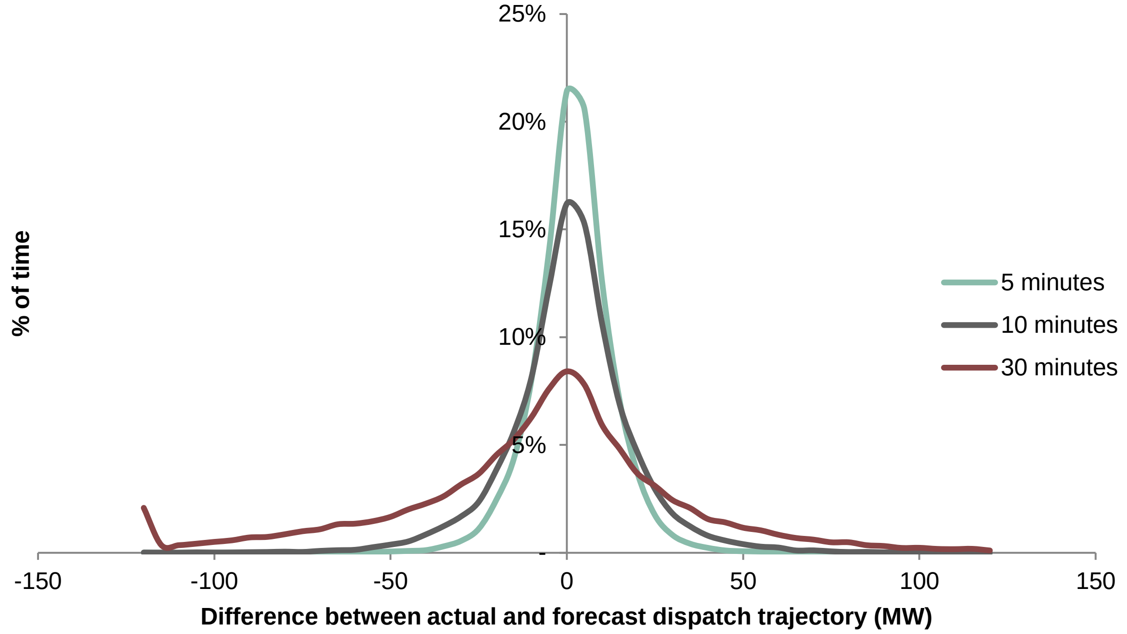
[33] Under some circumstances, System Management issues interim instructions to generators that take effect 10 minutes and 20 minutes after the start of the trading interval. However, all dispatch instructions target the end of the relevant trading interval.

[34] Data from October 2014 was used.

[35] Various forecasting approaches were tested, with the reported savings being from the most conservative forecasting approach.

Figure 3.2 shows the results of this analysis, demonstrating the considerable improvement in forecasting accuracy that can be achieved through shortening of the dispatch cycle. All other factors aside, a reduction in dispatch interval from 30 minutes to five minutes has the potential to reduce the total forecasting error by as much as 50 per cent. Given that forecasting error is estimated to drive more than half of the load following requirement at present[36], even a conservative 30 per cent reduction in forecasting error could reduce the total load following requirement by around 15 per cent.

Figure 3.2: Forecasting accuracy improvement due to shorter dispatch interval, October 2014



Source: Oakley Greenwood/The Lantau Group analysis of data from the Australian Energy Market Operator

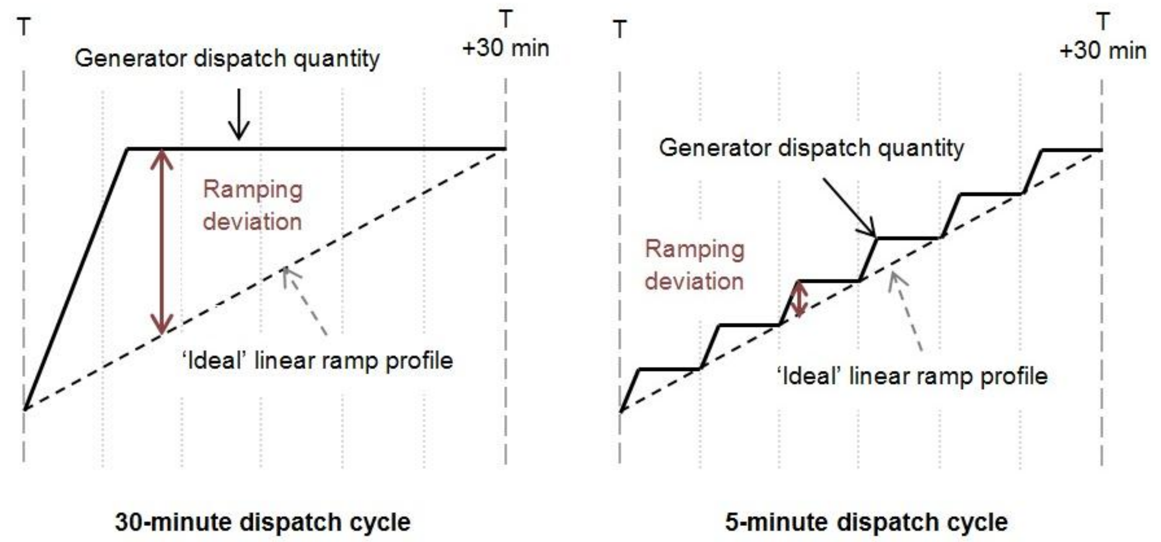
A shorter dispatch cycle would also dramatically lessen the requirement for load following to balance the fast ramping of generators, which in many cases exceeds the rate that is necessary for balancing supply and demand and sees a generator reach its dispatch target well before the end of the interval.

To assess this benefit, actual generator dispatch instructions (based on maximum ramp rates), were used to calculate minute-by-minute generator dispatch quantities for non-Synergy generators.[37] These were then compared to generator dispatch quantities that would result from linear ramping to the end of interval target to calculate the deviation due solely to this ramping effect. To simulate a five-minute dispatch cycle, the actual dispatch instructions were then disaggregated to five-minute targets and minute-by-minute generator dispatch quantities were recalculated, with the corresponding deviation from linear ramping also calculated. These approaches are shown schematically in Figure 3.3.

[36] Analysis performed jointly by the Independent Market Operator and System Management considered the relative contributions of different drivers of the load following requirement. This analysis was presented to the Market Advisory Committee in December 2014 and is available at http://wa.aemo.com.au/docs/default-source/Governance/Market-Advisory-Committee/4-lfas-update-for-december-2014-mac-v2-kr.pdf?sfvrsn=0. LFAS source 1 (System Load) and source 2 (Non-Scheduled Generation forecast) are both attributed to forecasting error.

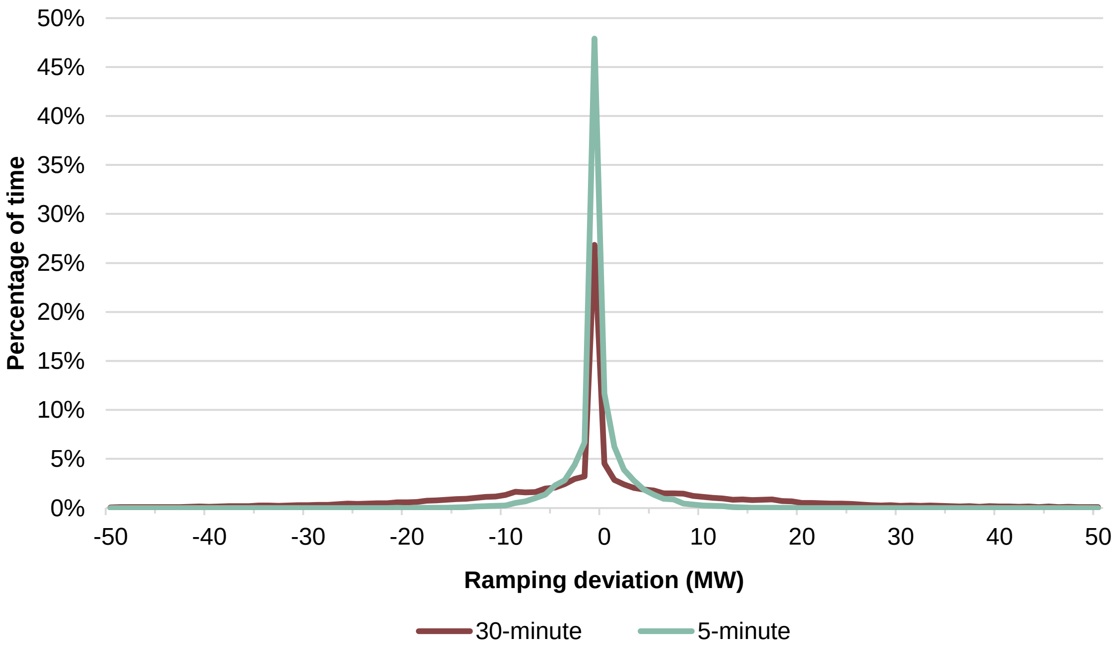
[37] It is not possible to conduct this analysis in respect of Synergy's generators as they are not issued dispatch instructions in the same manner as non-Synergy generators.

Figure 3.3: Schematic representation of dispatch cycle and ramping deviations



The results of the analysis are shown in Figure 3.4. Excluding other factors, a reduction in dispatch interval from 30 minutes to five minutes would reduce ramping deviations by more than 80 per cent. Ramping deviation is estimated to drive about one-quarter of the load following requirement, suggesting that five-minute dispatch cycle could reduce the total load following requirement by 20 per cent.

Figure 3.4: Ramping deviation improvement due to shorter dispatch cycle



Source: Australian Energy Market Operator

It is not possible to precisely translate the estimated reductions in the load following requirement to estimates of financial benefits as the manner in which the Synergy portfolio is dispatched makes it impossible to measure the quantity of load following capacity being used. While the total cost of the load following market was $45 million for the 12-month period ending on 31 March 2015[38], it is possible that some load following is provided by the Synergy portfolio but not paid for by the market.

It is also acknowledged that the analysis presented in this section is limited to one-minute data resolution.

However, using the annual load following cost of $45 million as a guide, it can be conservatively estimated that the proportional reductions in the load following requirement described in this section would result in cost reductions exceeding $10 million per year. With a discount rate of eight per cent over 20 years, this amounts to a benefit exceeding $100 million in present value terms.

For these reasons, and to align with common practice in electricity markets, the Electricity Market Review proposes a five-minute dispatch cycle for the Wholesale Electricity Market. This change would complement the other proposed reforms in this paper.

3.6 Ex-ante pricing

Prices are currently determined ex-post in the Wholesale Electricity Market, a minimum of two days after the relevant trading interval. In contrast, the majority of liberalised electricity markets determine prices on an ex-ante basis.

The decision between ex-ante and ex-post pricing represents a trade-off between greater certainty (ex-ante) and greater accuracy (ex-post). During targeted consultation market participants expressed a preference to transition to ex-ante price determination.

Improved price certainty directly influences the confidence with which generators can make commercial and operational decisions. A shift to ex-ante price determination would also remove the need for constraint payments to provide make-whole payments to generators where ex-post prices are different from what was forecast at the time of dispatch. While it is not practicable to quantify these benefits, they are expected to outweigh the benefits from the marginal improvements in accuracy delivered by ex-post pricing.

Consequently, the Electricity Market Review proposes a shift to ex-ante price determination.

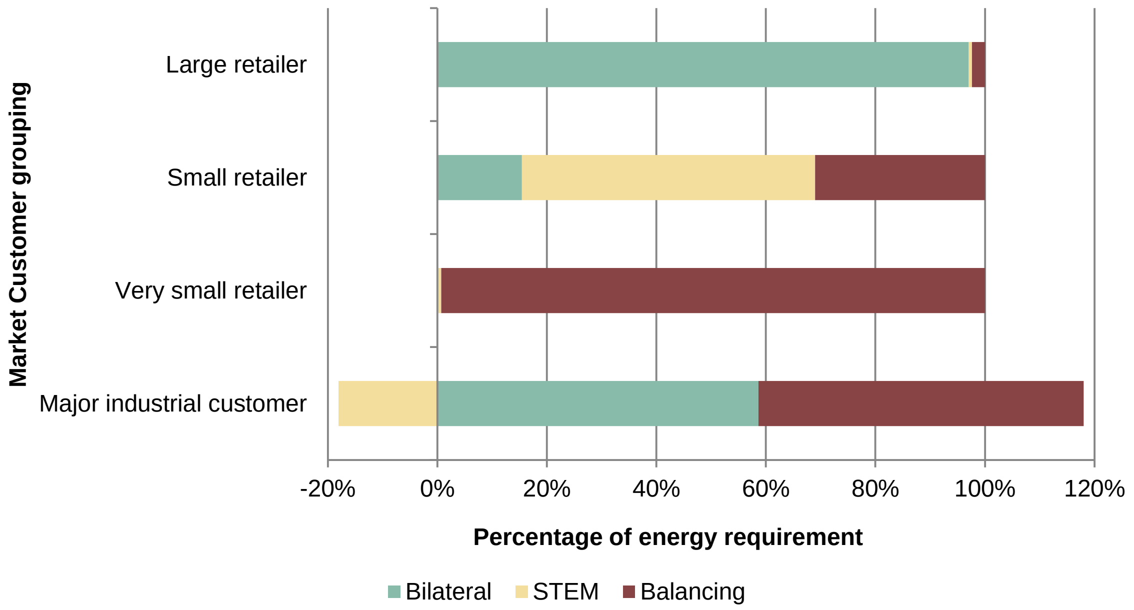
3.7 Short Term Energy Market (STEM)

As discussed in section 2.6, market participants generally agree that a forward market provides benefits through transparency of forward price signals, promoting liquidity and mitigating market power concerns.

[38] Western Power (System Management), Ancillary Services Report 2015, 12 August 2015, available at http://wa.aemo.com.au/home/electricity/market-information/system-management-reports.

While STEM trades represent only a small share of total energy consumption within the South West Interconnected System, smaller retailers appear to rely heavily on the STEM as a source of wholesale electricity supply and as a risk management tool, as demonstrated by Figure 3.5 below. This figure indicates that smaller retailers, with market shares between 0.1 per cent and three per cent, are purchasing more than half of their energy requirement through the STEM. In contrast, large retailers purchase the vast majority of their energy requirements bilaterally (which, in the case of a gen-tailer, may include self-supply), very small retailers are predominantly purchasing energy in the balancing market and major industrial customers are using a combination of bilateral and balancing purchases.

Figure 3.5: Wholesale energy purchasing method, July 2015



Source: Australian Energy Market Operator

(1) Retailer groupings have been determined from share of energy purchased. Large retailers are all retailers with a market share of at least three per cent, small retailers have a market share of between three per cent and 0.1 per cent and very small retailers have a market share of less than 0.1 per cent.
(2) The negative STEM quantity for Major industrial customers reflects that these customers were, in aggregate, purchasing energy through bilateral contracts, on-selling some of that energy in the STEM and then were net purchasers of energy in the balancing market.

While the STEM does not provide long forward price signals (being a day-ahead market), it makes energy available at reasonable prices and with relatively low transaction costs[39], and incorporates market power mitigation measures (including mandatory offering of spare certified capacity) that alleviate concerns about the competitiveness of the market structure in the South West Interconnected System. The Electricity Market Review has not found an alternative forward market design that appears able to provide all these features under the current market structure.

Consequently, the Electricity Market Review considers that there is insufficient case for changing the STEM at this time, provided that the cost to retain the STEM is not excessive.

[39] For smaller retailers, the transaction costs for trading in the STEM would be considerably lower than for bilateral contracting.

In the longer term, as the market structure becomes more competitive, the Electricity Market Review envisages various forward markets could develop according to the needs of market participants. Such markets could develop outside of the formal Wholesale Electricity Market, potentially operated by the Australian Stock Exchange (as occurs for the National Electricity Market), and could support longer term (for example, weekly or monthly) trades. These markets could supersede the STEM, providing an opportunity to abolish it.

The likely future abolition of the STEM weakens the case for substantive modification to the STEM in the short term. However, section 5.7 proposes changes to processes associated with the STEM, such as the abolition of Resource Plans and changes to process timings.

3.8 Summary

Section 2.1 outlined that a security-constrained market design will be essential to maintain power system security under a constrained network access model, with the current unconstrained market design becoming unworkable as network congestion increases in the future. This chapter explained that the adoption of a security-constrained market design will require the implementation of a sophisticated market clearing engine, to replace the current market and dispatch systems that lack the required capabilities.

This chapter has also explained that facility bidding for Synergy and co-optimisation of energy and ancillary service markets (including the establishment of new competitive markets for spinning reserve and load rejection reserve) are essential reforms that result from the adoption of a security-constrained market design and the requisite market clearing engine.

Request for comment – submissions providing feedback on the essential reforms – the implementation of a security-constrained market design, facility bidding for Synergy and co-optimisation of competitive energy and ancillary service markets – are encouraged.

This chapter also proposes later gate closure, a five-minute dispatch cycle and ex-ante price determination.

Request for comment – the Electricity Market Review proposes later gate closure for the energy and ancillary service markets, five-minute dispatch cycle and ex-ante price determination.

Submissions providing feedback on these proposed reforms, including alternative options, are encouraged.

Finally, this chapter proposes retention of the STEM, while acknowledging that it could become redundant in the future if and when forward markets develop outside of the Wholesale Electricity Market, at which time the STEM could be abolished.

Request for comment – submissions providing feedback on the proposed retention of the STEM are encouraged.

The core reforms described in this chapter are expected to ensure efficient, least-cost dispatch of generation. Dispatch outcomes would be more transparent and predictable for all stakeholders, improving market confidence and assisting assessment and reviews of market performance. The reform package would be expected to reduce risk for market participants and drive efficiency benefits expected to exceed $100 million in present value terms.

4. The case for alignment with the National Electricity Market

The transfer of market and system operation functions to the Australian Energy Market Operator was announced by the Minister for Energy on 30 September 2015.[40] While Western Australia will not be adopting the National Electricity Rules for the operation of the Wholesale Electricity Market, the transfer of certain functions to the Australian Energy Market Operator creates opportunities for synergies that could reduce administration costs. This includes opportunities for leveraging the Australian Energy Market Operator's technology and National Electricity Market operations and processes where these meet the needs and characteristics of the South West Interconnected System.

The majority of the reforms discussed in Chapter 3 would strongly align the major energy and ancillary service design features of the Wholesale Electricity Market with the National Electricity Market operations and processes. Some differences will remain, such as differences in price caps and outage scheduling, but these are not expected to require major differences in the market and dispatch systems from those used in the National Electricity Market.

Given this likelihood, the Australian Energy Market Operator has offered to use its National Electricity Market Dispatch Engine (NEMDE) system as the market clearing engine for the Wholesale Electricity Market. The alternative to NEMDE would be for a commercially available market clearing engine to be purchased and configured for the Wholesale Electricity Market.

This chapter compares the market clearing engine options and assesses their relative merits for the Wholesale Electricity Market. This requires consideration of the nature of locational dispatch and locational pricing.

4.1 Comparison of market clearing engine options

NEMDE has been designed and developed by the Australian Energy Market Operator, specifically for the National Electricity Market.

NEMDE is capable of satisfying the core reforms described in sections 3.1 to 3.6 of this position paper.[41] NEMDE performs security-constrained co-optimised dispatch of energy and ancillary markets. It performs dispatch every five minutes and operates with no formal gate closure, in that rebidding is only limited by the time required by NEMDE to calculate dispatch schedules.[42] Prices are determined ex-ante.

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[40] Hon Dr Mike Nahan MLA, Minister for Energy, Media Statement, 30 September 2015. https://www.mediastatements.wa.gov.au/Pages/Barnett/2015/09/Electricity-reform-gains-momentum.aspx,

[41] It is expected that the STEM would be operated via a system external to the market clearing engine.

[42] In effect, this results in a gate closure about a minute prior to the start of the dispatch interval.

The use of NEMDE as the market clearing engine for the Wholesale Electricity Market would allow the Australian Energy Market Operator to maximise its re-use of existing systems and processes, reducing implementation, administration and ongoing operational costs. Re-use also reduces the risk of unknown factors that could potentially delay the implementation and threaten other proposed Electricity Market Review reforms. The system is familiar not only to the Australian Energy Market Operator but also to potential market entrants who are already active in the National Electricity Market.

Contemporary, off-the-shelf market clearing engines, of which several are available, also have the capability to satisfy the core reforms in sections 3.1 to 3.6. Such a system would need to be purchased, installed, configured and tested, and Australian Energy Market Operator staff would require training in its operation.

The National Electricity Market differs in design from many other liberalised electricity markets in:

- the way in which the network is represented in the market clearing engine and network losses are modelled; and
- the extent and nature of locational pricing.

These design decisions influence the choice of market clearing engine and so are considered in the following sections.

4.2 Network representation in market clearing engine

Two main options exist for the method of network representation in the market clearing engine. Both methods are capable of delivering secure system operation.

- A full nodal network model is a topological representation of the network that directly represents the capabilities of all network elements in the model, and dynamically forecasts flows and energy losses for each network element. This approach is more common in liberalised electricity markets.
- A regional 'hub-and-spoke' model is a simplified, notional representation of the network as a series of radial lines (spokes) emanating from one or more reference nodes (hubs). In this approach, network limitations are represented through a set of constraint equations[43], and while the inter-regional line losses are modelled dynamically, intra-regional transmission line losses are modelled using static average marginal loss factors. This approach is used in the National Electricity Market and is more similar to the current Wholesale Electricity Market design (particularly in the representation of network losses).

[43] Constraint equations may represent thermal line limits, network stability limits or contingency scenarios. The National Electricity Market has more than 10,000 constraint equations. Only a small proportion (in the order of 10 per cent) may be used at a time, as a single network limit may need to be represented in multiple equations that reflect different network conditions.

By directly representing the capabilities of network elements, the full network model is, in principle, more transparent and can evolve more easily with changes in network configuration and ratings. It could readily determine locational prices at more locations if it was desired to provide stronger locational price signals to market participants. Being the more common approach, a full network model could be implemented using an off-the-shelf system from a reputable technology provider.

In practice, the Australian Energy Market Operator has extensive experience with the simplified hub-and-spoke model as used in the National Electricity Market and implemented in NEMDE. A hub-and-spoke model can evolve to reflect changes to the network configuration, although this process is relatively more cumbersome than for a full network model as it may require large numbers of constraint equations to be rewritten.[44]

However, while it is possible to increase the number of separate locational prices in a hub-and-spoke model, this requires the addition of new hubs to the model and substantive work in rewriting network constraint equations. There is also likely to be a practical limit to how far the multi-regional basis of NEMDE can be extended, which may limit the extent to which locational price differentiation could be achieved (if it was deemed desirable or necessary).

Given these circumstances and the identified benefits of a NEMDE-based solution, the choice of market clearing engine then rests predominantly on whether there is perceived to be benefit in determining multiple locational prices for energy and ancillary services across the South West Interconnected System. As discussed in the following section, the Electricity Market Review is unable to demonstrate sufficient benefit in locational differentiation of energy and ancillary service prices to justify the associated costs and risks at this time.

Consequently, the use of a hub-and-spoke model for the Wholesale Electricity Market is proposed, similar to the model used in the National Electricity Market.

4.3 Locational pricing

The extent to which locational price signals are communicated to market participants can vary between two extremes.

- Full locational marginal pricing (or nodal pricing) involves the determination of distinct prices for each (large) injection or withdrawal point on the transmission network. Each locational price incorporates the costs of network losses and network congestion.
- At the other end of the spectrum, a single reference node price can be determined, with average marginal loss factors used to account for network losses in both dispatch and settlement. The cost of network congestion away from the reference node is not reflected in the market price for each trading interval, but may be reflected in overlaying mechanisms such as constrained-on compensation payments.[45]

[44] The Australian Energy Market Operator has in recent years been increasing automation in the creation, updating and invocation of constraint equations. Further information is available at http://www.aemo.com.au/Electricity/Market-Operations/Congestion-Information-Resource/Constraint-Automation-Closing-the-Loop-Discussion-Paper.

[45] Constrained-on compensation (as used in the current Wholesale Electricity Market design) and direction compensation (as used in the National Electricity Market) are described in section 5.9.4.

The regional design of the National Electricity Market lies between these two extremes. The National Electricity Market operates with five regions, each with its own reference node.[46]

During targeted stakeholder consultation to assist the development of this position paper, market participants generally opposed the increased complexity that locational pricing would entail. With locational pricing, the prices for two locations can diverge when network congestion occurs, causing basis risk[47] for parties that trade between these locations. This basis risk requires the development of risk management mechanisms (such as financial transmission rights) in order to support such trading, which has proven challenging in other electricity markets. In the absence of such risk management mechanisms, parties may be unwilling to trade across congested parts of the network, reducing competition.

The introduction of locational pricing in the Wholesale Electricity Market would require sizeable changes to the STEM, which is designed around a single reference node price. Such re-design could be costly and would be contrary to the long-term direction for the STEM that is described in section 3.7 of this position paper.

Further, analysis of the benefit of locational price signals would require highly speculative assumptions regarding how market participants will respond to these signals, compared to how they will respond to a market design with a single reference node. It is clear that energy prices are only one of many factors that will influence locational decisions of investors, which for a power station will also include the availability and cost of land, fuel (which may include the suitability of renewable resources) and access to the transmission network.

The Electricity Market Review proposes that the Wholesale Electricity Market continue to operate with a single reference node price on the grounds that this avoids creating basis risk and the need for risk management mechanisms, allows the retention of STEM and is consistent with market participant views. This would closely align the Wholesale Electricity Market with the individual regions of the National Electricity Market and could be readily implemented using NEMDE.

However, the Electricity Market Review proposes that a constrained-on compensation mechanism should continue to operate in the Wholesale Electricity Market. Constrained-on compensation is explained further in section 5.9.4. This represents a divergence from the National Electricity Market design but would reflect the principle that a generator that is required to operate should be compensated for its operating costs.

4.4 Summary

This chapter proposes the following in respect of locational dispatch and pricing for the Wholesale Electricity Market:

- the use of a hub-and-spoke model for representation of the network; and
- the use of a single reference node price.

[46] The region boundaries in the National Electricity Market are closely aligned with state boundaries.

[47] In electricity markets, basis risk is the risk that a participant is required to settle a bilateral contract using a price that is different to the price it receives from the market. For example, if a generator contracts with a retailer on the basis of the energy price at the retailer's location, then the generator may be exposed to basis risk. The greater the difference between the two prices the greater the basis risk.

The Electricity Market Review further proposes the use of NEMDE as the market clearing engine for the Wholesale Electricity Market. The Electricity Market Review considers that the potential benefits of a more sophisticated, off-the-shelf system are unlikely to outweigh the material benefits of a NEMDE-based implementation in terms of simplicity, familiarity, cost, risk and speed of implementation.

Request for comment – submissions providing feedback on the proposal to implement market reforms using NEMDE, a hub-and-spoke network model and single reference node pricing are encouraged.

5. Features of the proposed design

5.1 Overview

The principal features of the proposed design for the Wholesale Electricity Market's energy market operations and processes are:

- implementation of real-time energy and frequency control ancillary service markets, based on the National Electricity Market's spot market design and utilising the Australian Energy Market Operator's systems and processes as far as practicable; and
- retention of the STEM.

It is also proposed to amend several other aspects of the Wholesale Electricity Market design to more closely align with the National Electricity Market. Some of these changes are essential to support other Electricity Market Review reforms, including adoption of the national framework for network regulation and the proposed introduction of full retail contestability. The proposed changes are also expected to:

- reduce implementation and ongoing operational costs by maximising the Australian Energy Market Operator's ability to leverage its systems and processes in the Wholesale Electricity Market;
- implement some of the more sophisticated features of the National Electricity Market that would become available at little additional cost with the adoption of the Australian Energy Market Operator's market systems;
- support the entry of new competitors who are already active in the National Electricity Market and are familiar with its operation; and
- correct several existing anomalies in the Wholesale Electricity Market Rules.

It is expected that variations from the National Electricity Market design will be required to reflect factors specific to the Wholesale Electricity Market, such as:

- differences in the physical characteristics of the South West Interconnected System compared with the national grid;
- differences in market structure compared with the National Electricity Market;
- the operation of the Reserve Capacity Mechanism;
- the regulatory framework and governance arrangements for the South West Interconnected System; and
- circumstances where the current Wholesale Electricity Market provisions are more flexible or sophisticated than their National Electricity Market equivalents.

It is not proposed to adopt National Electricity Market features that would be irrelevant to the Wholesale Electricity Market. For example, because a single-region network model is proposed there would be no need to implement the mechanisms used in the National Electricity Market to support a multi-region network model.

The following sections discuss features of the proposed design, including the more material effects on stakeholders and where variations from National Electricity Market concepts and processes are expected. While stakeholders are invited to provide submissions on any aspect of the proposed design, the Electricity Market Review has highlighted several questions in this chapter on which it seeks specific comments from interested stakeholders.

5.2 Participant and facility classes

It is proposed to amend the Wholesale Electricity Market Rules to adopt as far as practicable the participant and facility registration classes and associated terminology of the National Electricity Market.

It is expected that generators and customers registered with the Australian Energy Market Operator under the Wholesale Electricity Market Rules will be deemed to be Registered Participants for the purposes of Chapters 5, 5A, 6, 6A and 7 of the National Electricity Rules. However, even though the Wholesale Electricity Market Rules will continue to allow for the registration of any network connected to the South West Interconnected System, only Western Power's transmission and distribution networks will be subject to economic regulation under the national framework on its commencement in Western Australia.

For many participants the changes will involve little more than modification of naming conventions. For example, in the Wholesale Electricity Market a 'Scheduled Generator' (facility) is registered to a 'Market Generator' (participant), while in the National Electricity Market a participant is registered as a 'Scheduled Generator' in respect of its (registered) 'scheduled generating unit'.

It is proposed that the participant and facility registration processes should also be aligned as closely as possible with those operating in the National Electricity Market, while taking into account any Wholesale Electricity Market-specific requirements such as those associated with the Reserve Capacity Mechanism. Details of the integrated processes will be developed in consultation with stakeholders during the implementation phase. It is expected that this phase will also include a review of standing data requirements for the new and amended registration classes.

The following sections assume that the reader has some familiarity with the registration classes in both the National Electricity Market and the Wholesale Electricity Market.[48]

5.2.1 Network definitions and registration classes

It is proposed that the Wholesale Electricity Market adopt the network registration classes and supporting terminology used in the National Electricity Market.

The National Electricity Market distinguishes between transmission and distribution systems and between transmission and distribution network operators (referenced as network service providers).

[48] For further details of the Wholesale Electricity Market registration classes see http://wa.aemo.com.au/docs/default-source/Electricity-Market/wem-design-summary-v1-4-24-october-2012.pdf?sfvrsn=0 (for a high level overview) or Chapter 2 of the Wholesale Electricity Market Rules. For further details of the National Electricity Market registration classes see AEMO National Electricity Market (for a high level overview) or Chapter 2 of the National Electricity Rules.

The distinction is necessary because transmission and distribution network service providers have different functions and obligations under Chapters 5, 5A, 6, 6A and 7 of the National Electricity Rules, with formal interactions prescribed between the two roles (for example distribution network service providers are considered to be customers of transmission network service providers). Further, the National Electricity Market settlement processes treat transmission-connected points differently from distribution-connected points.

Some changes to the National Electricity Rules definitions will be required, for example to change references to the national grid to references to the South West Interconnected System. Definitions that are not relevant to the Wholesale Electricity Market will not be adopted – for example, the use of a single-region network model means that the Market Network Service Provider class will not be needed, as it relates to the provision of interconnectors between regions.

5.2.2 Generators and generating units

Classification framework

It is proposed that the National Electricity Market classification system for generating units be adopted in the Wholesale Electricity Market. This classification system requires each generating unit to be classified as:

- either scheduled, semi-scheduled or non-scheduled; and
- either market or non-market.

A market scheduled generating unit is equivalent to a Scheduled Generator in the Wholesale Electricity Market, while a market semi-scheduled generating unit is equivalent to a Non-Scheduled Generator. The other classification options referenced above have no direct equivalents in the Wholesale Electricity Market Rules.

In the National Electricity Market, a generating unit with a nameplate rating of 30 MW or more is in most cases required to register as a scheduled or semi-scheduled generating unit and participate in the central dispatch process. The corresponding threshold in the Wholesale Electricity Market is 10 MW, a level that reflects the smaller size of the South West Interconnected System and its greater sensitivity to the actions of individual generating units. As there appears to be no justification to move to a higher threshold, it is proposed that the current 10 MW threshold for participation in the central dispatch process be retained.

Currently registered generating units with a nameplate capacity less than 10 MW are subject to less stringent communications requirements for the receipt and acknowledgement of dispatch instructions than larger generating units. This allows small generators to avoid potentially high communications costs relative to the size of their operations. This arrangement may not be supportable in the new energy market, as the alternative communication methods used for small generators in the Wholesale Electricity Market are likely to be too slow and unreliable for participation in an automated central dispatch process with a five-minute dispatch cycle.

Registration of small generating units as non-scheduled may allow generators to avoid the additional costs of participation in the central dispatch process, provided that there are no adverse effects on power system security. A Non-Scheduled Generator may however be required to comply with some of the obligations of a Scheduled Generator or Semi-Scheduled Generator, if the Australian Energy Market Operator considers this is necessary for any reason. Classification as a non-scheduled generating unit may also affect the generator's eligibility for Capacity Credits under the Reserve Capacity Mechanism, as discussed later in this chapter.

Under the proposed arrangements each generating unit would also be classified as either a market generating unit or a non-market generating unit. A generating unit would be classified as non-market if its generation was purchased in its entirety by the Local Retailer[49] or by a Customer located at the same connection point. Non-Market Generators would not receive any payment from the Australian Energy Market Operator for their output. Non-market generating units are in some respects similar to the 'unregistered' generating units serving Intermittent Loads in the Wholesale Electricity Market, and the concept may have some potential use in representing Intermittent Load arrangements in the future market.[50]

It is also proposed to adopt the National Electricity Market provisions that support the classification of market generating units as ancillary service generating units. Classification as an ancillary service generating unit allows the unit to participate in the competitive frequency control ancillary service markets. These provisions would replace the current arrangements for the registration of Load Following Ancillary Service (LFAS) Facilities[51].

Obligations to register and criteria for exemption

Under the Wholesale Electricity Market Rules a person that owns, operates or controls a generating system with a rated capacity less than 10 MW is not required to register in the market or seek a registration exemption from the Australian Energy Market Operator.

In the National Electricity Market, all generating units connected to the national grid (including small rooftop photovoltaic systems) are obliged to register unless exempted by the Australian Energy Market Operator. The Australian Energy Market Operator is able to set guidelines for exemptions and define blanket criteria for exemptions, which it has done for units with a nameplate rating less than 5 MW. Generating units with a nameplate rating between 5 and 30 MW may apply for and be granted exemptions under certain circumstances.

It is reasonable to argue that the Australian Energy Market Operator should be responsible for determining generator exemption criteria as it appears best placed to determine which generating units it needs to be aware of. However, any changes to the existing exemption criteria could have a material effect on small generators connected to the South West Interconnected System.

[49] See section 5.2.4 for more information about Local Retailers.
[50] See section 5.2.5 for further discussion of Intermittent Loads.
[51] An LFAS Facility is a facility that is able to participate in the current market for load following ancillary services.

The current Australian Energy Market Operator guidelines[52] would require persons with generating units in the 5 to 10 MW range (who are currently exempt) to register or seek an exemption, while the criteria for automatic exemption appear to prevent the purchase of an exempt generating system's output by a retailer that is not the Local Retailer.[53]

Western Power is unable to confirm exactly how many unregistered generating units with a nameplate rating between 5 and 10 MW are connected to the South West Interconnected System, but based on the information available it appears that there are very few, if any, unregistered generating units exporting to the South West Interconnected System at this level.

Lowering the registration threshold would provide better information to the Australian Energy Market Operator about the location and characteristics of smaller distributed generators. This information is likely to be even more valuable in a smaller system like the South West Interconnected System, where the effect of a generating system sized between 5 and 10 MW would be greater; it may also be more important in future if other reforms lead to an increase in the number of such facilities. On the other hand, the requirement to register or seek an exemption imposes administrative and cost burdens on small generators and so any lowering of the registration threshold would need to be justifiable in terms of market benefits.

There appear to be several options, including:

- retaining the current threshold prescribed in the Wholesale Electricity Market Rules (10 MW rated capacity);
- reducing the threshold in the Wholesale Electricity Market Rules to 5 MW, which would better align with the current Australian Energy Market Operator's guidelines while retaining a firm threshold for automatic exemption in the Wholesale Electricity Market Rules; or
- adopting the National Electricity Market arrangements, under which no automatic exemption threshold would be set in the Wholesale Electricity Market Rules and the Australian Energy Market Operator would be responsible for the determination of any blanket exemption criteria.

Request for comment – submissions are encouraged from stakeholders regarding whether, and if so how, automatic exemption criteria should be defined for the registration of generating units connected to the South West Interconnected System.

Aggregation of generating units

Clause 2.2.7(i) of the National Electricity Rules allows the registration of two or more generating units as one semi-scheduled generating unit, if the generating units are connected at a single site with the same loss factors, have an individual capacity of not more than 6 MW and have similar energy conversion models.

[52] Available at AEMO Classification and Exemption Guides: http://www.aemo.com.au/About-the-Industry/Registration/How-to-Register/Exemption-and-Classification-Guides

[53] In practice this restriction does not appear to be applied to small rooftop photovoltaic systems.

Clause 3.8.3 of the National Electricity Rules permits further aggregation of semi-scheduled generating units for the purposes of dispatch, provided that they are connected at a single site with the same loss factors, are operated by a single Semi-Scheduled Generator and will not adversely affect power system security or the operation of control systems (such as automatic generation control systems). These requirements would not prevent the classification of hybrid intermittent facilities, for example comprising a mixture of wind turbines and photovoltaic units.

Clause 3.8.3 also permits the aggregation of scheduled generating units under similar conditions for the purposes of dispatch.

It is proposed that these aggregation provisions be adopted for use in the Wholesale Electricity Market. The Electricity Market Review intends to work with the Australian Energy Market Operator and market participants during the submission period for this position paper to assist market participants to understand their aggregation options under the proposed new market arrangements.

Eligibility for certified reserve capacity

It is anticipated that reserve capacity certification will be undertaken at the dispatchable generating unit level. Only market generating units would be eligible for Capacity Credits.

No changes are proposed in this position paper to the current certification requirements under the Reserve Capacity Mechanism for scheduled and semi-scheduled generating units.

It is proposed that non-intermittent generating units should be classified as scheduled generating units and participate in the central dispatch process to be eligible for Capacity Credits, to ensure that the capacity paid for is made available to the market. This means that while a non-intermittent generating unit with a nameplate capacity less than 10 MW would be eligible for classification as a non-scheduled generating unit, it would be ineligible for Capacity Credits if it did so.

However, it is expected that a small intermittent generator[54] will seek to generate as much as it can and so its inclusion in the central dispatch process would not be needed to ensure its active participation in the market. Classification as a non-scheduled generating unit may constitute a more efficient option for small intermittent generators, as it would allow the generator to avoid the communications and other operational costs of participation in the central dispatch process.

It is therefore proposed that a generator with a small, intermittent generating unit should be eligible for Capacity Credits regardless of whether that generating unit is classified as semi-scheduled or non-scheduled.

[54] That is, with a nameplate capacity less than 10 MW.

Determination of the financially responsible market participant

Under the proposed market registration arrangements, the financially responsible market participant[55] for a market generating unit would be the person who registered as a Generator with the Australian Energy Market Operator and classified the generating unit as a market generating unit. The financially responsible market participant would not be required to be the holder of the connection agreement with Western Power for the relevant connection point. However, it is proposed that only the financially responsible market participant for a connection point should be eligible for Capacity Credits for the capacity of that generating unit.

5.2.3 Small Generation Aggregators

In the National Electricity Market a Small Generation Aggregator may act as the financially responsible market participant for one or more small generating units that have previously been exempted from registration. This allows the small generating units to participate in the market and be paid the spot price for their energy. The individual generating units require interval metering and must have a separate metering installation that does not also measure general consumption at the site, so that the construct cannot be used to bypass the normal licensing arrangements for customer loads or to avoid network use of system charges.

The market generating units classified by a Small Generation Aggregator do not participate in the central dispatch process and so would be unlikely to be eligible for Capacity Credits, as they would be non-scheduled but not necessarily intermittent. This, combined with the low energy price caps in the Wholesale Electricity Market and the need for separate interval metering, may limit the value of this option to potential small generators.

The Small Generation Aggregator concept could be extended to the Wholesale Electricity Market without material system costs, as the participant class is already supported in the Australian Energy Market Operator's market systems. However, substantial effort would be needed to establish the necessary governance framework for these participants. Given these considerations the Small Generation Aggregator concept is not proposed for inclusion in the initial new market design.

5.2.4 Customers and Loads

It is proposed that the current Wholesale Electricity Market customer and load classes be replaced with an extended version of the customer and load classes used in the National Electricity Market.

The National Electricity Rules require the division of its distribution systems into 'local areas', each of which is assigned to a Local Retailer. The Local Retailer is responsible for any franchise loads in its local area (if they exist) and is financially responsible for any energy flows into or out of its local area that are not allocated to other market participants. The Local Retailer concept is used in the settlement of contestable loads within a distribution system, including where full retail contestability applies.[56] For the initial implementation it is proposed that a single local area be defined for the South West Interconnected System, with Synergy as its Local Retailer.

[55] The financially responsible market participant for a market generating unit is the party who is paid by AEMO for the generation sent out from the unit's connection point (and who must pay AEMO for any energy purchased through that connection point).

[56] For further details of the settlement method see section 5.10.2.

The proposed amendments would replace the current Wholesale Electricity Market framework (under which a load is either a Non-Dispatchable Load, a Dispatchable Load or an Interruptible Load) with the National Electricity Rules framework (under which a load may optionally be classified as a scheduled load[57] and/or an ancillary service load).[58]

It is acknowledged that in the short term very few, if any, loads are likely to be classified as scheduled loads. However, the inclusion of scheduled loads in the new market design is still proposed as the concept is already supported in the Australian Energy Market Operator's market systems and has the potential to become increasingly relevant as the cost of battery storage technologies decreases. It is anticipated that existing Interruptible Loads will be classified as ancillary service loads in the new market and continue to provide spinning reserve through the new frequency control ancillary service markets.

Some modifications and extensions will be required to ensure that the current level of flexibility offered to loads in the Wholesale Electricity Market is not lost. Changes will be required to:

- support the registration of Demand Side Programmes and their Associated Loads;
- continue to allow 'first-tier' loads (that is distribution-connected loads supplied by the Local Retailer) to provide ancillary services, participate as scheduled loads and participate in Demand Side Programmes (provided they meet the relevant technical criteria); and
- continue to allow a participant other than the financially responsible market participant to classify a load as an ancillary service load or as an Associated Load of a Demand Side Programme.[59]

It is proposed that the Wholesale Electricity Market Rules should support the aggregation of ancillary service loads, as do the National Electricity Rules. It is expected that the specific technical requirements for the provision of ancillary services by aggregated loads will be developed by the Australian Energy Market Operator in consultation with stakeholders as the need arises.

5.2.5 Intermittent Loads

The Intermittent Load provisions in the Wholesale Electricity Market have no direct equivalent in the National Electricity Rules. However, examples of complex private networks with 'behind the fence' generation exist in the National Electricity Market, and there are several mechanisms used in that market (for example the provisions for non-market generating units and the processes established to support sites with complex metering arrangements) that could potentially be adapted to help manage Intermittent Load arrangements in the Wholesale Electricity Market.

57 A scheduled load is a load that is able to participate in the central dispatch process and adjust its consumption levels in response to dispatch instructions. Market Customers submit dispatch bids for their scheduled loads that indicate the proposed consumption levels for the facility at different spot prices. No bonus payments are made to the Market Customer for reducing its consumption – rather, the benefit is in avoiding high spot prices.

58 An ancillary service load is a load, or aggregation of loads, that can participate in one or more of the frequency control ancillary service markets.

59 This requirement is consistent with changes proposed in a rule change request currently under consideration by the Australian Energy Market Commission (ERC0186: Demand Response Mechanism and Ancillary Services Unbundling). For further details see AEMC - Demand Response Mechanism and Ancillary Services Unbundling available at: http://www.aemc.gov.au/Rule-Changes/Demand-Response-Mechanism

No justification has been found for the existing Intermittent Load arrangements to be abolished when the new energy market commences, although some changes will be needed to address existing design concerns[60], avoid excessive implementation costs and ensure that dispatch efficiency and power system security are not compromised. The Electricity Market Review is working with the Australian Energy Market Operator, Western Power and affected participants to determine how best to incorporate Intermittent Loads into the proposed market design. It is proposed that the new arrangements should:

- not require excessive implementation or ongoing support costs;
- not over-complicate or prevent the safe and efficient dispatch of the power system;
- ensure that a registered participant assumes formal market responsibility for meeting any obligations relating to the generating units serving an Intermittent Load under the Wholesale Electricity Market Rules;
- allocate to the generating units serving an Intermittent Load a share of spinning reserve costs proportionate to their potential effect on the supply/demand balance following a contingency, to be paid by the responsible participant;
- require the generating units serving an Intermittent Load to be included on the Equipment List (if sufficiently large) and the responsible participant to comply with the associated outage scheduling and reporting obligations for those units; [61]
- ensure that the Intermittent Load capacity used in the calculation of Individual Reserve Capacity Requirements accurately reflects the Australian Energy Market Operator's reasonable expectation of what the Intermittent Load may draw from the South West Interconnected System as the result of a forced or planned outage of its generating units; and
- not permit an Intermittent Load to be served by a generating system at a remote location.[62]

5.2.6 Treatment of storage facilities

No new registration classes to support commercial battery (or indeed other) storage facilities are proposed at this time. Based on the discussion paper *Integration of Energy Storage: Regulatory Implications* published by the Australian Energy Market Commission on 9 October 2015[63] and preliminary discussions with the Australian Energy Market Operator, it appears that the current registration classes used in the National Electricity Market (which already support pumped hydro storage facilities) should be sufficient in the short to medium term to support the participation of such facilities in the Wholesale Electricity Market.

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60 For example around the accuracy of Intermittent Load capacity declarations and the allocation of spinning reserve costs.

61 The Equipment List is a list of equipment comprising, or connected to, the South West Interconnected System that is required to be subject to outage scheduling by System Management. The list is maintained by System Management in accordance with clause 3.18.2 of the Wholesale Electricity Market Rules. A generating unit with a nameplate capacity of 10 MW or more would typically be included in the Equipment List.

62 As currently permitted under clause 2.30B.11 of the Wholesale Electricity Market Rules. This option has never been used and would be likely to add an unnecessary degree of complexity to the new market design.

63 Available at: http://www.aemc.gov.au/Major-Pages/Technology-impacts/Documents/Integration-of-Storage-Discussion-Paper.aspx.

However, the Electricity Market Review acknowledges that this is a rapidly developing area and that reviews underway in the national market may lead to recommendations for changes that may also be beneficial in the Wholesale Electricity Market. In particular, as the cost of battery storage technology reduces it will be important to ensure that the registration requirements are sufficient to support power system security while avoiding any unnecessary barriers to the participation of these facilities in the market.

It is proposed that storage facilities capable of exporting energy into the South West Interconnected System be regarded as generating units and therefore subject to the same registration obligations as other generating units with a similar nameplate capacity. It is expected that larger facilities that store energy drawn from the grid in batteries for later resale to the market would need to be registered as both a generating unit and a load, to ensure the facility incurs its fair share of network use of system charges.

5.2.7 Intending Participants

It is proposed that the National Electricity Market concept of Intending Participants be adopted in the Wholesale Electricity Market. A person may register with the Australian Energy Market Operator as an Intending Participant on the basis that it intends to become a Registered Participant (e.g. a Generator, Customer or Network Service Provider). It is expected that the concept could be usefully employed to support the certification of proposed new generating units, replacing the current approach under which participants are required to 'register' a 'new facility name' before applying for certified reserve capacity.

5.2.8 Other classifications

Several other changes to the Wholesale Electricity Market participant classifications are expected. Most of these changes are required to support other reforms being progressed by the Electricity Market Review. While some changes will be aligned with the introduction of the new energy market arrangements, others are expected to be implemented well before this time. A summary of the expected changes is provided below.

- The Independent Market Operator is expected to be abolished by mid-2016. Responsibility for the Independent Market Operator's compliance functions is expected to be transferred to the Economic Regulation Authority, while other roles and responsibilities to support the rule-making function will be separately transferred to the Economic Regulation Authority.
- The System Management role is expected to be abolished following the proposed transfer of System Management's functions to the Australian Energy Market Operator. The separation of the system management role from Western Power is also expected to require the establishment of System Operator and Distribution System Operator roles in the Wholesale Electricity Market, based on the corresponding roles in the National Electricity Market.

- The reforms being progressed by the Market Competition workstream of the Electricity Market Review include the establishment of the Australian Energy Market Operator as the new retail market operator for the South West Interconnected System, under Chapter 7 of the National Electricity Rules. While the Australian Energy Market Operator will act as both the wholesale market operator and retail market operator for the South West Interconnected System, it will do so under separate regulatory instruments, and so it is likely that the creation of a distinct Retail Market Operator role in the Wholesale Electricity Market Rules will be required. This role, which would replace the current Metering Data Agent role, would be responsible for the provision of metering registry data (NMI Standing Data) and settlement ready metering data to the Australian Energy Market Operator, to use in its wholesale market operator role for market settlement. These changes are currently expected to coincide with the implementation of the new market arrangements on 1 July 2018.
- The Wholesale Electricity Market Rules may also need to support the registration of Metering Coordinators[64], unless a more preferable arrangement for registration of Metering Coordinators for connection points in the South West Interconnected System is identified.

At this time, no other National Electricity Market registration classes are expected to be required in the Wholesale Electricity Market.

5.3 Ancillary Services

5.3.1 Frequency Control Ancillary Services

It is proposed that the current load following, spinning reserve and load rejection reserve ancillary services be replaced by arrangements based on the frequency control ancillary services of the National Electricity Market.

The exact service definitions and technical requirements will be finalised during the implementation phase, once the frequency operating standards that are to apply in the South West Interconnected System from 1 July 2018 are confirmed.[65] This is because the services must be tailored to achieve the frequency levels and restoration timeframes prescribed in the standards.

At this stage it is expected that the Wholesale Electricity Market will adopt the same eight services that are used in the National Electricity Market, namely:

- regulating raise and regulating lower services - replacing the current load following services;
- fast, slow and delayed (contingency) raise services – replacing the current spinning reserve service; and

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[64] The Metering Coordinator role was introduced to the National Electricity Market through the recent rule change Expanding competition in metering and related services (see AEMC - Expanding competition in metering and related services for details) available at: http://www.aemc.gov.au/Rule-Changes/Expanding-competition-in-metering-and-related-serv

[65] The frequency operating standards for the South West Interconnected System are currently contained in Western Power's *Technical Rules*, which will be abolished as part of the proposed move to the national framework for network regulation. The framework for the determination of power system security standards, including the frequency operating standards, is being considered by the Western Australian Reliability Panel project of the Electricity Market Review.

- fast, slow and delayed (contingency) lower services – replacing the current load rejection reserve service.

Minor timeframe adjustments to some services may be needed to reflect differences in the South West Interconnected System frequency operating standards from those applying to the national grid.

In general, the new services would perform the same functions as those being replaced in the Wholesale Electricity Market. However, it is proposed that the new delayed raise service be designed to support full restoration of system frequency following a single contingency event. The current spinning reserve service is more limited, covering only 70 per cent of the largest credible contingency; System Management relies on fast-start units in the Synergy portfolio if the online reserves are insufficient to return system frequency to the normal band. Synergy receives no explicit compensation for providing this fast-start capability. Extending the contingency raise services in this way would ensure that Synergy is adequately compensated and would facilitate competition for the provision of this service.

As in the National Electricity Market, co-optimised markets with a five-minute dispatch and settlement interval would be used to procure the frequency control ancillary services. Participation in these markets would be optional except for Synergy, which due to its dominant market position would be required to remain the default provider of these services. It is proposed that the service provision requirements be technologically neutral, for example allowing loads or aggregations of loads that are able to meet the technical requirements to be classified as ancillary service loads and offered into one or more markets.

The new markets would replace the use of administered pricing arrangements (for Synergy) and ancillary service contracts (for other providers) for spinning reserve and load rejection reserve service. Any remaining ancillary service contracts for the provision of spinning reserve service would be terminated when the new markets commence.

The Australian Energy Market Operator would be responsible for the determination of service requirement quantities for each dispatch interval. It is expected that the methods and processes used would be similar to those used by the Australian Energy Market Operator for the National Electricity Market.[66] These methods and processes would continue to be subject to periodic external review, likely by the Economic Regulation Authority upon advice from the Reliability Advisory Committee.[67]

5.3.2 System Restart Ancillary Services

System restart ancillary services will continue to be provided under long term ancillary service contracts.[68] The implementation of the new market arrangements should not affect existing contracts for the provision of these services.

[66] Further information about the frequency control ancillary services operating in the National Electricity Market is available at: http://www.aemo.com.au/Electricity/Market-Operations/Ancillary-Services

[67] This review is within the five-yearly review of ancillary service requirements and standards. This is listed as in the "Proposed Power System Reliability Functions" in Appendix A of the Position Paper on the Proposed Design of a Reliability Advisory Committee in Western Australia, available at https://www.finance.wa.gov.au/cms/uploadedFiles/Public_Utilities_Office/Electricity_Market_Review/3%20February%202016%20-%20Position%20Paper%20on%20Design%20of%20Western%20Australian%20Reliability%20Advisory%20Committee.pdf.

[68] Known as ancillary service agreements in the National Electricity Market.

It is proposed that the Economic Regulation Authority would have responsibility for determination of system restart standards for the South West Interconnected System (upon the advice of the Reliability Advisory Committee).[69] The Australian Energy Market Operator (in its system manager role) will be responsible for determining the specific ancillary service requirements needed to meet the system restart standards.

Currently System Management seeks implicit approval of its expenditure on system restart ancillary service contracts from the Economic Regulation Authority, through the periodic process used to determine the value of the Cost_LR parameter (this parameter covers the administered price component of ancillary service payments for load rejection reserve, dispatch support and system restart[70]). There is, however, no explicit requirement for System Management to gain approval from the Economic Regulation Authority before entering into a system restart ancillary service contract. This limits the value of the three-yearly Cost_LR process as the market will be liable for any charges incurred under a contract regardless of whether or not the Economic Regulation Authority approves System Management's Cost_LR proposal.

It is proposed that the governance framework be amended to provide a more robust and timely approval process, under which the Australian Energy Market Operator would require approval from the Economic Regulation Authority before entering into a system restart ancillary service contract.

5.3.3 Network Support and Control Ancillary Services

It is proposed that the current framework for Network Control Services and Dispatch Support Services in the Wholesale Electricity Market be replaced by a framework based on the National Electricity Market arrangements for network support and control ancillary services.

The proposed changes will facilitate the proposed adoption of Chapters 5, 5A, 6 and 6A of the National Electricity Rules through the use of shared terminology, concepts and processes, and will also provide greater clarity to stakeholders about the purpose of and responsibility for these types of services in the Wholesale Electricity Market.

Under the National Electricity Rules, a network support and control ancillary service (or NSCAS) is defined as a service with the capability to control the active power or reactive power flow into or out of a transmission network to address an 'NSCAS need', being a requirement to:

- maintain power system security and reliability of supply of the transmission network in accordance with the power system security standards and the reliability standard; or
- maintain or increase the power transfer capability of that transmission network so as to maximise the present value of net economic benefit to all those who produce, consume or transport electricity in the market.[71]

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[69] See the Position Paper on the Proposed Design of a Reliability Advisory Committee in Western Australia for further details.

[70] The 'L' component in the Cost_LR parameter relates to load rejection reserve service, while the 'R' component relates to system restart service. See clauses 3.13.3B and 3.13.3C of the Wholesale Electricity Market Rules for details of the determination process.

[71] Additional details are available in rule 3.11 of the National Electricity Rules and at AEMO Network Support and Control Ancillary Services (NSCAS) Description and Quantity Procedure available at: http://www.aemo.com.au/Electricity/Market-Operations/Ancillary-Services/Network-Support-and-Control-Ancillary-Services-NSCAS-Description-and-Quantity-Procedure

It is proposed that the primary responsibility for the provision of NSCAS would lie with the Transmission Network Service Provider, as is the case in the National Electricity Market. The Transmission Network Service Provider may arrange for a network service[72] to be provided:

- using its own assets;
- as a paid (discretionary) service provided under a network support agreement; or
- as an unpaid (mandatory) service under a connection agreement, registered with the Australian Energy Market Operator as a performance standard.

Where the Australian Energy Market Operator needs to dispatch or monitor the status of a service, the Transmission Network Service Provider would be responsible for providing the Australian Energy Market Operator with any required information.

Rule 5.20 of the National Electricity Rules requires the Australian Energy Market Operator to prepare and publish an annual National Transmission Network Development Plan as part of its National Transmission Planner functions. Each National Transmission Network Development Plan includes identification of any upcoming requirements for additional NSCAS (or ‘NSCAS gaps’).

The proposed adoption of Chapter 5 of the National Electricity Rules excludes the extension of the Australian Energy Market Operator’s National Transmission Planner role to cover Western Australia. However, a formal process for the identification of NSCAS gaps that is not dependent on the Transmission Network Service Provider would improve transparency and avoid any potential conflicts of interest. For this reason it is proposed that the Wholesale Electricity Market Rules include a requirement for the Australian Energy Market Operator to publish an annual report identifying NSCAS gaps in the South West Interconnected System.[73]

NSCAS gaps are expected to be met by the relevant Transmission Network Service Provider, with the costs recovered through its normal regulated revenue. However, the National Electricity Rules allow the Australian Energy Market Operator to procure an NSCAS through an ancillary services agreement, where:

- a need for the relevant service within a five-year horizon has been identified in a published National Transmission Network Development Plan;
- the responsible Transmission Network Service Provider has not acquired a service or taken other action to meet the need within the specified timeframes; and
- the need still exists and the Australian Energy Market Operator considers it necessary to acquire NSCAS to prevent an adverse effect on power system security and reliability.

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[72] Which may be an NSCAS or another service required to meet the network performance requirements in schedule S5.1 of the National Electricity Rules or other regulatory instruments.

[73] The detailed requirements for the proposed report are currently under consideration by the Network Regulation work-stream of the Electricity Market Review.

The Electricity Market Review understands that the 'last resort' powers assigned to the Australian Energy Market Operator may occasionally be necessary in the National Electricity Market, for example where an NSCAS need relates to an interconnector and it is not clear which Transmission Network Service Provider should be responsible. However, no plausible examples have been identified to date of critical NSCAS gaps (that would threaten power system security) that could not reasonably be expected to be filled by the Transmission Network Service Provider. Further, the existence of a 'last resort' option may act as an incentive for the Transmission Network Service Provider to delay or avoid entering into a network service agreement to meet an identified NSCAS gap.

For these reasons, the Electricity Market Review does not propose to assign the Australian Energy Market Operator last resort powers under the Wholesale Electricity Market Rules to fill NSCAS gaps. Instead, if the Australian Energy Market Operator identified an NSCAS gap as a threat to power system security or reliability, the Transmission Network Service Provider would be expected to either take action to fill the NSCAS gap or else provide a reasonable explanation of why no action was required.

It is expected that the current contract for the provision of Dispatch Support Services by Synergy would terminate at the time the new market arrangements commence. Once the future system security and reliability standards for the South West Interconnected System have been confirmed it is expected that Western Power, the Australian Energy Market Operator and the Economic Regulation Authority would need to work together to identify what, if any, services provided by Synergy under this contract should be provided in future under a network support agreement.

5.3.4 Cost Allocation

Regulating services

It is proposed that the costs of the regulating (load following) services be allocated on a 'causer pays' basis, similar to that used in the National Electricity Market.[74] The current Wholesale Electricity Market cost allocation method does not reflect the extent to which different facilities contribute to the need for load following, and can undercharge some participants (e.g. volatile intermittent generators and scheduled generators that fail to comply with dispatch instructions) and overcharge others (e.g. large but very stable loads). The causer pays approach would provide participants with sharper incentives to limit their contribution to the overall regulation requirement.

The new cost allocation method should be implemented as soon as practicable after the start of the new markets (for example once sufficient historical data is available to support the required calculations).

[74] Details of the National Electricity Market cost allocation method for regulating services are available in clause 3.15.6A of the National Electricity Rules and at AEMO Ancillary Services Causer Pays Contribution Factors available at: http://www.aemo.com.au/Electricity/Market-Operations/Ancillary-Services/Process-Documentation/Ancillary-Services-Causer-Pays-Contribution-Factors

Contingency raise services

Under the National Electricity Rules, the costs of the three contingency raise services are allocated to generators on a simple energy basis. In contrast, the Wholesale Electricity Market uses a ‘modified runway’ method that allocates spinning reserve costs in a manner more reflective of the relative contribution each generator makes to the spinning reserve requirement.

The modified runway method divides the costs of spinning reserve service in each trading interval into five blocks, each representing a MW output range. For each block, the assigned costs are divided equally among those generators whose output was within or above the relevant output range. Generators with higher output levels are typically allocated a higher share of spinning reserve costs under the modified runway method than they would under the method used in the National Electricity Market.

The relatively small size of the Wholesale Electricity Market means that spinning reserve requirements can potentially equal a large percentage of total system output, and so it is important to send accurate price signals to generators to avoid incurring inefficient spinning reserve costs. For this reason a change to the more simplistic energy-based allocation method is not proposed.

However, concerns have been raised by some stakeholders about the current modified runway method.[75] The use of blocks means that generators with output levels in the same block range are all charged equally, even though their relative contributions to the spinning reserve requirement may be quite different (e.g. two generators with output levels of 201 MW and 330 MW respectively will be charged equally). This can create perverse incentives for generators to limit the extent of their participation in the energy market.

To address this concern, it is proposed to implement a ‘full runway’ cost allocation method for these services, that is one that does not use fixed blocks but considers the contribution of each generator individually.

It is also proposed that consideration be given during the implementation phase to the basis on which generating systems servicing Intermittent Loads should contribute to spinning reserve costs.

Contingency lower services

Both the Wholesale Electricity Market and the National Electricity Market allocate the costs of contingency lower (load rejection reserve) services to customers on a simple energy basis.

No change is proposed to the current cost allocation method in the Wholesale Electricity Market at this time. Although it is acknowledged that other, more sophisticated methods might reflect the relative contribution of loads to the requirement more accurately, as long as the cost of the service is expected to remain low (with System Management having estimated the cost for the next three-year Allowable Revenue period to be zero) the expense of implementing such a method does not appear to be warranted.

75 For example in March 2014 Bluewaters Power presented a Pre Rule Change Proposal: Adjustment of Spinning Reserve Size Blocks (PRC_2013_014) to the Market Advisory Committee. For further details refer to the papers for the March 2014 and May 2014 Market Advisory Committee meetings, available at MAC 69 and MAC 71.

System restart ancillary services

Under the National Electricity Rules, the costs of system restart ancillary services are recovered from generators and customers in proportion to energy they generate/consume. In the Wholesale Electricity Market these costs are recovered from loads only, in proportion to energy consumed.

For some ancillary services the cost allocation method can be used to encourage market participants to act in a manner that reduces their contribution to the service requirement. However, this is not the case for system restart ancillary service, as the actions of individual market participants will have little, if any, effect on the overall service requirement.

Given that there are no particular ‘causer pays’ considerations, it would seem reasonable to adopt the National Electricity Market cost allocation method, as this would socialise the costs of the service more broadly across its beneficiaries and is consistent with the general principle of alignment with the national framework.

Request for comment – submissions on whether the Wholesale Electricity Market should adopt the National Electricity Market’s cost allocation method for system restart ancillary services are encouraged.

Network support and control ancillary services

It is proposed that all NSCAS in the Wholesale Electricity Market be provided by the Transmission Network Service Provider (Western Power). Western Power would pay for any NSCAS provided in accordance with a network support agreement and recover its costs through its normal regulated revenue arrangements.

5.4 Management of line losses

Loss factors are used in market dispatch and settlement processes to account for the energy lost from a power system due to electrical resistance and the heating of conductors.[76] Both the Wholesale Electricity Market and the National Electricity Market use static, annually revised loss factors.[77] Transmission loss factors are determined on an average marginal basis while distribution loss factors are determined on an annual average basis.

The basic methods for calculating loss factors in the two markets are similar. Both markets tend to apply individual loss factors to generators and large customers, and more generic average loss factors to smaller customers.

There are however some differences between the two markets, the most material of which relate to governance arrangements.

[76] An overview of the use of loss factors in the National Electricity Market is available at AEMO Treatment of Loss Factors http://www.aemo.com.au/Electricity/Market-Operations/Loss-Factors-and-Regional-Boundaries/Treatment-of-Loss-Factors The Wholesale Electricity Market provisions relating to loss factors are set out in section 2.27 of the Wholesale Electricity Market Rules and the Market Procedure for Determining Loss Factors.

[77] The National Electricity Market also uses dynamic marginal loss factors to account for losses on interconnectors between regions, but these are not expected to be relevant to the Wholesale Electricity Market as the new energy market is proposed to use a single-region network model.

Under the Wholesale Electricity Market Rules, Western Power is responsible for the annual determination of loss factors for the connection points on its networks. Loss factors are determined in accordance with the methods specified in the Market Procedure for Determining Loss Factors, which is developed and maintained by the Australian Energy Market Operator with the assistance of Western Power.

The loss factors calculated by Western Power are not subject to any formal approval process and are published by the Australian Energy Market Operator as they are received. However, a market participant may apply to the Australian Energy Market Operator for a reassessment of any transmission or distribution loss factor applied to its generators or loads. The Australian Energy Market Operator is required to process these applications and, if necessary, to conduct an audit of the relevant loss factor calculation. If the audit reveals a material error then Western Power is required to pay for the audit; otherwise the costs are borne by the market participant. Only one reassessment has been requested since the commencement of the Wholesale Electricity Market in 2006.

The Wholesale Electricity Market Rules and the Market Procedure together prescribe when and to what extent transmission and distribution loss factors are averaged over multiple connection points. For example, most connection points are allocated a system-wide average transmission loss factor, which effectively socialises the costs of transmission losses across the customers at those connection points.

Under the National Electricity Rules, the Australian Energy Market Operator is responsible for the calculation of transmission loss factors. By default, transmission loss factors are calculated for each connection point on the transmission network. However, subject to the Australian Energy Regulator’s approval of a request made by a distribution network service provider, a group of adjacent transmission connection points may be defined as a virtual transmission node, for which the Australian Energy Market Operator will calculate an average transmission loss factor. This allows the distribution network service provider to allocate a socialised transmission loss factor (similar to Western Power’s system-wide transmission loss factor) to some customers by allocating their distribution network connection points to the virtual transmission node.

Distribution network service providers in the National Electricity Market are responsible for the calculation of their distribution loss factors (as is the case in the Wholesale Electricity Market). Distribution loss factors must be approved by the Australian Energy Regulator before they are provided to the Australian Energy Market Operator for publication.

It is proposed that the Australian Energy Market Operator assume responsibility for calculating transmission loss factors for the new energy market. This is for three reasons:

- the Australian Energy Market Operator’s ‘forward-looking’ method is more sophisticated than its Wholesale Electricity Market counterpart, and is expected to produce more accurate loss factors when unexpected events occur or changes to the network or generator fleet are forecast;
- the Australian Energy Market Operator’s assumption of the role would help to future-proof the Wholesale Electricity Market design by facilitating the registration of multiple transmission network service providers in the Wholesale Electricity Market; and

- the change would be consistent with the general principle of seeking alignment with the national framework where practicable.

Western Power would continue to calculate the distribution loss factors for its distribution network, consistent with current practice in both markets.

It is also proposed that, consistent with the arrangements in the National Electricity Market, the Australian Energy Market Operator and Western Power should assume responsibility for the development, publication and maintenance of the methods used to calculate and allocate loss factors. The methods would be required to conform to a set of guiding principles outlined in the Wholesale Electricity Market Rules.

It is further proposed that the guiding principles for loss factor determination include consideration of the manner and extent to which transmission and distribution losses should be socialised across market participants. This is considered to provide the best governance framework to capture what is fundamentally a policy decision on wholesale electricity pricing for the South West Interconnected System.[78] The proposed approach should also remove the need to prescribe a formal approval process in the Wholesale Electricity Market Rules for the creation of virtual transmission nodes.

It is difficult to argue how removing the right of a market participant to seek a reassessment of its loss factors would lead to the long term benefit of consumers. Market participants have not abused this option and have little incentive to do so, as they are liable for the costs of an audit unless the loss factors are found to be materially in error.

It is therefore proposed that the current reassessment option be retained. It is however proposed that the auditing role be moved from the Australian Energy Market Operator to the Economic Regulation Authority, as it would be perverse for the Australian Energy Market Operator to be required to coordinate the reassessment of its own transmission loss factor calculations.

Provided that the reassessment option is retained, an additional requirement for distribution loss factors to undergo a formal approval process before publication is considered to be unnecessary and is therefore not proposed.

5.5 Reference node

In the Wholesale Electricity Market, the reference node is the network location at which the price of wholesale electricity is calculated. The National Electricity Market defines a reference node for each of its five regions.

Marginal loss factors are determined, relative to the reference node, for each major injection or withdrawal point of the network. Under the hub-and-spoke network model used in the National Electricity Market, constraint equations are said to be ‘orientated’ to the reference node.[79]

[78] It is expected that the guiding principles would be Protected Provisions and therefore any changes would be subject to ministerial approval.

[79] Australian Energy Market Commission, *Congestion Management Review, Final Report*, June 2008, p.56: notes that “*Constraint equations are correctly orientated if and only if there are no terms involving the* [regional reference node]”. Available at http://www.aemc.gov.au/getattachment/42a1dfd9-bf32-4bf1-bcc4-81dd8095dfc7/Final-Report-Appendix-A-An-introduction-to-congest.aspx.

The current reference node for the Wholesale Electricity Market is the Muja 330 kV busbar. This appears to have been selected as it is located at the largest source of generation in the South West Interconnected System and the interconnection of three transmission voltages at Muja terminal (330 kV, 220 kV and 132 kV). Electricity demand in the Muja region is very small when compared to the greater Perth metropolitan area.

The use of a generation centre as the reference node is atypical and is inconsistent with standard practice in the National Electricity Market, in which the reference node for each region is typically located at or near a major load centre (generally within the metropolitan area of the capital city).

There are philosophical, practical and equity-based reasons to consider a change in reference node for the South West Interconnected System.

- A marginally priced energy market sets the marginal price as the cost of an incremental unit of demand at the reference node. From a philosophical perspective, it makes sense that the reference node is located where an incremental unit of demand is more likely to be observed.
- Given that electricity typically flows towards the major load centre, generators closer to that load centre are more likely to be required to be constrained on if the network is congested. Setting the reference node at that load centre sees the costs of these generators reflected in the energy price and hence reduces the magnitude of constrained-on compensation. This approach is preferred because it better reflects the principles of marginal pricing and reduces the cost risks associated with higher levels of constraint payments.
- As constraint equations are orientated to the reference node, the location of the reference node at a generation centre could provide an advantage to generators that are connected at the reference node. These generators are unconstrained in terms of their ability to deliver energy to the reference node, at which the market is cleared, and so are not readily constrained in the market clearing engine – even if the network prevents their energy being transmitted to customers. This could result in inequitable treatment of generators and practical challenges for the system operator to constrain these generators, which may require tailored workarounds.

A change in reference node does not change the relativity of marginal loss factors between two locations on the network. These would scale up or down together according to the change in marginal loss factor between the old and new reference nodes.

For these reasons, the Electricity Market Review is considering shifting the reference node for the South West Interconnected System to a network location in the Perth metropolitan area, such as Southern Terminal. However, the Electricity Market Review understands that a change in reference node may result in costs and benefits to various parties given existing contractual and other arrangements, and therefore seeks the views of stakeholders in respect of such a change.

Request for comment – submissions are encouraged on the likely effects on stakeholders of a change to the reference node for the South West Interconnected System from the Muja 330 kV busbar to a network location in the Perth metropolitan region (such as Southern Terminal).

5.6 Basis for dispatch (as-generated or sent-out)

The energy output of a generator can be measured in two ways.

- Supply 'as-generated' is measured at the generator terminals, and represents the entire output from the generator.
- Supply 'sent-out' is measured at the generator's connection point, and represents only the electricity supplied to the market, excluding the generator's auxiliary loads (and any other loads behind the connection point).

The National Electricity Market dispatch processes are based on as-generated quantities. For example, the forecast generation requirement for a dispatch interval is calculated as an as-generated quantity and generators receive dispatch instructions containing as-generated target output levels. Energy settlement is based on sent-out energy quantities measured at the connection point. Any auxiliary load is effectively deemed to have been sold by the generator to itself at the market spot price.[80]

The Wholesale Electricity Market is designed around the concept of sent-out dispatch. For example, the balancing market is based on sent-out quantities, so that:

- generators specify sent-out quantities in their balancing submissions;
- the Balancing Merit Order uses sent-out quantities; and
- the dispatch instructions sent to independent power producer facilities specify sent-out dispatch targets.

Independent power producers are responsible for managing their generators and auxiliary loads to ensure that they achieve the sent-out target levels in their dispatch instructions.

However, System Management dispatches most facilities in the Synergy portfolio on an as-generated basis.[81]

The Reserve Capacity Mechanism is based on sent-out quantities, with generators being certified on the basis of their sent-out capacity. The obligations on generators holding Capacity Credits in relation to STEM and balancing submissions, outages and performance testing are all expressed in terms of sent-out quantities.

[80] Non-auxiliary loads that are not separately metered are also accounted for in this manner. However, such loads are often required to be metered and settled separately as a load for other reasons.

[81] For example, the set points sent to Synergy facilities operating under Automatic Generation Control are as-generated values. This use of as-generated dispatch is not in conflict with the Wholesale Electricity Market Rules, which are silent on how System Management should control the individual facilities within the Synergy portfolio.

Changing the Reserve Capacity Mechanism to be based on as-generated quantities is not a viable option because as-generated capacity does not provide an accurate estimate of the value provided to customers by a generator. For example, a generator with a 100 MW nameplate capacity and a 20 MW auxiliary load (at maximum output) provides less capacity value to the market than a generator with the same nameplate capacity but a 5 MW auxiliary load at maximum output, as the additional 15 MW of auxiliary load does not contribute to meeting peak customer demand. For this reason it is proposed that the Reserve Capacity Mechanism remains based on sent-out quantities.

At this time, retention of sent-out dispatch is preferred for the following reasons:

- during targeted consultation most stakeholders expressed a strong preference to continue using sent-out dispatch;
- sent-out dispatch places responsibility for managing the volatility of auxiliary loads on the generator rather than the market;
- as-generated dispatch would require changes to several Reserve Capacity Mechanism processes, including certification, testing, outage management, performance assessment and the calculation of capacity refunds – this would create additional implementation overheads and further increase the complexity of the Reserve Capacity Mechanism;
- as-generated dispatch would, to support the Reserve Capacity Mechanism, require the development of methods to estimate the auxiliary load of a generator producing a particular as-generated quantity, which may not be feasible for some generating systems with relatively unpredictable auxiliary loads or other behind-the-fence loads; and
- as-generated dispatch would require independent power producers, who may have already incurred material costs to comply with sent-out dispatch instructions, to make further changes to support compliance with as-generated dispatch instructions.

While further analysis is needed, at this stage the Electricity Market Review has not identified any specific problems that would prevent the retention of sent-out dispatch in the Wholesale Electricity Market. The preliminary advice provided by Australian Energy Market Operator representatives is that its NEMDE and Energy Management Systems should be capable of supporting sent-out dispatch in the Wholesale Electricity Market without requiring system changes or risking dispatch outcomes, provided that the Australian Energy Market Operator retains real-time visibility of the as-generated output of individual generating units.

However, a move to sent-out dispatch may result in costs and challenges for Synergy. As mentioned above, most Synergy generating units are currently dispatched on an as-generated basis and may require reconfiguration, or for some units an upgrade, of their control systems to support compliance with sent-out dispatch instructions. Further, individual sent-out SCADA points are not currently available for some facilities and may be difficult to install given the auxiliary load arrangements at some power stations.

For most other facilities the transition to sent-out dispatch using the Australian Energy Market Operator's systems appears much simpler, although questions have been raised about how the virtual scheduled generators associated with some Intermittent Loads can be represented within the NEMDE network model. However, the complexities in these cases relate more to how to manage the dispatch of generators serving both market and off-market load, rather than to the choice of as-generated versus sent-out dispatch specifically.[82]

The basis for dispatch is a critical decision as it affects (or potentially affects) many aspects of the new market design, including the development of NEMDE constraint equations for the South West Interconnected System, forecasting, outage management and assessment of compliance with reserve capacity obligations. A decision on the dispatch basis will therefore need to be made early in the implementation phase, to avoid risking the proposed implementation date of 1 July 2018.

The Electricity Market Review will continue to work with the Australian Energy Market Operator, System Management, Western Power and market participants to resolve this question during the submission period for this position paper. It is expected that given the current mixture of dispatch arrangements and facility configurations in the South West Interconnected System a pragmatic approach may be needed, to avoid the imposition of unnecessary costs on individual participants and the market in general.

5.7 Scheduling day processes and the STEM

As discussed in section 3.7, it is proposed that the STEM be retained in its current form, at least while the current market structure remains in place.

It is also proposed that:

- the current bilateral submission process and the concept of settlement against a participant's net contract position[83] be retained, to avoid unnecessary implementation costs for market participants;
- the requirement for market participants to submit Resource Plans be removed; and
- the STEM submission window be extended by one hour, from 9:50 am to 10:50 am.[84]

It is expected that the transfer of System Management's functions to the Australian Energy Market Operator will create additional opportunities to streamline the scheduling day processes, by removing the need for the formal interchange of information between the system and market operators.

[82] See section 5.2.5 for further details.

[83] The net contract position of a participant is the net quantity of energy that the participant has agreed to buy or sell in a trading interval through bilateral arrangements or STEM transactions. Participants are settled in the balancing market for the difference between their metered energy and their net contract position.

[84] The removal of Resource Plans and extension of the STEM submission window were also proposed in the Rule Change Proposal: Removal of Resource Plans and Dispatchable Loads (RC_2014_06) – see Rule Change- RC_2014_06 for details at: http://wa.aemo.com.au/home/imo/rules/rule-changes/under-development/rule-change-rc_2014_06

5.8 Planning and dispatch

As outlined in section 5.1, a principal feature of the proposed design is the implementation of real-time energy and frequency control ancillary service markets that are based on the National Electricity Market's spot market design and utilise the Australian Energy Market Operator's dispatch systems and processes as far as practicable.

It is proposed that during the implementation phase the processes and tools used in the National Electricity Market for short and medium term projected assessments of system adequacy (PASA), outage scheduling and reporting, forecasting, bidding and pre-dispatch, unit commitment, dispatch and the maintenance of power system security be reviewed and their design adapted for use in the Wholesale Electricity Market. The resulting design should align with the National Electricity Market as far as practicable, but will need to incorporate the following Wholesale Electricity Market-specific factors.

5.8.1 Generator outages

Some design changes may be necessary to reflect the different treatment of generator outages under the Reserve Capacity Mechanism.

- It is proposed to retain the requirement for generators holding Capacity Credits to participate in the outage planning process, and for scheduled outages of these facilities to be subject to the Australian Energy Market Operator's approval.[85] These requirements will need to be integrated into the projected assessment of system adequacy, pre-dispatch and forecasting processes.
- Consideration will need to be given to how to determine and record the availability of capacity resources that have long start up times or are subject to network constraints, to support the assessment of compliance with reserve capacity obligations and the calculation of capacity refunds.
- Details of generator forced outages will need to be captured in a manner that supports compliance monitoring and the calculation of capacity refunds.

5.8.2 Interventions and directions

The National Electricity Rules include provisions about how, and when, the Australian Energy Market Operator can intervene in the normal spot market processes and issue directions to participants to maintain power system security and reliability. For example, under certain circumstances the Australian Energy Market Operator may issue a direction to a generator that has previously declared itself unavailable, forcing that generator to operate – in these cases the generator is entitled to seek compensation from the market for its costs. Some of these provisions may be unnecessary or unsuitable for facilities that are subject to reserve capacity obligations that require availability under a set of defined circumstances.

[85] This requirement also applies to some other participants, for example generators with generating units that serve Intermittent Loads.

5.8.3 Gate closure and rebidding

Changes to the rules around gate closure and generator rebidding[86] may be needed, for example to reflect the effects of the Reserve Capacity Mechanism. As discussed in section 3.4, the Electricity Market Review considers that reduction of gate closure times to no more than 30 minutes is an integral component of the proposed reforms. However, the National Electricity Market takes this concept further and has no formal gate closure time.

Dispatch offers can be amended until about one minute before the start of each dispatch interval, when the process to calculate dispatch instructions and prices for that interval begins. Late rebidding is used for many reasons and is essential for several important functions in the National Electricity Market, such as the adjustment of dispatch offers when a generating unit experiences a forced outage.

The National Electricity Rules place restrictions on the circumstances under which generators may rebid. Nevertheless, concerns have been raised in the past about abuses of the late rebidding provisions by generators, although it is anticipated that rule changes made recently by the Australian Energy Market Commission may help to address many of these concerns.[87]

Having no formal gate closure may improve dispatch efficiency and would be consistent with National Electricity Market practice. On the other hand, late rebidding can increase the volatility of dispatch outcomes, which may discourage some generators from participating more actively in the market. Further, some of the reasons for late rebidding in the National Electricity Market may be irrelevant or invalid for generators that are subject to reserve capacity obligations or short run marginal cost bidding limits.

Further analysis is required to understand the role of late rebidding within the broader Wholesale Electricity Market design. To assist this analysis, the Electricity Market Review welcomes the views of stakeholders on the circumstances, if any, under which a formal gate closure limit should apply to generator rebids.

Request for comment – submissions are encouraged from stakeholders on the circumstances, if any, under which a formal gate closure limit should apply to generator rebids.

5.8.4 Other changes

It is expected that the new market design for the Wholesale Electricity Market will require several other variations from the National Electricity Market design. While the full list of variations will be determined during the implementation phase, three examples are provided below.

86 A rebid is an adjustment to the original dispatch offer or bid submitted by a market participant for a trading interval.
87 See AEMC - Bidding in Good Faith available at: http://www.aemc.gov.au/Rule-Changes/Bidding-in-Good-Faith. The new rules will commence on 1 July 2016.

- Some processes and tools used in the National Electricity Market may not be relevant to the Wholesale Electricity Market. For example, the Australian Energy Market Operator is required to produce regular Energy Adequacy Assessment Reports[88], which provide information on the effect of water shortages on scheduled generators (in particular those who operate hydro power schemes). A report of this nature would provide little or no value to the Wholesale Electricity Market.
- Systems and processes will be needed to support the dispatch of Demand Side Programmes.[89]
- To support compliance monitoring, a mechanism will be needed for generators that use both liquid and non-liquid fuels to notify the Australian Energy Market Operator of their proposed fuel type.

5.9 Pricing

5.9.1 Overview

The main features of the proposed pricing arrangements for the new energy and ancillary service markets include:

- calculation of ex-ante prices for energy (dispatch price) and each market ancillary service (ancillary service price) for each five-minute dispatch interval, using the same method as the National Electricity Market;
- calculation of a single spot price for each trading interval for energy settlement, defined as the time-weighted average of the six five-minute dispatch prices over the 30-minute trading interval;
- calculation of constrained-on compensation for generators that are dispatched to a level above that consistent with their dispatch offers;
- removal of constrained-off compensation; and
- alignment, where suitable, with the National Electricity Rule provisions in respect of setting and adjustment of prices in response to exception events.

Further details are provided in the following sections.[90]

5.9.2 Ex-ante calculation of dispatch and ancillary service prices

NEMDE calculates the dispatch price and ancillary services prices for each dispatch interval just prior to the start of the interval, as part of the process used to determine dispatch instructions. Each price is calculated as the cost of providing an incremental unit of the service at the Regional Reference Node.[91]

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[88] See AEMO Energy Adequacy Assessment Projection available at: http://www.aemo.com.au/Electricity/Resources/Reports-and-Documents/EAAP

[89] The detailed dispatch requirements for Demand Side Programmes are being considered as part of the Reserve Capacity Mechanism project within the Electricity Market Review.

[90] The calculation of dispatch payments for Demand Side Programmes is being considered separately by the Reserve Capacity Mechanism project of the Electricity Market Review, and so has not been included in this position paper.

[91] In the National Electricity Market separate prices are calculated for each of the five regions.

Dispatch and ancillary service prices are published by the Australian Energy Market Operator as soon as they are calculated. Once published the prices are only amended under exceptional circumstances, for example if the Australian Energy Market Operator determines that there was a manifestly incorrect input to the dispatch calculation process.

5.9.3 Calculation of spot prices and the 5/30-minute anomaly

While NEMDE calculates dispatch prices for each five-minute dispatch interval, the spot market is settled on a 30-minute basis as settlement-quality interval meter readings are not available for the shorter time periods.[92] The spot price for a trading interval is calculated as the time-weighted average of the six five-minute dispatch prices over the 30-minute trading interval.

The averaging process creates spot prices that can be much lower than one or more of the corresponding dispatch prices. This can create a problem for peaking generators that are dispatched for part of a trading interval, who risk being settled on the basis of a spot price that is lower than the generator's offer price and does not allow the generator to recover its short run costs. The risks for a peaking generator are increased by the ability of other generators to alter their dispatch offers after the start of a trading interval, which can greatly reduce dispatch prices for subsequent dispatch intervals and so the final spot price.

Average spot prices can also discourage loads from participating more actively in the market. A load will pay the average price across the whole trading interval, so that even if it can respond rapidly to a price spike it is unable to reduce its consumption in past dispatch intervals and so its ability to avoid the effect of high dispatch prices may be limited.

To address these concerns, Sun Metals Corporation recently submitted a rule change request to the Australian Energy Market Commission.[93] The request seeks the implementation of five-minute price settlement for generators and optional five-minute price settlement for loads. The method proposed is a variation of an option considered in 2002 by the Australian Energy Market Operator's precursor, the National Electricity Market Management Company. The option considered in 2002 was eventually rejected on the basis that it failed to provide a net positive benefit to the National Electricity Market with respect to market efficiency.

As a matter of principle, a generator that is required to operate should be compensated for its operating costs.[94] This is particularly the case for generators in the Wholesale Electricity Market with reserve capacity obligations, as they are required to make their capacity available to the market at all times, except during pre-approved maintenance periods.

For this reason it is proposed that the implementation phase include investigation of cost-efficient options to ensure that generators are not materially disadvantaged by the 5/30-minute anomaly under the new market arrangements.

[92] Interval meters, including those used in the South West Interconnected System, typically record distinct energy quantities for each 15-minute period. These quantities are accumulated by the relevant metering data provider to produce the 30-minute values used for market settlement.

[93] For further details see AEMC - Five Minute Settlement at: http://www.aemc.gov.au/Rule-Changes/Five-Minute-Settlement

[94] This principle also forms the rationale for the continuation of constrained-on compensation, as discussed in section 5.9.4.

5.9.4 Constrained-on compensation

In a market with a single reference node price, network limitations can result in situations where a generator is required to operate despite its offer price being higher than the reference node price. For example, a transmission line to a remote part of the network may reach its thermal limit, requiring energy to be generated locally to serve any additional demand above that limit. In this situation, the generator is considered to be constrained on.

This situation is handled differently in the current Wholesale Electricity Market compared to the National Electricity Market.

- In the Wholesale Electricity Market, a generator that is constrained on is paid constrained-on compensation to reflect its higher operating costs, consistent with the principle that a generator that is required to operate should be compensated for these costs.[95] Constrained-on compensation is funded by loads on the basis of their share of total consumption.

  The current mechanism was designed on the basis that it would be required infrequently, and it may under-compensate a generator that is constrained on for an extended period. This is because each trading interval is assessed in isolation, without considering whether the generator was constrained on in the previous trading interval.

- In the National Electricity Market, no explicit constrained-on compensation is paid. However, a generator that is forecast to be constrained on may declare itself unavailable. If the generator is still required to run, the Australian Energy Market Operator may issue it with a direction requiring it to operate. A generator that receives a direction is eligible to receive compensation, though it may not be suitable for it to receive its full offer price (which may be far above its short run costs due to the high market price cap). Instead, the initial compensation price is calculated relative to historical spot prices[96], with generators then able to apply to the Australian Energy Market Operator for additional compensation for lost revenue and additional net costs.[97]

The Electricity Market Review considers that the constrained-on approach used in the National Electricity Market is unsuitable for the Wholesale Electricity Market. Importantly, a generator holding Capacity Credits in the Wholesale Electricity Market is obliged to make itself available in the STEM and balancing market, and would be required to refund capacity payments if it declared itself unavailable. In addition, a generator's offer price in the Wholesale Electricity Market can be used as the basis for compensation payments, as it should be more reflective of the generator's operating costs due to the market power mitigation provisions in the Wholesale Electricity Market Rules.

95 A generator may be constrained on in response to a network constraint or as the result of forecasting error (where the final balancing price is different to the price suggested by the dispatch forecast) or dispatch error.

96 Rule 3.15.7 of the National Electricity Rules defines this price as "*the price below which are 90 per cent of the spot prices or ancillary service prices (as the case may be) for the relevant service … in the region to which the direction relates, for the 12 months immediately preceding the trading day in which the direction was issued*".

97 This process is detailed in rule 3.15.7B of the National Electricity Rules.

For these reasons, the Electricity Market Review proposes that constrained-on compensation be retained for the Wholesale Electricity Market, with a modified calculation to recognise that a generator may be constrained for multiple trading intervals. While the specific method of calculation would be determined during the implementation phase in consultation with stakeholders, preliminary discussions with the Australian Energy Market Operator indicate that there are several feasible options available for consideration.

It is proposed that the Australian Energy Market Operator would be required to publish data in respect of constrained-on compensation, including details of the trigger constraint, the generating unit(s) involved and the amount of compensation paid. This would provide transparency of costs and signal locations in the network that are congested, the costs of that congestion and opportunities for new investment to reduce costs to consumers.

It is acknowledged that compensation payments to address network constraints are unpredictable (and under some circumstances unrecoverable) expenses that are not really able to be hedged. However, other measures proposed in this position paper would be expected to reduce the incidence of constrained-on compensation, including:

- the proposed change to ex-ante pricing, which would remove the need for constrained-on compensation to address the effects of dispatch forecasting errors; and
- relocation (subject to further analysis) of the Reference Node to a load centre in the South West Interconnected System, which would be expected to reduce the likelihood of a binding constraint causing a generator to be constrained on out-of-merit.

5.9.5 Removal of constrained-off compensation

Under the proposed security-constrained market design, network constraints can lead to situations where a generator is not required to operate despite its offer price being lower than the dispatch price. For example, a transmission line from a remote area of the network may reach its thermal limit, restricting the energy that can be generated by one or more generators in that area. In these situations a generator is considered to be ‘constrained off’ out-of-merit.

The Electricity Market Review considers that, as a matter of principle, a generator that is constrained off by the security-constrained dispatch process should not be entitled to compensation from the market.

For this reason, it is proposed that constrained-off compensation should not be included in the new market design. This is consistent with the approach adopted in the National Electricity Market, where a constrained-off generator receives no payment for its failure to be dispatched.

5.9.6 Management of exceptions in the National Electricity Market

The National Electricity Rules include numerous provisions relating to the setting and adjustment of energy and ancillary service prices in response to exceptional events, for example where:

- a manifestly incorrect input to the central dispatch algorithm is identified;
- the Australian Energy Market Operator needs to intervene in the market and issue directions to participants;

- an administered price period occurs (through cumulative prices over a set period exceeding a defined threshold); or
- the spot market is suspended.

The National Electricity Rules also include provisions around the payment of compensation to participants following certain events, including for example an intervention event, administered price period or market suspension period.

It is proposed that these provisions be reviewed during the implementation phase to assess how and whether they should be adapted for use in the Wholesale Electricity Market. It is expected that while some of the provisions are likely to be suitable for inclusion in the Wholesale Electricity Market Rules, others may either be unnecessary or else require substantial amendment due to the effects of the Reserve Capacity Mechanism and the lower energy price limits in the Wholesale Electricity Market.

5.10 Metering and settlement

As mentioned previously, the State Government has decided to transfer the South West Interconnected System retail market operator role from Western Power to the Australian Energy Market Operator. At this stage, it is anticipated that the transfer of functions will coincide with the adoption of the national framework for network regulation and start of the new energy market arrangements on 1 July 2018.

It is expected that numerous changes will be needed to the current Wholesale Electricity Market settlement arrangements, to account for not only the new energy and ancillary service markets but also the proposed implementation of full retail contestability. The selection of the Australian Energy Market Operator as both wholesale and retail market operator provides opportunities to leverage its existing systems and processes, and in particular the Market Settlement and Transfer Solution (MSATS), to support wholesale market settlement under the new market arrangements.

The following sections discuss two material areas of difference between the metering and settlement arrangements in the Wholesale Electricity Market and National Electricity Market.

5.10.1 Settlement cycle timing considerations

Currently the Wholesale Electricity Market supports two distinct settlement processes.

The STEM is settled on a weekly basis. STEM settlement statements for a trading week (which begins at 8:00 am on a Thursday) are issued on the first business day after the end of the week, with settlement occurring two business days later. STEM settlement is expected to remain a weekly process under the new market arrangements.

All other market transactions are settled on a monthly basis, for trading months that begin at 8:00 am on the first day of a calendar month. Western Power is required to provide the interval metering data[98] for a trading month by its interval meter deadline, defined as the first business day of the second month following the trading month. (For example, the interval meter deadline for January 2016 is 1 March 2016.) A Non-STEM settlement statement is issued between three and five business days after the interval meter deadline for the trading month.

In contrast, the National Electricity Market has a single settlement process, based on weekly billing periods that begin at 12:00 am on a Sunday morning. Preliminary statements are issued within five business days of the end of the billing period, while the final statements used for settlement are issued within 18 business days of the end of the billing period.

The comparatively long delay in the Wholesale Electricity Market between the end of a trading month and its settlement is due to the current timeframes for the provision of interval metering data by Western Power. Interval meters are currently required to be read on a monthly basis, although most remotely read (type 1-4) meters are in practice read weekly.

The faster National Electricity Market settlement cycle is possible for two main reasons.

- The timing requirements for the provision of metering data for remotely read interval meters are much more demanding than in the Wholesale Electricity Market. For example, interval metering data for a billing period must be provided to the Australian Energy Market Operator for at least 98 per cent of remotely read interval meters by 5:00 pm on the second business day of the following week.
- For manually read meters, when a Metering Data Provider provides an actual reading to the Australian Energy Market Operator it is usually required to also provide a forward estimate reading for the next scheduled reading period. Forward estimates are used in the settlement calculations to cover periods for which an actual reading is not yet available.

Early availability of the vast majority of readings for larger meters and the use of forward estimates for smaller meters allows the National Electricity Market to have a much faster settlement cycle than the Wholesale Electricity Market. If similar obligations were placed on the Metering Data Providers for the South West Interconnected System, then it would be possible to move to a weekly cycle for Non-STEM settlement, either the same as or similar to the National Electricity Market settlement cycle. Advantages would be expected to include:

- a material reduction in prudential requirements for market participants; and
- potential efficiency gains for the Australian Energy Market Operator from the closer alignment of settlement processes between the two markets.

[98] Currently meter readings for accumulation meters are not used in the market settlement process.

However, the change also has potential disadvantages, including the following.

- The faster settlement cycle may adversely affect the cash flow of some participants, in particular retailers who may need to pay for energy consumed by their customers before those customers can be billed.
- More frequent settlement imposes an additional administrative burden on market participants, which can be particularly onerous for smaller participants.
- A change to a weekly settlement cycle would require changes to several Reserve Capacity Mechanism processes that assume a monthly settlement cycle, including the Capacity Credit allocation process and the calculation of Individual Reserve Capacity Requirements.
- The more demanding requirements for the provision of interval metering data for remotely read meters impose additional costs on a Metering Data Provider, as it is required to read more meters in a shorter timeframe and has less time to address any meter or communications problems that occur.[99]
- There is a risk that a faster settlement cycle could produce unreliable settlement outcomes if the more demanding deadlines for provision of metering data could not be met.

Another option, which might avoid some of these disadvantages, would be to retain a monthly settlement cycle but bring forward the settlement dates for each trading month to reduce the prudential burden on market participants.

The Electricity Market Review seeks the views of stakeholders on how, and whether, the Non-STEM settlement cycle timelines should be amended. At this stage there appear to be several options, including:

- retaining the existing timelines;
- adopting the settlement timelines used in the National Electricity Market;
- retaining a monthly settlement cycle but generating Non-STEM settlement statements earlier; or
- retaining the existing timelines for the initial implementation, but with the intention of moving to a faster settlement cycle once the reliability of the new metering arrangements had been demonstrated.

Request for comment – submissions from stakeholders are encouraged on how, and whether, the Non-STEM settlement timelines should be amended.

[99] Interval metering data is however also used for prudential monitoring in the National Electricity Market, and so the requirement for its early provision may be warranted regardless of the settlement cycle.

5.10.2 Settlement by difference and management of loss residues

The current *Electricity Industry (Metering) Code 2012* requires that all loads without interval metering are served by Synergy and are prohibited from transferring to another retailer.[100] For simplicity of wholesale market settlement, these loads are then treated as a single, Synergy-owned Notional Wholesale Meter.

It is expected that this prohibition will be removed as part of the proposed introduction of full retail contestability. This will require changes to the way that basic-metered and unmetered loads are accounted for in wholesale market settlement, as they will no longer be solely supplied by Synergy and it will not be possible to treat them as part of a single, Synergy-owned Notional Wholesale Meter.

The National Electricity Market uses a 'settlement by difference' approach to manage the energy settlement of non-interval metered loads connected to a distribution system.[101] Under this approach, energy entering each local area is recorded at the transmission/distribution system boundary. Settlement is then undertaken by assuming that all energy in the local area is to be billed to the Local Retailer, except for what is allocated to generators and other retailers (second-tier retailers) with connection points located within that local area.

Profiling is used for second-tier loads without interval meters to generate the notional 30-minute readings needed for trading interval settlement.

The Electricity Market Review proposes that the settlement by difference approach be adopted for use in the Wholesale Electricity Market. Settlement by difference offers established and proven methods for determining notional interval readings (profiles) for non-interval metered loads, and would allow the Australian Energy Market Operator to take advantage of its existing Market Settlement and Transfer Solution system, reducing implementation costs and risks.

The settlement by difference method generates settlement residues (loss residues), due to the way in which static marginal Transmission Loss Factors are used in the calculations. The loss residue for a trading interval is the difference between the total amount charged for energy consumed and the total amount paid for energy generated in that trading interval. The loss residues are normally expected to be positive, as in total loads are expected to be charged more for the loss-adjusted energy they buy than generators are expected to be paid for the loss-adjusted energy they sell. However, loss residues can be negative in some circumstances.[102]

In contrast, the current Wholesale Electricity Market settlement methodology does not calculate loss residues separately. Effectively the loss residues are obscured within the Notional Wholesale Meter and provide a windfall gain or loss to Synergy, depending on whether the loss residue is positive or negative.

Settlement by difference is likely to have at least some effect on Synergy's financial position. However, the Electricity Market Review considers that for reasons of equity and efficiency

[100] The prohibition is set out in clause 3.17 of the Electricity Industry (Metering) Code 2012, available at: http://www.slp.wa.gov.au/gazette/gazette.nsf/0/12CD08688E37922E48257ACC00233250/$file/gg225.pdf

[101] Individual transmission-connected loads must be interval metered and explicitly registered by a Market Customer with the Australian Energy Market Operator.

[102] For example, if due to changing circumstances the generation or load levels at a particular location materially differ from the levels assumed in the calculation of the static annual loss factors.

loss residues should be shared among consumers rather than allocated to an individual market participant, and so the current arrangements constitute an unwarranted cross-subsidy regardless of whether it is to Synergy's advantage or disadvantage. For this reason the proposal to change to settlement by difference is not dependent on the introduction of full retail contestability.

The Electricity Market Review commissioned analysis to estimate the magnitude of loss residues in the Wholesale Electricity Market using half-hourly network flow data provided by Western Power for the 12-month period from 1 March 2014 to 28 February 2015. This analysis suggested that total residues were around negative $9 million. The negative loss residue may be due to discrepancies between the published loss factors[103] and observed network losses or due to unmeasured demand that is not accounted for in the Western Power data set. In respect of the latter possibility, the analysis estimated that an additional load of 22 MW at the reference node would be sufficient to swing the aggregate loss residue to a positive value.

While in principle any loss residues should be allocated to consumers there are several ways in which this could be achieved, including those outlined below.

- The loss residues could be distributed by the Australian Energy Market Operator directly to market participants on the basis of their consumption share. This would allow positive loss residues to be used, to the extent they are available, to offset the cost of constrained-on compensation and any other charges that are socialised across loads. However, this approach would expose market participants directly to the risk of negative loss residues.
- In the National Electricity Market, intra-regional loss residues are allocated to the transmission network service provider, who must use those residues to offset network service charges. This allows the eventual allocation of the loss residues to consumers in a more regular and predictable manner, and in particular helps to avoid price shocks if on occasion the loss residues are negative.
- A hybrid approach could be adopted, whereby positive loss residues would be used to offset the costs of constrained-on compensation, with the remainder allocated to the transmission network service provider. Negative loss residues would be allocated to the transmission network service provider as in the National Electricity Market. This approach would reduce the direct exposure of market customers to these unpredictable and (for market customers) unavoidable costs, without imposing a new risk of negative loss residues.

Request for comment – submissions from stakeholders are encouraged on how loss residues collected by the Australian Energy Market Operator, due to the use of static marginal transmission loss factors and settlement by difference, should be allocated back to consumers.

[103] The analysis used the 2015-16 transmission loss factors published by the Australian Energy Market Operator at http://wa.aemo.com.au/home/electricity/market-information/loss-factors. These loss factors were calculated using data from the 12-month period covered by the loss residue analysis.

Removal of the prohibition on non-interval metered transfers will also require changes to the method used to calculate Individual Reserve Capacity Requirements, as the current method also assumes the existence of a single, Synergy-owned Notional Wholesale Meter.

6. Market power mitigation

The Wholesale Electricity Market is still far from fully competitive. While the dominant position of Synergy as both a generator and a retailer provides the most obvious example of market power, the network configuration and small size of the South West Interconnected System mean that many generators can hold locational market power during periods of network congestion.

Market power can be applied in several ways to influence pricing outcomes. These include, but are not limited to:

- withholding generation, to create conditions of shortage and so increase prices; and
- submitting offers at excessive prices.

To prevent potential market power abuses of the first kind, the Wholesale Electricity Market Rules require market generators with Capacity Credits to offer their available capacity into the STEM and balancing market.

Two mechanisms are used to prevent abuses of the second kind. Firstly, the market uses comparatively low energy price caps to limit generator offers into the STEM and balancing market. Secondly, the Wholesale Electricity Market Rules place additional limits on generator offer prices where the potential for market power abuse exists, through the short run marginal cost provisions set out in clauses 6.6.3 and 7A.2.17.[104]

The reforms proposed in this position paper will not prevent the existence of market power, but are expected to greatly increase transparency around the operation of the real-time markets and the dispatch of energy and ancillary services. This will help to prevent or expose any abuses of market power, and is expected to increase stakeholder confidence in the market and encourage greater levels of participation and competition.

No fundamental changes are proposed to the market power mitigation measures currently in place. However, some refinements may be needed to reflect specific design features of the new real-time markets and to provide greater clarity to market participants about their obligations.

6.1 Energy price limits

In capacity markets such as the Wholesale Electricity Market, it is expected that the highest cost peaking units will recover their fixed costs through capacity payments rather than energy market price spikes. For this reason, the energy price limits for the Wholesale Electricity Market are designed to recover only the short run costs of the highest cost peaking unit. Given the proposed retention of the Reserve Capacity Mechanism, the Electricity Market Review sees no justification for departing from this basic design principle.

[104] A similar limit on submissions to the LFAS Market is set out in clause 7B.2.15 – for further details see section 6.3.

The Wholesale Electricity Market currently uses two energy price limits: the Maximum STEM Price, which applies when gas is used by the highest cost peaking unit, and the Alternative Maximum STEM Price, which applies when liquid fuel is required to be used. Each price is set to a level that is expected to recover the short run average costs of the highest cost 40 MW open cycle gas turbine in the South West Interconnected System, for at least 80 per cent of dispatch cycles between 0.5 and 6 hours in length. The price limits are used in both the STEM and the balancing market.

The method used to calculate the energy price limits has changed little over recent years and is broadly supported by stakeholders.[105] It is acknowledged that the price limits may not always guarantee the full recovery of short run costs for all generators under all circumstances. However, in practice prices in the STEM and balancing market only very rarely reach the Maximum STEM Price. For example, during the period from the start of the balancing market on 1 July 2012 to the end of 2015, the Balancing Price reached the Maximum STEM Price in 50 trading intervals but never exceeded it, while STEM Clearing Prices never reached this level. Further, no market participant has ever presented evidence to an energy price limits review to show that the price limits were preventing it from recovering its short run costs.

Based on these factors, the Electricity Market Review does not propose any changes to the basic method for determining the energy price limits. However, the new markets may bring changes that could potentially influence the choice of some input assumptions. For example, the proposed reductions to gate closure and dispatch interval times may affect the criteria for selecting historical dispatch cycles for the analysis.[106] The Electricity Market Review therefore proposes that the Australian Energy Market Operator and the Economic Regulation Authority take the potential effects of the proposed market changes into consideration during future reviews of the energy price limits.

In the past, several stakeholders have suggested that only one energy price cap is needed in the Wholesale Electricity Market. This suggestion was considered by the Economic Regulation Authority in its 2013 review of the methodology for setting the Maximum Reserve Capacity Price and the Energy Price Limits in the Wholesale Electricity Market.[107] In its final report, the Economic Regulation Authority recommended the retention of the two energy price limits:

> “Whilst the Authority considers that in a competitive market, a single energy price cap (based on distillate fuel) alone would serve to mitigate the misuse of market power, the Authority considers the removal of the Maximum STEM Price will require some further examination as to the appropriateness of having a single cap and the potential impact on the effectiveness of the market, given the current stage of market development. The Authority is mindful of a number of reviews that are currently being undertaken in relation to the design of the WEM and the implementation of the merger between Verve Energy and Synergy.

[105] For example, all of the submissions received by the Independent Market Operator for the last four annual reviews have been supportive of the method used to determine the energy price limits. For further details see: http://wa.aemo.com.au/home/electricity/consultations/other-wem-consultation-documents-overview

[106] The proposed guidelines for the interpretation of the short run marginal cost provisions of the Wholesale Electricity Market Rules may also influence these choices; for further details see section 6.2.

[107] The Economic Regulation Authority is required under clause 2.26.3 of the Wholesale Electricity Market Rules to review the methodology for setting the Maximum Reserve Capacity Price and the energy price limits every five years. Details of the 2013 review are available at: https://www.erawa.com.au/electricity/wholesale-electricity-market/reviews/maximum-reserve-capacity-price-and-energy-price-limits-methodology-review

> This may result in some significant changes and implications for competition and market power in the WEM. Hence the Authority considers it is appropriate to retain the current arrangements of two price caps for the time being."[108]

The number of energy price caps is unlikely to have a material effect on the implementation costs for the new markets. However, the increased transparency of the new market arrangements may help to alleviate concerns about the potential for market power abuses if the Maximum STEM Price was removed. The Electricity Market Review therefore proposes that the Economic Regulation Authority reassesses the potential risks and benefits of a single energy price cap following the implementation of the proposed reforms on 1 July 2018.

6.2 Short run marginal cost and market power

As mentioned above, the Wholesale Electricity Market Rules place two specific obligations on market generators to prevent the submission of excessive offer prices into the STEM and balancing market.

Clause 6.6.3 limits generator offers into the STEM:

> "A Market Generator must not, for any Trading Interval, offer prices within its Portfolio Supply Curve that do not reflect the Market Generator's reasonable expectation of the short run marginal cost of generating the relevant electricity when such behaviour relates to market power."

Clause 7A.2.17 limits generator offers into the balancing market:

> "Subject to clauses 7A.2.3, 7A.2.9(c) and 7A.3.5, a Market Participant must not, for any Trading Interval, offer prices in its Balancing Submission in excess of the Market Participant's reasonable expectation of the short run marginal cost of generating the relevant electricity by the Balancing Facility, when such behaviour relates to market power."

According to economic theory, if the Wholesale Electricity Market was fully competitive then competition would prevent generators from pricing above their short run marginal cost. The short run marginal cost provisions are designed to replicate the efficient outcomes of a competitive market, by requiring generators with the potential to influence final prices to offer into the STEM and balancing market as if those markets were in fact fully competitive.

However, since market start concerns have been raised about the need for greater clarity on how these clauses should be interpreted, particularly as the terms "short run marginal cost" and "market power" are not defined in the Wholesale Electricity Market Rules.

[108] Economic Regulation Authority, *Review of methodology for setting the Maximum Reserve Capacity Price and the Energy Price Limits in the Wholesale Electricity Market*, September 2013, p. 30, available at: https://www.erawa.com.au/cproot/12036/2/Review%20of%20methodology%20for%20setting%20the%20MRCP%20and%20the%20EPLs%20in%20the%20WEM.pdf

In January 2008, the Economic Regulation Authority published two papers (a discussion paper and a technical paper) to assist market participants in the understanding of short run marginal cost. The papers set out to identify what costs may be included in a firm's short run portfolio supply curve calculation and how short run marginal cost may be estimated. An additional, simplified paper was published in December 2009.[109]

While the papers are a useful source of information for participants, they have no formal status under the Wholesale Electricity Market Rules and do not represent the official views of the Economic Regulation Authority. The papers were also published before the implementation of the balancing market and so their focus is limited to the preparation of offers for the day-ahead, portfolio-based STEM. As a result the papers do not address several concerns specific to the balancing market, such as:

- the different inter-temporal considerations created by the more dynamic balancing market timeframes;
- the requirement for participants with generation portfolios (excluding Synergy) to submit offers on an individual facility basis; and
- the ability for market power to influence not only clearing prices but also the prices paid for constrained-on compensation.

The lack of clarity around short run marginal cost obligations in the Wholesale Electricity Market was evident during the recent investigations undertaken by the Economic Regulation Authority into alleged breaches of clause 7A.2.17 of the Wholesale Electricity Market Rules by Vinalco Energy.[110] The investigation, although complicated by the method used in the Wholesale Electricity Market to calculate constrained-on compensation,[111] highlighted the need for a better understanding across the market of short run marginal cost in the context of generator dispatch offers, as well as greater clarity about the circumstances in which a generator may hold market power and what constitutes the abuse of market power.

The practical realities of an electricity market necessitate a pragmatic interpretation of short run marginal cost. For example:

- the short run marginal cost curve for many generators is U-shaped and cannot be represented by a monotonically increasing offer curve without some averaging;
- in a competitive market a generator would not typically seek to recover its start-up costs in a single dispatch interval – instead a generator would usually seek to recover these costs over multiple dispatch intervals, by adjusting its offer prices in accordance with its expected run times and operating levels; and
- the offering of multiple identical generating units at exactly the same offer prices could lead to perverse and inefficient dispatch outcomes.

[109] The three papers are available at: https://www.erawa.com.au/cproot/12036/2/Review%20of%20methodology%20for%20setting%20the%20MRCP%20and%20the%20EPLs%20in%20the%20WEM.pdf

[110] For details of the investigations see: https://www.erawa.com.au/electricity/wholesale-electricity-market/surveillance/investigation-on-vinalco-energy-pty-ltd

[111] The method, which is based on the calculation of theoretical energy scheduled for each trading interval, may under-compensate a generator that is constrained on for an extended period by underestimating the quantity of energy that is dispatched out-of-merit. This problem will be addressed in the new market design.

However, generators obviously need clarity of what this pragmatic interpretation comprises.

The Electricity Market Review proposes that the Wholesale Electricity Market Rules require the publication and periodic review of practical guidelines for interpretation of the short run marginal cost provisions. The Electricity Market Review proposes to develop the initial guidelines during the implementation phase, in consultation with the Economic Regulation Authority, the Australian Energy Market Operator and other stakeholders, with subsequent reviews to be undertaken by the Economic Regulation Authority.

The guidelines would assist generators to understand and comply with their bidding obligations and would also provide clarity on these obligations for the purposes of compliance monitoring and enforcement. It is expected that the guidelines would cover, among other things:

- the circumstances in which a generator may be deemed to hold market power (including consideration of factors such as market share, location, network constraints, technology and common ownership);
- guidelines for the formation of offers that comply with the short run marginal cost requirement, including:
  - clarification of the need to consider economic rather than accounting costs;
  - clarification of what costs may be included and what costs must not be included;
  - treatment of shutdown costs;
  - treatment of avoidable fixed costs such as start-up costs, including principles around the reasonable expectation of run times for different types of generating units under various circumstances;
  - treatment of operational risks, including outages and network constraints;
  - guidelines for forming unit commitment assumptions for larger portfolios containing a mixture of plant types;
  - guidelines for generators with multiple generating units of the same type, for example to avoid the infeasible dispatch of multiple units and to ensure individual units are not over or under-utilised;
  - treatment of fuel costs, for example for generators with take-or-pay contracts or limited fuel supplies;
  - how and whether the input assumptions used to form offer prices should vary between the STEM and the real-time market; and
  - the circumstances under which a generator should be expected to revise its real-time dispatch offers to reflect changing circumstances.

Request for comment – the views of stakeholders are encouraged on:

- what matters should be addressed in the proposed guidelines for interpretation of short run marginal cost bidding obligations under the Wholesale Electricity Market Rules;
- the types of costs that should be permitted for inclusion in prices offered into the STEM and the new real-time energy market;
- what matters specific to generators with larger portfolios need to be considered; and
- how and whether the input assumptions should vary in respect of offers made into the two energy markets.

6.3 Ancillary service markets

The Wholesale Electricity Market Rules also contain provisions to prevent the abuse of market power in the LFAS market. Synergy, due to its dominant position in the market, is required to act as the default provider of the service. Additionally, clause 7B.2.15 of the Wholesale Electricity Market Rules places a restriction on LFAS submission prices similar those applied in the energy markets:

> "A Market Participant must not, for any Trading Interval, offer prices within its LFAS Submission in excess of the Market Participant's reasonable expectation of the incremental change in short run marginal cost incurred by the LFAS Facility providing LFAS when such behaviour relates to market power."

As stated earlier, the Electricity Market Review proposes that Synergy remain the default provider of ancillary services in the Wholesale Electricity Market. In addition, the Electricity Market Review proposes that offer prices in the new ancillary service markets be restricted where a participant holds market power.

Further work will be needed during the implementation phase to develop the details of the pricing controls for the new ancillary service markets. This will include determination of:

- what price caps should apply in the ancillary service markets, for both participant offers and final prices[112]; and
- what costs a participant with market power should be able to include in its ancillary service offers.

It is expected that the proposed guidelines for the interpretation of the short run marginal cost bidding obligations would also cover any corresponding bidding obligations for the ancillary service markets.

[112] It is possible for ancillary service prices to exceed offer prices as the final prices are calculated through the co-optimisation process and can include the cost of backing off generating units and producing energy from more expensive units.

7. Assessment against design objectives

This chapter summarises how the proposed reforms would contribute to the objectives of the Electricity Market Review. 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.

7.1 Reducing production costs

The cornerstone of the proposed market design is the use of the Australian Energy Market Operator's NEMDE system. NEMDE is an advanced market clearing engine that is able to account for network and other constraints within the automated dispatch process. This delivers rapid, least-cost dispatch of energy and ancillary services without compromising power system security.

The use of NEMDE provides opportunities to increase efficiency and reduce costs that cannot be realised with existing systems and processes. For example:

- automating the management of network constraints allows network limits to be set more dynamically and less conservatively than at present, maximising the use of scarce network resources and avoiding unnecessary out-of-merit dispatch;
- the speed with which NEMDE can respond to changing system conditions and its ability to co-optimise the dispatch of energy and ancillary services would allow the removal of several material inefficiencies caused by long gate closure periods and the misalignment of gate closure times; and
- the availability of more timely and reliable information (such as more accurate dispatch forecasts that factor in the effect of network constraints), combined with later gate closure and shorter dispatch cycles, would allow market participants to make much more efficient unit commitment and bidding decisions, encourage greater participation and reduce the need to include risk premiums in market offers.

Further cost reductions would be expected over time as a consequence of increased market transparency. The new market arrangements – including, but not limited to, NEMDE-based dispatch, well-defined ancillary service markets and facility-based bidding for all participants – would impose a level of rigour and transparency on real-time market operations that does not exist today. The reforms would remove numerous cross-subsidies[113] and provide far greater clarity of where and how costs are being incurred.

[113] For example in relation to ancillary service costs, loss residues and the costs of managing the dispatch of the Synergy's generation portfolio.

It is extremely difficult to reduce market costs that cannot be accurately identified or measured. Greater transparency of these costs would both encourage and support their better management – for example through more accurate causer-pays incentives, increasing opportunities for competition, fine tuning of ancillary service requirements or more efficient management of the network.

The adoption of a NEMDE-based solution is also expected to provide substantial savings over time in market operation costs. The proposed design would allow the Australian Energy Market Operator to leverage its existing systems, processes and expertise, providing economies of scale and enabling access to sophisticated software and processes that might be unaffordable for the Wholesale Electricity Market in isolation. Closer alignment with the National Electricity Market would also give the Wholesale Electricity Market opportunities to benefit from future national initiatives to improve efficiency and reduce costs.

7.2 Reducing Government exposure to market risk

The achievement of this objective depends on how well the private sector is encouraged to invest in generation in the Wholesale Electricity Market. The proposed reforms support the objective by removing perceived investment risks and providing additional options for participation in the market.

The Wholesale Electricity Market is very unusual for a liberalised energy market in that the dispatch arrangements for the dominant, State Government-owned generator are quite different to those for other generators. The application of different rules for Synergy and the nature of the relationship between Synergy and the system operator (which manages the dispatch of the Synergy generation portfolio) may perturb potential investors, creating a perception of conflicts of interest and the risk of inequitable treatment. The arrangements for the Synergy portfolio also increase the complexity of the Wholesale Electricity Market Rules, which increases the level of perceived risk.

The proposed reforms would end most of the legacy arrangements for Synergy in the market. Although a few of Synergy’s market share-related obligations would be retained (such as the requirement to act as the Local Retailer and default provider of ancillary services), these remaining obligations are unlikely to concern potential investors.

Further, ending the special arrangements for the dispatch of Synergy’s generating units would remove unnecessary complexity from the Wholesale Electricity Market Rules and create a market design that would appear much more familiar and conventional to investors.[114]

7.3 Attracting stable private-sector market participants

The proposed reforms would be expected to promote private-sector investment in the Wholesale Electricity Market through improvements in the transparency and predictability of market outcomes.

[114] Particularly if those investors are active in the National Electricity Market.

Additionally, the close alignment of the proposed market design with the National Electricity Market would provide potential entrants that are already active in that market with opportunities to leverage their existing systems and processes, which may reduce their likely participation costs and encourage their entry to the market.

7.4 Summary

The proposed reforms provide a practical, fit-for-purpose solution that addresses the problems identified in this position paper and supports the objectives of the Electricity Market Review. The new market design would allow the Australian Energy Market Operator to leverage its systems, processes and expertise but would be tailored to account for the operation of the Reserve Capacity Mechanism and other Wholesale Electricity Market-specific needs. The design also aligns with and supports other proposed Electricity Market Review reforms in the areas of market competition and network regulation.

The proposed reforms would also leave the Wholesale Electricity Market well-positioned from a longer-term, strategic viewpoint. The new market design addresses the most urgent energy and ancillary service concerns, but excludes larger changes such as the introduction of full nodal pricing and its associated risk management tools. This approach avoids any major financial commitment down a path that diverges substantially from the National Electricity Market.

Electricity markets face an uncertain future, given the unpredictability of factors such as climate change policy, the development of renewable energy and storage technologies, and the growth of demand-side participation and small-scale distributed generation. The proposed reforms do not lock the Wholesale Electricity Market into a particular long-term development path. This means that future policy makers will have the freedom to monitor market developments and, in the longer term, select the best development option for Western Australia – whether this involves retention of the proposed arrangements, further enhancements to manage the growth of new technologies or a full transition to the National Electricity Market.

8. Implementation considerations

This chapter describes the foremost considerations for the implementation of reforms to the energy and ancillary service operations and processes of the Wholesale Electricity Market.

The Electricity Market Review is scheduled to provide an implementation proposal to the Minister for Energy by June 2016 for approval to implement reforms to the energy and ancillary service mechanisms. The market reforms are targeted to take effect on 1 July 2018 to align with the commencement of the constrained network access model.

The implementation phase will require close co-ordination of the:

- detailed design of operations and processes;
- drafting of amendments to the Wholesale Electricity Market Rules; and
- design and implementation of information technology system changes.

Detailed design of operations and processes

The proposed reforms outlined in this position paper are discussed at a relatively high level. The implementation phase will include a detailed design process to decide on the mechanisms and supporting arrangements required for reforms to registration, forecasting, pre-dispatch, dispatch and settlement processes.

The Electricity Market Review expects that one or more working groups will be convened during the implementation stage to assist with the detailed design process and provide feedback on rule drafting and information technology system development. The working group(s) would convene as soon as practicable after government approval to implement the reforms.

Drafting of amendments to the Wholesale Electricity Market Rules

The Electricity Market Review will lead the drafting of amendments to the Wholesale Electricity Market Rules, ensuring co-ordination with rule changes emanating from other projects within the review.

It is expected that the commencement of rule changes will be staggered.

- Some amendments may be able to progress in advance of 1 July 2018.
- Some transitional rules will be required to allow for commencement of the reforms on 1 July 2018 (for example, rules allowing for qualification to provide specific ancillary services).
- The bulk of the changes are expected to commence on 1 July 2018.

The decision to progress amendments ahead of the 1 July 2018 implementation date will be based on whether early implementation of the changes is feasible, would provide a material benefit and would have a negligible effect on the cost or duration of the overall implementation. Potential early amendments include:

- limited changes to participant and facility classes;
- changes to scheduling day processes, such as the removal of Resource Plans and the extension of the STEM submission windows;
- changes to the arrangements for determining loss factors and (if it proves to be justified) the reference node;
- development of guidelines for the interpretation of short run marginal cost bidding obligations; and
- amendments to the governance framework for system restart ancillary services.

In each case, the potential benefits of early implementation will need to be assessed against the additional costs that would be incurred and the risks of diverting scarce resources from the main implementation effort.

Request for comment – the views of stakeholders are encouraged on the feasibility, costs and benefits of early implementation of any of the proposed reforms.

It is expected that the Australian Energy Market Operator will be responsible for the development of market procedures.

Design and implementation of information technology system changes

The Australian Energy Market Operator will lead the development of information technology systems for market and dispatch operations.

In discussions with the Electricity Market Review, the Australian Energy Market Operator has acknowledged the need for a lengthy period of market trials to allow for testing of systems and interfaces and ensure a smooth transition to the new market arrangements. The Australian Energy Market Operator has indicated that it would aim to begin market trials in February 2018. It would liaise with market participants in advance of this date with the aim of market participants being ready to participate in the market trials as early as possible.

Co-ordination and stakeholder engagement

It is recognised that the development of changes to the Wholesale Electricity Market Rules and the development of market and dispatch systems will need to be tightly managed, and that adequate time will be needed for implementation of systems (both for the Australian Energy Market Operator and market participants), changes to market processes, and market trials before 1 July 2018. The Electricity Market Review will work closely with the Australian Energy Market Operator to ensure co-ordination between rule drafting and market system development processes.

The working group will not be able to accommodate all market participants, so broader industry workshops will be required to provide market participants with a global view of the reforms as they progress and information to assist their preparations for the new market arrangements.

Implementation costs

The development and implementation of new market and dispatch systems by the Australian Energy Market Operator is expected to be the largest single cost that directly results from the reforms proposed in this position paper. As discussed in Chapter 3, the implementation of these changes is essential in order to ensure system security and deliver efficiency benefits.

The Electricity Market Review has requested estimates of development and implementation costs from the Australian Energy Market Operator. It has committed to provide these estimates by the end of March 2016, in time to inform the implementation proposal.

The Electricity Market Review also seeks market participant input on the anticipated costs that must be incurred by market participants as a result of the proposed changes. It is expected that the magnitude of costs will vary depending on the circumstances of each individual market participant – some participants will only need to make minor adjustments to their current practices, while the proposed reforms will require substantial change for other participants.

Request for comment – submissions are encouraged that detail the costs that must be incurred by market participants as a result of the proposed changes.

9. Consultation

9.1 Initial consultation

This position paper has been informed by two rounds of targeted stakeholder consultation with market participants and other stakeholders.

Representatives from the Project Management Office held an initial round of stakeholder meetings during August 2015. The meetings were also attended by the economic consultants[115] supporting the project. The purpose of these meetings was to explore practicalities and inform the development of design proposals. A further round of consultation was held in December 2015 to refine the design proposal.

Stakeholders provided strong support for the aims of improving market transparency, accountability and efficiency in the provision of energy and ancillary service markets in the Wholesale Electricity Market.

Stakeholders generally supported the core design feature of moving to a security-constrained co-optimised dispatch of energy and ancillary services, with harmonised arrangements for market participants. It was generally recognised that this reform is essential as network constraints become more frequent – particularly with the adoption of a constrained network access model. Stakeholders generally acknowledged that the market and dispatch systems currently used in the South West Interconnected System do not have the required capability to support security-constrained dispatch so must be replaced, and that greater automation in market and dispatch systems could deliver market efficiencies.

The majority of stakeholders supported shorter gate closure and dispatch cycles for energy and ancillary service markets[116] based on the principle (and experience elsewhere) that more up-to-date and granular information would provide greater flexibility to market participants and promote more efficient dispatch outcomes.

The majority of stakeholders also expressed support for ex-ante price determination, retention of a single reference node and reference price, and retention of constrained-on compensation. A few stakeholders commented that some design aspects (for example changes to the reference node) may affect their contractual arrangements and may invoke change of law reviews.

Stakeholders agreed that there was a need for greater clarity around market power mitigation requirements, with some supporting more flexible arrangements around short-run marginal cost-based bidding restrictions. Views differed regarding the role of the STEM, with the smaller market participants generally indicating a stronger reliance on the STEM as a risk mitigation option.

[115] Oakley Greenwood/The Lantau Group were engaged by the Public Utilities Office to inform an assessment and development of reform proposals based on economic principles and international best practice.

[116] One market participant supported shorter gate closure, but not a shorter dispatch cycle due to problems in the National Electricity Market regarding alignment between dispatch and settlement pricing.

Generally, stakeholders expressed the view that implementation should be as cost-effective as possible, with some stakeholders suggesting that alignment with the National Electricity Market arrangements should be to the maximum extent practicable.[117] However, some stakeholders suggested that implementation of new market arrangements by 1 July 2018 would be challenging, even with close alignment with the National Electricity Market.

9.2 Invitation for written submissions

Respondents are invited to comment on the proposed reforms to the energy and ancillary service markets as outlined in this position paper.

Submissions need not be limited to those items identified for comment throughout this paper.

Submissions are due by 27 April 2016 and should be sent to:
electricitymarketreview@finance.wa.gov.au

It is requested that submissions have the following email subject line format:

- "Response to Position Paper: Design Recommendations for the Wholesale Energy and Ancillary Service Markets – [Name of the submitting company or individual]".

Publication of submissions

Unless you request otherwise, submissions will be publicly available at www.finance.wa.gov.au/publicutilitiesoffice.

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

Note that under Western Australian law (the *Freedom of Information Act 1992*), requests may be made for confidential submissions to be made available. Requests are determined in accordance with the provisions of that Act.

9.3 Next steps

The Electricity Market Review will take written submissions into account in the preparation of the implementation proposal, which will be provided to government by June 2016.

In the meantime, targeted stakeholder engagement is being progressed to further assess the implications of the proposed design. This is to include dialogue with the Australian Energy Market Operator and relevant stakeholders on implications for system operations and specific considerations such as facility registration.

As indicated in Chapter 8, it is envisaged that one or more stakeholder working groups will be established during the implementation phase to assist with the detailed market design.

[117] Stakeholders indicated that differences should be allowed where there is a compelling case (such as retaining dispatch on a "sent-out" basis as this better supports the Reserve Capacity Mechanism.

10. Disclaimer