Government of **Western Australia**
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Final Report: 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 generating unit. Market designs may require self-commitment (where the operator of a generating unit is responsible for the decision to start) or may operate with central commitment (where the system operator decides when to start a generating unit).
Constrained network access model	A model for the provision of access to an electricity network in 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.
Contingency lower service	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 load rejection reserve in the Wholesale Electricity Market.)
Contingency raise service	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 currently known as spinning reserve in the Wholesale Electricity Market.)
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.

Term	Definition
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.
Financially responsible market participant	The registered participant that is responsible for the purchase and sale of energy at a connection point with the transmission or distribution network, and is paid by (or pays) the Australian Energy Market Operator for these transactions.
First-tier load	A load connected to the distribution system that is supplied by the Local Retailer
Gate closure	The deadline for changes to generator offers into a market for a given dispatch interval.
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.)
Local Retailer	The retailer that is responsible for supplying any franchise loads in its designated local area, and for all energy flows into or out of its local area that are not allocated to other market participants.
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.

Term	Definition
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.
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.
Settlement by difference	The wholesale settlement model used in the National Electricity Market to manage the energy settlement of non-interval metered loads connected to a distribution system. 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.
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.
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

Major reform of the energy and ancillary service mechanisms in the Wholesale Electricity Market is essential to address material inefficiencies in the provision of these services and to ensure the ongoing management of system security.

The current market design enshrines hidden inefficiencies and cross-subsidies, which are estimated to be costing consumers tens of millions of dollars per year. In the absence of reform, it is likely that these costs will escalate and potentially form barriers to competition and investment. Transparency must be increased, to allow costs to be clearly identified so that steps can be taken to reduce them, reduce risks for market participants and improve competitive outcomes.

Existing market systems and processes must change as they will become unworkable as the frequency of network constraints increases in the coming years. These systems and processes have been designed on the basis that network congestion occurs rarely and only for short durations, with manual intervention required to manage network congestion when it occurs. However, with Western Power currently processing many connection applications for new generators, network congestion will only increase into the future and will be unable to be managed by the existing manual processes. Unless reform is instituted, the existing processes to manage constraints will represent a material barrier to new investment in the Western Australia electricity sector.

In addition, the adoption of the constrained network access model within the national framework for network regulation requires changes to the energy market design to support legal compliance with, and deliver the benefits of, the new network connection and access framework. Consequently, the finalised reforms to the energy and ancillary service operations and processes as outlined in this report are required to take effect on 1 July 2018, being the date upon which the National Electricity Rules in respect of network regulation are expected to come into force.

The package of reforms for the wholesale energy and ancillary service markets described in this report is centred on the adoption of a security-constrained market design, which will allow for the efficient, transparent and least-cost dispatch of generators while maintaining the security of the system – even as network congestion increases. This will require facility bidding for all market participants and co-optimisation of energy and ancillary service markets, each of which will enable efficiency gains to be realised. To complement these elements, a later gate closure and shorter dispatch cycle will also deliver considerable efficiency benefits and lower costs for consumers.

To support this reform package, the Electricity Market Review has initiated a broad review of market power mitigation measures for the energy and ancillary service markets and will publish a separate paper on this matter during the second half of 2016 for stakeholder consultation. This review will include consideration of the role of the Short Term Energy Market.

Market and dispatch systems used in the National Electricity Market, including the National Electricity Market Dispatch Engine (NEMDE), will be used by the Australian Energy Market Operator to implement the reforms. These systems have the capability to deliver the core reforms and represent a relatively simple, low-cost and low-risk implementation option. Leveraging this existing technology, which is already in operation and compliant with the National Electricity Rules, will allow the Wholesale Electricity Market to benefit from substantially lower implementation costs and risks, and lower ongoing market administration costs.

The estimated cost for the Australian Energy Market Operator to develop and implement new market and dispatch systems and to also prepare market procedures is expected to be between $25.3 million and $33.6 million.[1] This is relatively inexpensive compared with the costs of implementing alternative market and dispatch systems, which would be expected to be at least double the cost.

Quantifiable efficiency benefits and avoided costs associated with the reform package described in this report are estimated to be between $190 million and $375 million in present value terms.[2] These benefits represent an estimate of the direct benefits that are expected to arise from the reforms. These do not reflect the potential for much greater indirect benefits that will accrue to the wider Western Australian economy that will occur as a result of state benefiting from a more dynamic, transparent and efficient electricity sector.

The benefits that will arise from the reforms to the Wholesale Electricity Market will far exceed total implementation costs of the reforms, estimated at between $60 million and $100 million across all market participants.

The reform package provides a practical, fit-for-purpose solution that addresses the deficiencies in existing market systems and processes and supports the objectives of the Electricity Market Review. The reforms will lower costs, increase market transparency, improve competition between generators and improve investment signals. They will also align the Wholesale Electricity Market with common practice in competitive electricity markets, particularly the National Electricity Market.

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 in particular network regulation reforms that require the operationalisation of a constrained network access model that necessitates the adoption of a new security constrained dispatch engine.

The reforms will 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.

1 This figure includes costs for systems to support power system operation. The Electricity Market Review observes that some or all of these costs would be incurred even in the absence of reform to the wholesale energy and ancillary service markets, as a result of the transfer of System Management from Western Power to the Australian Energy Market Operator.

2 The present values have been calculated using a discount rate of eight per cent over 20 years. 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.

The proposed reforms do not lock the Wholesale Electricity Market into a particular long-term development path, allowing 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.

This report outlines the need for reform of the energy and ancillary service markets, details the elements of the reform package and expected benefits, describes the implementation process for the reforms and considers matters raised in stakeholder submissions.

The reforms outlined in this report are discussed at a relatively high level. The detailed design process will be supported by an industry working group, convened by the Electricity Market Review, to provide input on the mechanisms and supporting arrangements required for reforms to registration, forecasting, pre-dispatch, dispatch and settlement processes.

1. Introduction

This report describes a set of 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.

On 14 March 2016, the Electricity Market Review published a Position Paper seeking stakeholder feedback on proposed changes to the design and operation of the Western Australian Wholesale Electricity Market.[3] 15 submissions were received on the proposed reforms during the consultation period, which ended on 27 April 2016.[4] Matters raised in submissions have informed refinements to the reform package, as described in this report.

The purpose of this report is to provide stakeholders with a summary of the final proposal of the Electricity Market Review in respect of reforms to the energy and ancillary service markets in the South West Interconnected System. Specifically, this report includes:

- an outline of the rationale and high-level design for the reformed energy and ancillary service markets;
- a summary of the benefits of the reforms;
- discussion of matters raised in stakeholder submissions and consequent modifications made to the reforms proposed in the Position Paper; and
- information regarding the implementation of the reform package.

[3] Public Utilities Office, *Position Paper: Design Recommendations for Wholesale Energy and Ancillary Service Market Reforms*, 14 March 2016.

[4] Submissions are available at: http://www.finance.wa.gov.au/cms/Public_Utilities_Office/Electricity_Market_Review/Wholesale_Electricity_Market_Improvements.aspx

2. The need for reform

Reforms to the energy and ancillary service 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 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.

2.1 Opportunities for efficiency improvements

The current market design enshrines hidden inefficiencies and cross-subsidies, which are estimated to be costing consumers tens of millions of dollars per year. In the absence of reform, it is likely that these costs will escalate and potentially form barriers to competition and investment.

The design of the energy and ancillary service markets must be changed to provide a level of transparency that allows costs to be clearly identified so that steps can be taken to reduce them. Costs are not transparent due to the manner in which the Synergy portfolio is currently dispatched by System Management, the lack of clear boundaries between energy dispatch and the various frequency control ancillary services, and the manual management of network congestion when it arises (discussed further in section 2.2). The lack of transparency makes it difficult for generators (especially Synergy as the major provider of ancillary services) to price their dispatch offers and impossible to ascertain the purposes for which each generating unit is dispatched.

Further, the inability to precisely measure ancillary services appears to contribute to an overly conservative procurement of these services, while making it impossible to identify specific actions to reduce costs. This conservatism is demonstrated by recent frequency performance for the South West Interconnected System, which exceeds the standard prescribed in Western Power's Technical Rules by two orders of magnitude.[5]

Additional inefficiencies result from the early gate closure, relatively long dispatch cycle and lack of co-optimisation of energy and ancillary services in the current market design. These inefficiencies directly increase costs for consumers.

- The early gate closure and long dispatch cycle (relative to other competitive electricity markets) reduce the accuracy of demand forecasts, restrict the ability of generators to adapt to changes in system conditions and increase the burden on costly ancillary services.

[5] 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.

- The lack of co-optimisation of energy and ancillary services increases the risk of providing both services, meaning that participants are likely to include a material risk margin in these offers or opt out of participating in the load following market.

Reforms to the energy and ancillary service markets could unlock substantial cost savings in energy dispatch and ancillary service provision. This could be achieved through changes that increase transparency of costs and market processes, increase opportunities for competition, reduce forecast inaccuracies and provide greater flexibility for generators to adapt to changes in system conditions.

2.2 Management of system security and network constraints

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. These systems and processes must change as they will become unworkable as the frequency of network constraints increases in the coming years, particularly in areas that are most prospective for investment in renewables generation.

The physical limitations of the transmission network are not accounted for in current 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, which is operationally burdensome and increases the likelihood of errors or inefficient dispatch. The slow speed of such manual processes hinders efficiency improvements to the existing market design, such as later gate closure, a shorter dispatch cycle or co-optimisation of energy and ancillary services.

Forecast dispatch plans can be unreliable as they ignore the effects of congestion, discouraging active competition in the real-time market, while the compensation mechanism for out-of-merit dispatch 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.

Western Power is currently processing a large group of 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 therefore be expected to result in further material increases in the frequency of binding constraints.

Western Power and System Management have indicated that new systems and processes for system operation would be needed to support the entry of new generators and manage network congestion. In the absence of the reforms being pursued by the Electricity Market Review (including changes to network regulation), custom-built dispatch tools would need to be developed to cope with new generator connections.

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.

The current portfolio bidding approach for Synergy is incompatible with an automated, 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.[6]

2.3 Alignment with other Electricity Market Review reforms

Reforms to the energy and ancillary service markets are also required to ensure consistency with, and achieve benefits from, other reforms being implemented by the Electricity Market Review.

- The Electricity Market Review is adopting the national framework for network regulation, which incorporates a constrained network access model, to take effect on 1 July 2018. It is imperative that energy market arrangements operate consistently with the network connection and access framework in order to support legal compliance with, and deliver the benefits of, the network regulation reforms. This requires the implementation of a security-constrained market design.
- The *Electricity Industry (Metering) Code 2012* currently requires that all loads in the South West Interconnected System without interval metering are to be served by Synergy and be prohibited from transferring to another retailer.[7] For simplicity of wholesale market settlement, these loads are then treated as a single, Synergy-owned Notional Wholesale Meter. It is expected that the transfer of at least some non-interval metered loads will be permitted on or shortly after 1 July 2018. 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.
- From 1 July 2018, the Australian Energy Market Operator will have responsibility for wholesale market operation, retail market operation and system operation for the South West Interconnected System. This will closely align with the functions that it undertakes for the National Electricity Market. The systems that the Australian Energy Market Operator uses to perform these functions in the National Electricity Market are strongly interconnected. Consequently, leveraging the Australian Energy Market Operator's technology and National Electricity Market processes to the maximum extent practicable (where these meet the needs and characteristics of the South West Interconnected System) would reduce the cost and risk of implementation, and create opportunities for synergies that could reduce ongoing administration, operational and system costs.

In each of the cases described above and in the previous sections, benefits can be achieved through alignment with systems and processes used by the Australian Energy Market Operator in the National Electricity Market, which are already in operation and compliant with the National Electricity Rules. Leveraging these systems and processes removes the need for the development of bespoke systems that would have substantially greater implementation costs and risks, and would increase ongoing market administration costs.

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6 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.

7 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

3. Final reform package to be implemented in the South West Interconnected System

The package of reforms for the wholesale energy and ancillary service markets is centred on the following core features, which are common to many 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.

A later gate closure and shorter dispatch cycle are complementary reforms that are expected to deliver considerable efficiency benefits and lower costs for consumers.

Market and dispatch systems used in the National Electricity Market, including the National Electricity Market Dispatch Engine (NEMDE), will be used in the implementation of the reforms. These systems provide the capability to deliver the core reforms and represent a relatively simple, low-cost and low-risk implementation option.

Table 3.1 lists the elements of the reform package. Further information on these elements is provided in chapter 4, including responses to matters raised by stakeholders in submissions to the Position Paper.

Table 3.1: Design elements of final reform package

Reform area	Final reforms
Spot market and dispatch	• Adoption of NEMDE to implement: – Security-constrained dispatch using a hub-and-spoke network (constraint) representation – Facility bidding for all market participants – Introduction of competitive frequency control ancillary service markets based on those in the National Electricity Market, with Synergy required to offer due to its dominant market position – Co-optimisation of energy and ancillary service markets – Common gate closure for all market participants, to occur between 5 and 30 minutes prior to the start of the trading interval – Five-minute dispatch cycle – Single reference node with a single spot price for energy and a single spot price for each frequency control ancillary service – Reference node to be shifted from Muja to a load centre in the Perth metropolitan area – Ex-ante prices determined for each 5-minute dispatch interval and averaged to 30-minute trading intervals for settlement • Self-commitment for all generators • Dispatch on a ‘sent-out’ basis by default, with special consideration for specific sites • Retention of generator outage scheduling and approval processes

Reform area	Final reforms
Registration	General alignment with the facility and participant classes and terminology used in the National Electricity Market, with similar alignment of registration processes, while taking into account any specific requirements of the Wholesale Electricity Market. • Specific proposals for generators: – 10 MW threshold for exemption from registration – Non-intermittent generating units to only be eligible for Capacity Credits if classified as scheduled generating units – Intermittent generating units to be eligible for Capacity Credits regardless of whether classified as semi-scheduled or non-scheduled – Only the financially responsible market participant to be eligible for Capacity Credits for a generating unit – Financially responsible market participant not required to be the holder of the connection agreement with the network service provider – Small generation aggregator classification not to be included at this time • Specific proposals for customers: – Single local area to be defined for the South West Interconnected System with Synergy as the Local Retailer – Retention of Demand Side Programmes and Associated Loads – Allow loads to provide ancillary services, participate as scheduled loads and participate in Demand Side Programmes (subject to meeting technical criteria) – Continue to allow a participant other than the financially responsible market participant to register an ancillary service load or associate a load with a Demand Side Programme – Support aggregation of ancillary service loads • Accommodate (with some changes) existing Intermittent Load arrangements
Network losses	• Transmission loss factors to be determined annually by the Australian Energy Market Operator • Distribution loss factors to be determined annually by the distribution network service provider(s) • The respective parties to be responsible for publishing the methods for determining loss factors • Retention of the current ability for participants to request a reassessment of loss factors, subject to being liable for the cost of the audit if no material error is identified • Requests for reassessment of loss factors to be submitted to the Economic Regulation Authority (currently such requests are submitted to the Australian Energy Market Operator) • No formal approval process for distribution loss factors, given the retention of the reassessment process

Reform area	Final reforms
Settlement	• Align settlement timeframes with weekly settlement processes in the National Electricity Market • Adoption of 'settlement by difference' approach as used in the National Electricity Market • Hybrid approach to allocation of transmission loss residues, to be used to offset constrained-on compensation payments in the first instance with the remainder (or any negative loss residues) allocated to the transmission network service provider • Retain constrained-on compensation (with modified calculation) • Remove constrained-off compensation • Ancillary service cost allocation: – Adopt 'causer pays' method for allocating regulation costs – Implement 'full runway' method for allocating contingency raise costs – Continue to allocate costs of contingency lower to customers based on consumption share – Continue to allocate system restart ancillary service costs to customers
Non-market ancillary services	• Transmission network service provider to be responsible for procuring Network Support and Control Ancillary Services (NSCAS), with costs recovered through its regulated revenue process • No backstop power for the Australian Energy Market Operator to procure NSCAS • Existing Dispatch Support Service contract between Synergy and System Management to be terminated; Western Power, the Australian Energy Market Operator and the Economic Regulation Authority to identify any services that should be provided in future under a network support agreement • Australian Energy Market Operator to be required to gain approval from the Economic Regulation Authority prior to entering into a system restart ancillary service contract
Market power mitigation and forward market	• Electricity Market Review to undertake a broader review of market power mitigation measures in the energy and ancillary service markets, including consideration of bidding restrictions, price caps and the Short Term Energy Market (STEM)

The package of reforms in Table 3.1 has been developed at a relatively high level. As discussed in chapter 6, 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.

4. Response to submissions

The Position Paper described the proposed reforms to the energy and ancillary service markets in the South West Interconnected System. The paper also invited stakeholder submissions in respect of the proposed reforms, including requests for feedback on several specific matters.

The majority of the submissions received were either broadly supportive of the proposed reforms or were limited to matters of commercial relevance to the submitting party. Two submissions, from Synergy and Perth Energy, expressed several concerns regarding the proposed reforms. The Electricity Market Review has held follow-up discussions with stakeholders where necessary to clarify matters raised in submissions.

This chapter provides a summary of the submissions received on the Position Paper and the changes made by the Electricity Market Review to the proposed reforms after consideration of those submissions. Sections 4.1 to 4.6 discuss the matters on which feedback was specifically sought in the Position Paper while section 4.7 discusses other matters raised by stakeholders. Submissions in respect of the cost and timing for implementation of the reforms are discussed in chapter 6.

4.1 Core reform components

Security-constrained market design, facility bidding for all generators, co-optimisation of energy and ancillary service markets and a shorter dispatch cycle

The submissions provided broad support for the core reform components, with only a few submitters qualifying their support.

The Electricity Market Review acknowledges concerns expressed in four submissions regarding the transition to a constrained network access model and constrained market design (including the proposed removal of constrained-off compensation payments).[8] The Electricity Market Review is investigating the transition of existing network access contracts and will undertake consultation with stakeholders during the second half of 2016. However, economically efficient, least-cost dispatch of generation is a fundamental objective of the reforms to the wholesale energy and ancillary service markets. Consequently, transitional measures that preserve preferential physical access for an existing generator are not preferred as this would materially undermine the efficient least-cost dispatch of generators.

Perth Energy's support for the core reform components was also conditional on the energy price limit being increased to around $10,000 per MWh from the current price caps of around $300 per MWh. Perth Energy suggested that the increase is required as a consequence of the recently announced reforms to the Reserve Capacity Mechanism, which it considers to have materially increased the risk of participation.[9] While the Electricity Market Review will be considering price caps within a broader review of market power mitigation options, it does not agree with the basis of Perth Energy's suggestion.

[8] See submissions by Alinta Energy, ERM Power, Perth Energy and Tesla Corporation.
[9] These reforms are described in the *Final Report: Reforms to the Reserve Capacity Mechanism*, available at http://www.finance.wa.gov.au/cms/Public_Utilities_Office/Electricity_Market_Review/Wholesale_Electricity_Market_Improvements.aspx.

- The reforms to the Reserve Capacity Mechanism will make it more responsive to market conditions. While these reforms will result in lower capacity prices when there is a substantial excess of capacity, they will allow capacity prices to rise higher than today as the capacity position tightens. This is the case both for the transitional changes to the administered Reserve Capacity Price formula and under a capacity auction.
- In a capacity plus energy market design, energy and capacity prices must work together to drive efficient levels of investment in generation capacity. The reforms to the Reserve Capacity Mechanism are intended to sharpen price signals to investors when there is an oversupply or undersupply of capacity in the market. Increasing the energy price caps would blunt this signal and defeat the purpose of the Reserve Capacity Mechanism reforms.

Synergy expressed conditional support for the proposed direction and the majority of the recommendations in the Position Paper, including broad support for facility bidding (though it welcomed further discussion on options that may exist for aggregation of co-located generating units for bidding and dispatch). Synergy's support was conditional on the receipt of funding for implementation and transition costs, and sufficient time to implement the required changes. The Electricity Market Review acknowledges that the implementation and transition costs for Synergy will be considerably greater than those of other market participants and will assist Synergy in its estimation of these costs. In respect of implementation timing, it is essential that the frameworks for network regulation and market dispatch are aligned, meaning that the market reforms will need to commence on 1 July 2018, the date from which the national framework for network regulation will be legislated to take effect.

Bluewaters Power observed that the proposed reforms appear reasonable and warranted, but was unable to confidently provide support for the reforms as the detailed design has yet to be developed, making it difficult for market participants to fully understand the effect on their operations. The Electricity Market Review acknowledges this concern and will be seeking market participant involvement during the detailed design process, as discussed in chapter 6.

Gate closure

The 10 stakeholders that submitted on this matter were all supportive of later gate closure, to occur no earlier than 30 minutes before the start of the trading interval. However, several of these submissions expressed reservations about the abolition of a formal gate closure period, highlighting the scale of the proposed reforms and (in some instances) raising concerns about problems observed in the National Electricity Market with rebidding occurring within the trading interval. Various preferences were expressed in relation to the gate closure timing, ranging from 5 to 30 minutes prior to the start of the trading interval.

Considering the reservations expressed by market participants about the abolition of a gate closure, the Electricity Market Review has decided that a formal gate closure will continue to apply in the Wholesale Electricity Market from 1 July 2018. The specific time (between 5 and 30 minutes prior to the start of the trading interval) will be determined during the implementation phase in consultation with market participants, along with the circumstances under which late rebidding should be permitted or required (for example to update unit availability after a forced outage). The same gate closure period will be used for all market participants and for both the energy and ancillary service markets.

Ex-ante pricing

Nine stakeholders submitted on this matter, with eight expressing support for a shift to ex-ante pricing. Synergy was the only submitter to oppose ex-ante pricing, suggesting that it places a downward bias on prices and undervalues plant availability and flexibility. However, Synergy's submission suggested that if ex-ante price determination was adopted, there should be the ability for ex-ante prices to be revised in the event of a manifest error.

The Electricity Market Review considers that any bias in ex-ante prices would be inconsequential in comparison with the benefits of reducing risk for generators and removing the need for constraint payments to compensate generators where ex-post prices are different from what was forecast at the time of dispatch. In addition, the Electricity Market Review observes that a mechanism exists in the National Electricity Rules, and is accommodated in the Australian Energy Market Operator's systems, to adjust ex-ante prices where a manifest error is detected.[10]

The Electricity Market Review has decided to align with the National Electricity Market's processes for ex-ante price determination.

4.2 Dispatch engine and network model

NEMDE-based implementation with single reference node

10 of the 11 submissions on this matter supported the proposal to implement the reforms using NEMDE, with a single reference node. Synergy, the only submitter to question the proposal, suggested that other constrained market models (such as that used in New Zealand) may deal with real-time network losses more effectively and that locational pricing should be considered further. Western Power also suggested that stronger locational pricing signals may be required in the future, but supported a NEMDE-based implementation as "a pragmatic balance between cost and complexity".

The Electricity Market Review acknowledges that a nodal market model can more accurately model network flows and losses than the hub-and-spoke model used in the National Electricity Market. However, the Electricity Market Review considers that the potential benefits of a nodal market model are unlikely to outweigh the material benefits of a NEMDE-based implementation in terms of simplicity, familiarity, cost, risk and speed of implementation.

Choice of reference node

Nine submissions discussed the potential change of 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). Five submissions supported a change of reference node to a major load centre.[11]

[10] See clause 3.9.2B of the National Electricity Rules.

[11] See submissions by the Australian Energy Market Operator, Western Power, Alinta Energy, the Economic Regulation Authority Secretariat and ERM Power (ERM Power also provided advice on criteria for selecting the location of the new node).

In particular, the Australian Energy Market Operator suggested that the placement of the reference node at a major load centre is an essential feature of a constrained market design. It explained that the location of a reference node at a generation centre (as it is today) can hinder the constraint of generation facilities at the reference node when required, create additional complexity for the management of system security and potentially distort the setting of the market price.

Three stakeholders indicated that they were unable to support a change of reference node in the absence of analysis to explain the commercial effects of the change.[12] Synergy was the only stakeholder to oppose a change of reference node, suggesting that there was inadequate justification for a change at this time and questioning the value of such a move if locational pricing may be required in the future.

Considering the balance of submissions and the technical and economic justifications provided by the Australian Energy Market Operator, the Electricity Market Review has decided that the reference node should be shifted to a network location in the Perth metropolitan region. The location will be determined early in the detailed design process, in conjunction with Western Power and the Australian Energy Market Operator.

The Electricity Market Review acknowledges advice from some stakeholders that a change of reference node will require amendments to some power purchase agreements. As other reforms taking effect on the same date are likely to necessitate amendments to these contracts (such as the adoption of a constrained network access model), the Electricity Market Review has decided that the change of reference node will take effect on 1 July 2018 to provide greater certainty for market participants and allow for the potential consolidation of amendments to contracts.

To assist market participants to understand the implications of a change of reference node, the Electricity Market Review will publish an information paper that outlines the effects on transmission loss factors and settlement.

Basis of dispatch

Five submissions provided general support for the proposal in the Position Paper, being for dispatch to occur on a 'sent-out' basis by default, with a pragmatic approach to accommodate the current mixture of facility configurations and dispatch arrangements in order to avoid imposing unnecessary costs.[13] Only one stakeholder (ERM Power) supported transitioning to dispatch based on as-generated quantities, suggesting that this would reduce the complexity of co-optimisation and provide more transparent outcomes.

The Electricity Market Review affirms the proposal in the Position Paper and is continuing its discussions with the Australian Energy Market Operator, Western Power and market participants in relation to the dispatch configuration for Intermittent Load facilities and some older power stations. These discussions will inform the configuration of dispatch systems and the drafting of changes to the Wholesale Electricity Market Rules.

[12] See submissions from Bluewaters Power, NewGen Power Kwinana and Perth Energy.

[13] Dispatch based on sent-out quantities (as the default) was supported by Bluewaters Power, NewGen Power Kwinana and the Economic Regulation Authority Secretariat. The support of the Australian Energy Market Operator was conditional upon it receiving sufficient access to behind-the-fence operational information for the maintenance of system security. Western Power also supported the proposal, but indicated that some of the existing Intermittent Load arrangements may present challenges for the development of network constraint equations.

4.3 Ancillary services

Design of frequency control ancillary service markets

Three stakeholders made specific comments in relation to the design of frequency control ancillary service markets.

Western Power suggested that there should be flexibility in the specification of frequency control ancillary service markets, since change in the electricity sector (such as the growing penetration of distributed generation) may lead to a requirement for new frequency control ancillary services. The Electricity Market Review will consult with the Australian Energy Market Operator about the details of the services to be defined, to ensure that they are fit for purpose in the South West Interconnected System. In discussions with the Electricity Market Review, the Australian Energy Market Operator has advised that preliminary work is occurring to increase its flexibility to define new frequency control ancillary services in the National Electricity Market. The Electricity Market Review will continue to monitor this work.

Synergy suggested that any requirement for it to be a default provider of frequency control ancillary services should terminate or be subject to review at a future date. The Electricity Market Review agrees that evidence of active competition in frequency control ancillary service markets may provide justification to remove the default provider requirement. The Electricity Market Review considers that the Economic Regulation Authority's annual review of the effectiveness of the Wholesale Electricity Market is the most suitable vehicle for such a review and intends that discussion of the effectiveness of the frequency control ancillary service markets will form part of updated requirements for this report.[14]

The Economic Regulation Authority Secretariat provided support for increased competition in ancillary services, but suggested that "short-term expectations of increased competition in the ancillary service market should be modest given Synergy's large market generation share". The Electricity Market Review acknowledges that it may take time for competition to increase, with some potential providers of frequency control ancillary services being likely to observe market outcomes before making commercial decisions about whether to participate. However, the Electricity Market Review expects that material long-term economic benefits will accrue by exposing these services to competition and removing cross-subsidies.

Allocation of frequency control ancillary service costs

The Electricity Market Review affirms the proposal to allocate the cost of contingency raise services using a 'full runway' allocation method. This cost allocation method provides marginal signals whereby the cost of the incremental unit of contingency raise reserve is allocated only to the generators that have created the need for it.[15]

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[14] This annual review is required under clause 2.16.11 of the Wholesale Electricity Market Rules, with requirements for the report listed in clauses 2.16.9, 2.16.10 and 2.16.12.

[15] This method is described in detail in Charles River Associates, *Review of Market Ancillary Services*, January 2004, which is available at http://www.neca.com.au/Files/A_Review_AS_CRA_Report_Jan2004.pdf. This report describes the link between generation output in a particular time interval and the share of cost that is borne. "[T]he largest unit faces the full cost of the [reserve] requirement which it imposes over and above the [reserve] requirements imposed by all other units. But the two largest units, collectively, share the cost of the [reserve] requirement which they collectively impose over and above the reserve requirements imposed by all other units. Then the three largest units, collectively, share the cost of the [service] requirement which they collectively impose over and above the [service] requirements imposed by all other units. And so on, until the signal faced by the smallest units is really quite dispersed." (Page 37)

The six stakeholders that submitted on this matter all supported the full runway method, although the Australian Energy Market Operator advised that this would require modification to its existing systems. The Electricity Market Review considers that that the increase in system implementation costs is outweighed by the economic efficiency benefits of allocation of costs on a ‘causer pays’ basis.

Three stakeholders submitted on the allocation of regulation (load following) service costs. The Economic Regulation Authority Secretariat supported the proposal to adopt the ‘causer pays’ cost allocation method used in the National Electricity Market, while Bluewaters Power and NewGen Power Kwinana did not support the proposal. Bluewaters Power agreed that the causer pays method had merit but questioned whether the market would derive sufficient benefit to warrant the additional complexity associated with this change, particularly given the expectation that a shorter dispatch cycle could reduce the costs of the regulation service. Bluewaters Power also suggested that such operational costs should be levied on the end-use customer and flagged challenges for generators to pass this cost through to customers.

The Electricity Market Review has decided to adopt the causer pays method for allocation of regulation costs. Generator actions can influence the regulation service requirement, so the causer pays method would provide participants with sharper incentives to limit their contribution to the overall regulation requirement, thus lowering costs for electricity consumers.

Approval and allocation of system restart ancillary service costs

Only four stakeholders submitted on this matter. ERM Power and Alinta Energy supported retention of the existing allocation of system restart costs to customers, while Synergy and Perth Energy supported allocation of costs to both generators and customers.

In explaining its preference to retain the existing allocation method, both Alinta Energy and ERM Power argued that customers are the main beneficiaries of the system restart service, which primarily exists to limit the economic loss to customers of supply interruptions. Each submission observed that the Value of Customer Reliability in the National Electricity Market far exceeds the market price cap and generator short-run marginal costs. In contrast, Perth Energy highlighted the benefit of alignment with the National Electricity Market arrangements and suggested that generators and customers are joint beneficiaries of the service.

An additional consideration, not raised in submissions, is that generators are unable to modify their operations to limit the service requirement. As generator actions do not affect the service requirement, the allocation of costs to generators would not lead to more efficient outcomes, but merely impose a cost burden that would ultimately need to be recovered from customers. In such instances, it is typically more efficient to allocate costs directly to customers.

Considering the justifications provided in submissions and the additional considerations stated above, the Electricity Market Review has decided that system restart costs in the Wholesale Electricity Market will continue to be allocated to customers according to their share of consumption.[16] The Australian Energy Market Operator has indicated to the Electricity Market Review that this is not expected to affect implementation costs.

The Economic Regulation Authority Secretariat was the only stakeholder to submit in respect of the governance arrangements for system restart ancillary service contracts, supporting the proposal that the Australian Energy Market Operator should be required to gain the approval of the Economic Regulation Authority prior to entering into a contract.

Procurement of Network Support and Control Ancillary Services (NSCAS)

Western Power was the only stakeholder to submit on this matter, suggesting that it may not be suitable for the transmission network service provider to fund NSCAS in all instances. Western Power suggested that a 'last resort' power should be provided to the Australian Energy Market Operator to procure NSCAS and recover costs from market customers. This would occur in situations where the transmission network service provider was unable to establish an NSCAS contract with a provider in the required timeframe or where the Australian Energy Regulator disagreed that an NSCAS was required and decided against including the associated cost in the allowable revenue.

The Electricity Market Review is investigating the role of the Australian Energy Market Operator in developing forecasts of network capacity and identifying 'NSCAS gaps', and will undertake consultation with stakeholders on this matter during the second half of 2016. In the event that the Australian Energy Market Operator is required to identify NSCAS gaps, this investigation will also consider the roles and responsibilities of the various parties (the Australian Energy Market Operator, Western Power and the Economic Regulation Authority) in either filling or not filling the identified gap.

However, the Electricity Market Review does not agree that the Australian Energy Market Operator should have a backstop power to procure NSCAS. In particular, it would be difficult to justify the procurement of an NSCAS by the Australian Energy Market Operator in a situation where the Australian Energy Regulator had determined that an NSCAS was not required.

4.4 Registration

Submissions included several comments on registration matters, not all of which are discussed in this report. No stakeholder raised major concerns with the proposal to adopt, as far as practicable, the participant and facility registration classes and associated terminology of the National Electricity Market.

The Electricity Market Review acknowledges that further detailed design work is required to finalise the participant and facility classes. This will need to occur early in the detailed design process as other design areas will be dependent upon the registration design. Further consultation with market participants will occur during this process.

[16] This is contrary to the Position Paper, which proposed allocation to both generators and customers for consistency with the National Electricity Market.

No stakeholder made a case for modification of the 10 MW threshold for registration of generating units, whereby 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.[17] Consequently, the Electricity Market Review has decided that the 10 MW threshold will remain prescribed in the Wholesale Electricity Market Rules, below which a generator will not be required to register in the market or seek a registration exemption from the Australian Energy Market Operator. The same threshold will apply in relation to participation in the central dispatch process. The Australian Energy Market Operator will be responsible for deciding requests for exemption from registration in respect of a generating unit larger than 10 MW.

Blair Fox raised concern about the risk of the Australian Energy Market Operator requiring small generators to implement costly communication systems. The Electricity Market Review confirms that it is not intended to force small generators with a rated capacity less than 10 MW to participate in central dispatch and impose onerous communication and control system requirements.

TransAlta supported the retention of the current Intermittent Load arrangements in the Wholesale Electricity Market Rules, which seek to accommodate sites at which large load and generating units are located behind a single connection point. TransAlta expressed concerns about the potential effect of any new facility aggregation provisions on Intermittent Loads and potential changes to its current exemption from registration as a network operator. The Electricity Market Review is continuing to work with stakeholders (specifically the Australian Energy Market Operator, Western Power and affected market participants) to determine the most pragmatic method to incorporate Intermittent Load sites into the new market design.

4.5 Settlement

Settlement timelines

Eight of the ten submissions on this matter expressed a preference for wholesale market settlement to occur earlier than the current monthly Non-STEM settlement arrangements.[18] Of these, three stakeholders explicitly supported alignment with the weekly settlement timelines of the National Electricity Market.[19] This included Western Power, confirming its intention to be compliant with the meter data delivery requirements needed to support this timeline. Another two stakeholders supported amalgamation of the current STEM and Non-STEM settlements into a single settlement process but were ambivalent to the timing of this process.[20] One stakeholder (Community Electricity) discussed the benefits of shorter settlement timeframes in reducing the quantity of prudential support required and highlighted deficiencies in the current calculation of prudential requirements for the disparate STEM and Non-STEM settlements.

[17] Western Power supported retention of the current 10 MW threshold and suggested that the technical requirements of Chapter 5 would be a substantial impost on smaller generators. Synergy supported the removal of automatic exemption thresholds, with AEMO to be responsible for determining any exemption criteria, but did not explain its position.

[18] The Non-STEM settlement covers all transactions other than bilateral trade quantities and STEM purchases and sales. It includes transactions in respect of the Balancing Market, the Reserve Capacity Mechanism, ancillary services and market fees.

[19] See submissions from the Australian Energy Market Operator, ERM Power and Western Power.

[20] See submissions from Bluewaters Power and NewGen Power Kwinana.

Alinta Energy and Perth Energy both expressed a preference for settlement timeframes to be shortened, but advocated retention of monthly Non-STEM settlement. Alinta Energy suggested that a transition to weekly settlement be considered at a later date within the market evolution plan. Perth Energy, Synergy and Blair Fox opposed a move to weekly Non-STEM settlements, expressing concerns about increased working capital requirements and higher administration costs.

In subsequent discussions with the Electricity Market Review, the Australian Energy Market Operator has advised that there would be material implementation and operational costs to adapt its settlement systems to accommodate the separate settlement cycles currently used in the Wholesale Electricity Market. The Electricity Market Review considers that the administrative burden associated with weekly settlement is not improper for participants in the Wholesale Electricity Market, and that the benefit of reduced prudential support requirements should balance any detrimental effects in respect of additional working capital requirements.

Based on these factors, the apparent level of support for faster settlement and Western Power's intentions to comply with the meter data delivery requirements of the National Electricity Market, the Electricity Market Review has decided that wholesale market settlement should be moved to a single weekly cycle from 1 July 2018.

Settlement by difference and allocation of loss residues

Only four submissions considered the allocation of settlement residues (loss residues) that arise due to the way in which static marginal transmission loss factors are used in settlement of the wholesale market.[21] 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.

Alinta Energy supported the hybrid option presented in the Position Paper, in which loss residues are first used to offset constrained-on compensation with the remainder allocated to the transmission network service provider. Alinta Energy indicated that both loss residues and constrained-on payments are "settlement risks that are outside of retailers' control and cannot be cost-effectively hedged". Alinta Energy also considered that the adoption of the 'settlement by difference' approach, used for wholesale market settlement in the National Electricity Market, should take effect from 1 July 2018 to allow loads without interval meters to transfer to another retailer and to limit implementation costs. Alinta Energy considered that a 'global settlement' model would reduce distortions in wholesale settlement[22] but would be unjustifiably expensive to implement.

Western Power suggested that loss residues should be allocated symmetrically (i.e. identical methods for allocation of positive and negative residues). In a subsequent discussion with the Electricity Market Review, Western Power advised that it did not hold a strong view on this matter, but suggested it may be preferable to keep loss residues distinct from constrained-on compensation as they arise from different causes. Perth Energy similarly preferred to allocate all loss residues to the network service provider for simplicity.

[21] The loss residues arise because actual transmission losses differ from the static marginal transmission loss factors that are applied for the purpose of wholesale settlement.

[22] Alinta Energy explains that distortions arise mainly due to "data estimation, net system load profiling and the use of static average distribution loss factors.

Synergy's submission was unclear on how loss residues should be allocated, but supported a global settlement model (as opposed to the settlement by difference approach used in the National Electricity Market) and suggested that the change should coincide with the implementation of full retail contestability. A global settlement model would not utilise the local area and Local Retailer concepts that form part of the settlement by difference approach.

The Electricity Market Review observes that the existing settlement model using the Notional Wholesale Meter must be replaced due to the adoption of the Australian Energy Market Operator's dispatch and wholesale settlement systems. In a subsequent discussion with the Electricity Market Review, Synergy did not dispute the potential costs of requiring the Australian Energy Market Operator to modify its settlement systems to retain the current Notional Wholesale Meter settlement model.

In relation to transmission loss residues, the Electricity Market Review agrees with the reasons outlined by Alinta Energy in support of the hybrid option for loss residue allocation presented in the Position Paper and has decided to implement this option.

The Electricity Market Review acknowledges that a global settlement model may allow for more equitable allocation of costs to all retailers and considers that there may be merit in enabling the gathering of data to quantify any inaccuracies that arise. However, the Electricity Market Review agrees with Alinta Energy's submission that the expense of implementing a global settlement model is not warranted at this time. The Electricity Market Review considers that this position should be reviewed if the National Electricity Market was to adopt a global settlement model in the future, due to the potential for implementation cost and risk to be shared with the National Electricity Market.

4.6 Market power mitigation and STEM

Submissions on the value of short run marginal cost-based bidding obligations and the need for clarity on these obligations varied widely.

The Economic Regulation Authority Secretariat strongly supported the proposals in the Position Paper for the retention of restrictions on price offers and the development of practical guidelines for the formation of offers. This submission also referenced other recent work by the Economic Regulation Authority discussing the inability of national competition law[23] to curb the transient exercise of market power. Community Electricity and Perth Energy also supported the development of guidelines for the construction of short run marginal cost-based offers, though the latter suggested that offer restrictions could be relaxed if Synergy's generation portfolio was split into competing business units.

In contrast, Synergy suggested that the existing short run marginal cost-based bidding obligations are too strong and should be subject to a comprehensive review, preferring deference to national competition law. Synergy also raised concerns about the combined effects of facility bidding and the market power mitigation mechanisms. Synergy suggested that, if cost-based bidding obligations were to be retained, a brief statement of principles would be warranted to provide clarity on what costs could be included in bids. Alinta Energy also suggested that a review of the need for short run marginal cost bidding obligations is required and did not support the development of guidelines in the interim.

[23] Principally the *Competition and Consumer Act 2010*.

The Electricity Market Review has decided to undertake a broader review of market power mitigation measures for the energy and ancillary service markets and will publish a separate paper on this matter during the second half of 2016 for stakeholder consultation. To support this work, the project team will meet with Synergy to provide it with further opportunity to articulate specific concerns with the combination of facility bidding and cost-based bidding obligations.

The compulsory nature of the current STEM and the associated cost-based bidding obligations promote liquidity and mitigate market power, so the Electricity Market Review will reserve its decision on the role of the STEM until the market power mitigation review has been completed. The Electricity Market Review acknowledges that eight of the nine submissions that addressed the STEM supported its retention,[24] though two of these (Bluewaters Power and Perth Energy) qualified their support by suggesting that the STEM should be voluntary.

4.7 Other matters raised in submissions

Some of the other matters raised by stakeholders in submissions are discussed in this section.

Constrained-on and constrained-off compensation

The retention of constrained-on compensation, with a modified calculation was broadly supported in submissions,[25] in order to fairly compensate a generator that is required to operate despite its offer price being higher than the reference node price.

Bluewaters Power and NewGen Power Kwinana suggested that a generator should receive constrained-off compensation payments when its output is curtailed as a result of an unplanned network outage. The Electricity Market Review observes that, under the current market design, a generator that is constrained off due to a network outage is required to log a Consequential Outage and is ineligible for constrained-off compensation payments. Consequently, the Electricity Market Review does not agree with the suggestion by Bluewaters Power and NewGen Power Kwinana. However, the Electricity Market Review acknowledges the underlying concern that generators are exposed to risks resulting from the actions of the network service provider and is separately investigating the framework for power system security and reliability, including consideration of the requirements and incentives for the network service provider.

[24] Alinta Energy opposed the proposal, suggesting that the STEM was a legacy system and that the cost to retain and transition it to the new market design was not warranted.

[25] See submissions by the Economic Regulation Authority Secretariat, ERM Power, Synergy, the WA Independent Power Association and Western Power. Alinta did not explicitly express support for this measure, but the existence of constrained-on compensation was assumed in Alinta's discussion of other matters.

Loss factor determination

Three stakeholders commented on the governance arrangements for loss factor determination, all supporting the transfer of responsibility for transmission loss factor determination to the Australian Energy Market Operator.[26] Of these, the Economic Regulation Authority Secretariat also provided support for retention of the current ability for a participant to request a reassessment of calculated loss factors, with the Economic Regulation Authority to take responsibility for conducting the audit (currently the responsibility of the Australian Energy Market Operator).

ERM Power suggested that the Australian Energy Market Operator should be required to perform yearly back cast reviews of its transmission loss factor calculations to assess the accuracy of its methods, along with explanations of substantial deviations between back cast values and forward-looking calculated loss factors for the coming year. The Electricity Market Review proposes that this suggestion be considered during the development of the Market Rule provisions governing the new arrangements for loss factor determination. The Electricity Market Review observes that Western Power is already required to provide written explanations of any change of more than 0.025 between an updated transmission or distribution loss factor and any previous value.[27]

Ex-post declaration of bilateral trades

Perth Energy suggested that consideration should be given to allowing ex-post declaration of bilateral energy trades, arguing that this would facilitate over-the-counter trading between market participants. The Electricity Market Review considers that this suggestion has merit and will investigate the viability during the detailed design process. The Australian Energy Market Operator has advised that its systems provide this capability in the National Electricity Market.

Energy Adequacy Assessment Projection

ERM Power suggested that there may be value in the adoption of the Energy Adequacy Assessment Projection framework from the National Electricity Market. ERM Power suggested that this projection, which uses probabilistic analysis to assess the risks of fuel restrictions (including water for hydro generation), provides a useful counterbalance to the deterministic comparison of available capacity and forecast demand in the Medium Term Projected Assessment of Supply Adequacy process. The Electricity Market Review agrees in the merit of combining both deterministic and probabilistic analyses when assessing supply adequacy and observes that both approaches form part of the current process for determining the Reserve Capacity Requirement.[28] This is expected to be supplemented by a role for the Australian Energy Market Operator in developing forecasts of network capacity and identifying NSCAS gaps, as described in section 4.3 above.

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[26] See submissions by the Economic Regulation Authority Secretariat, ERM Power and Western Power.

[27] See step 2.2.1(b)(ii) of the Market Procedure: Determining Loss Factors, available at http://wa.aemo.com.au/docs/default-source/default-document-library/determining-loss-factors.pdf?sfvrsn=0.

[28] The Reserve Capacity Requirement is set according to the planning criterion specified in clause 4.5.9 of the Wholesale Electricity Market Rules.

Reserve Capacity Mechanism

Several stakeholders discussed elements of the Reserve Capacity Mechanism.

- Alinta Energy enquired as to the future relationship between network connection agreements and the assignment of Capacity Credits. This matter is under current consideration by the Electricity Market Review (in the Reserve Capacity Mechanism project).
- ERM Power indicated that it did not support allocation of Capacity Credits for small intermittent non-scheduled generators, though it was apparent from a subsequent discussion with the Electricity Market Review that this statement was based on an understanding that large intermittent non-scheduled generators would also be ineligible for Capacity Credits. The Electricity Market Reviews confirms that that all intermittent non-scheduled generators will be eligible for Capacity Credits, but that non-intermittent non-scheduled generators will be ineligible.
- Perth Energy suggested that capacity refunds should not apply for a generator that is affected by network constraints. The Electricity Market Review confirms that this will be the case.
- Perth Energy advocated a full review of the allocation of capacity costs via Individual Reserve Capacity Requirements. The Electricity Market Review acknowledges Perth Energy’s concerns about the Individual Reserve Capacity Requirement calculation, particularly in relation to the interaction with the retail market, and intends to consider the allocation of capacity costs following the design of the capacity auction. However, the Electricity Market Review expects that only necessary changes to the Individual Reserve Capacity Requirement calculation will occur for 1 July 2018.

Power system security and reliability

The Australian Energy Market Operator indicated that the rules related to power system security and reliability need to be reviewed, including clear definition and delineation of the roles and responsibilities of the network service provider and the Australian Energy Market Operator. This is currently being considered by the Electricity Market Review.

Compliance and enforcement

The Economic Regulation Authority Secretariat suggested that the consolidation of some of the functions of the Authority and the Independent Market Operator provided an opportunity to streamline the compliance enforcement processes. The Electricity Market Review is transferring the compliance and enforcement functions from the Independent Market Operator to the Economic Regulation Authority and supports pragmatism in these processes. The Electricity Market Review proposes that this matter should be considered more fully during the detailed design process.

4.8 Matters not raised in submissions

The Electricity Market Review did not receive any comments in submissions on the matters listed below. For each of these matters, the final reform package reflects the proposals put forward in the Position Paper.

- Generators will be responsible for the commitment of their generating units.

- Generators will continue to be required to participate in the central outage scheduling and approval processes.
- The costs of the contingency lower service will continue to be allocated to customers according to their share of total consumption.
- Demand Side Programmes and Associated Loads will be retained.
- Flexibility will be retained in that all loads meeting the respective technical requirements (including first-tier loads) will be able to provide ancillary services, participate as scheduled loads and participate in Demand Side Programmes. In the cases of ancillary services and Demand Side Programmes, these loads could participate via a registered participant other than the financially responsible market participant.
- Capacity Credits for a generating unit will only be able to be allocated to the financially responsible market participant.
- The Small Generation Aggregator will not initially be included in the new market design.
- The existing Dispatch Support Service contract between Synergy and Western Power will be terminated on 1 July 2018. Western Power, the Australian Energy Market Operator and Synergy will be required to identify any services being provided under this contract that will be required in future under a network support agreement.

5. Benefits and costs of reforms to the Wholesale Electricity and Ancillary Service Market

The reforms to the wholesale energy and ancillary service markets are expected to lower costs, increase market transparency, improve competition between generators and improve investment signals. They will also bring the Wholesale Electricity Market into line with common practice in competitive electricity markets, particularly the National Electricity Market.

The reforms provide a practical, fit-for-purpose solution that addresses the problems described in the Position Paper and supports the objectives of the Electricity Market Review.[29] The new market design allows the Australian Energy Market Operator to leverage its systems, processes and expertise but is 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 reforms will 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 locational pricing) that would require major financial commitment down a path that diverges substantially from the National Electricity Market. The reforms do not lock the Wholesale Electricity Market into a particular long-term development path, allowing 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 new arrangements, further enhancements to manage the growth of new technologies or a full transition to the National Electricity Market.

This chapter focuses on the benefits of the reform package. Section 5.1 provides estimates of the efficiency benefits expected to be realised as a result of the proposed reforms. Additional benefits that cannot be quantified are described qualitatively in section 5.2, including an assessment of the way in which the reforms support the Electricity Market Review objectives.

5.1 Quantified benefits

Reduced energy costs due to earlier return of generators from outage

The gate closure time imposes a delay on a generator returning from maintenance. Later gate closure will reduce this delay, with the potential to increase competition and reduce costs to consumers where the generator returning to service has lower operating costs than the marginal price.

[29] The Electricity Market 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.

To estimate the benefit of earlier return from maintenance, 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 would likely increase if gate closure is shortened further. The results are presented in Table 5.1.

Table 5.1: 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

A recurring benefit of $300,000 per annum has been incorporated in both the High and Low cases in the summary analysis at the end of this section.

Reduced load following costs resulting from shorter dispatch cycle

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[31] was used to produce a forecast of the total requirement for dispatch of scheduled generators in the next dispatch interval.[32] 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.

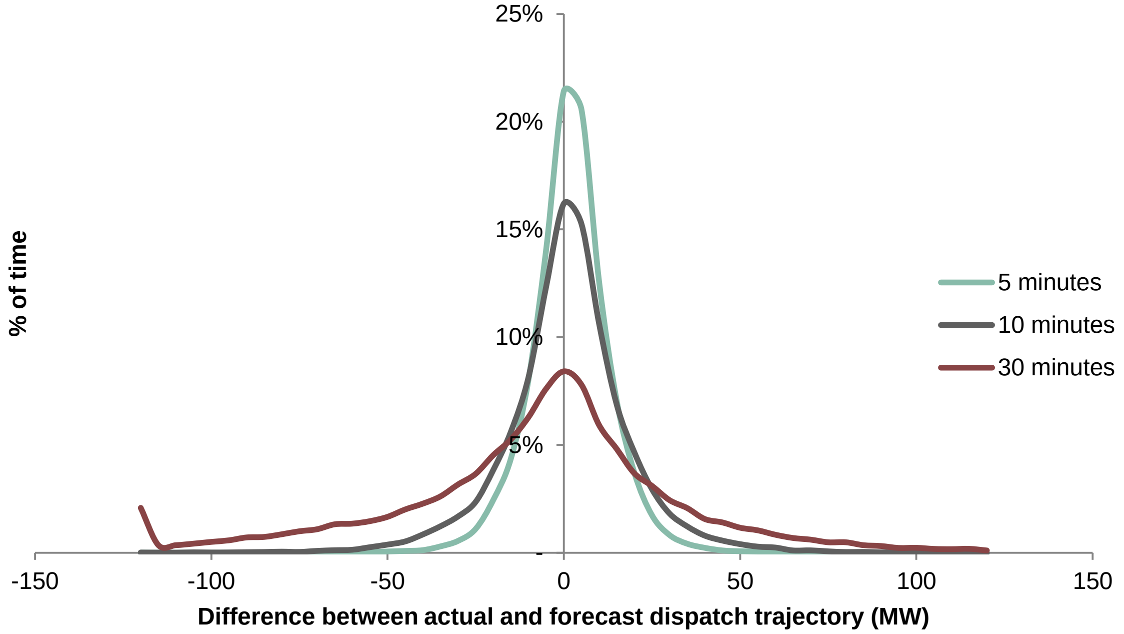
[30] Market data from July 2014 to June 2015 was used for this analysis. Synergy generators were excluded from this analysis as the current portfolio dispatch approach means that the return to service of a generator within the portfolio is not restricted by the gate closure time.

[31] Data from October 2014 was used.

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

Figure 5.1 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[33], even a conservative 30 per cent reduction in forecasting error could reduce the total load following requirement by around 15 per cent.

Figure 5.1: 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. Scheduled generators are currently dispatched at their maximum ramp rate, 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 dispatch 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.[34] 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.

[33] 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.

[34] 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.

These approaches are shown schematically in Figure 5.2,[35] while the results of the analysis are shown in Figure 5.3. 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 a five-minute dispatch cycle could reduce the total load following requirement by 20 per cent.

Figure 5.2: Schematic representation of dispatch cycle and ramping deviations

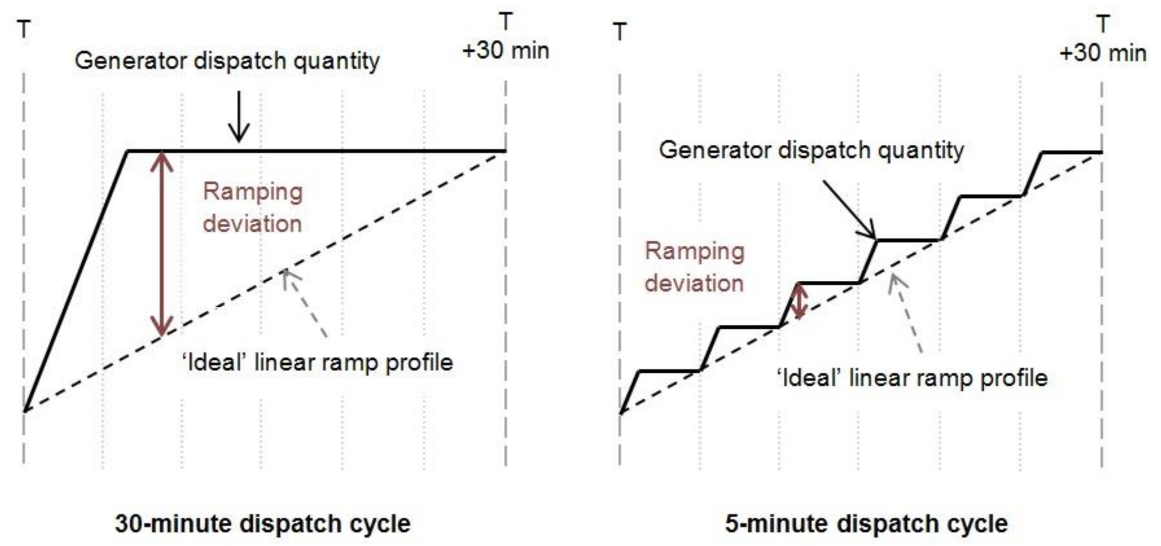
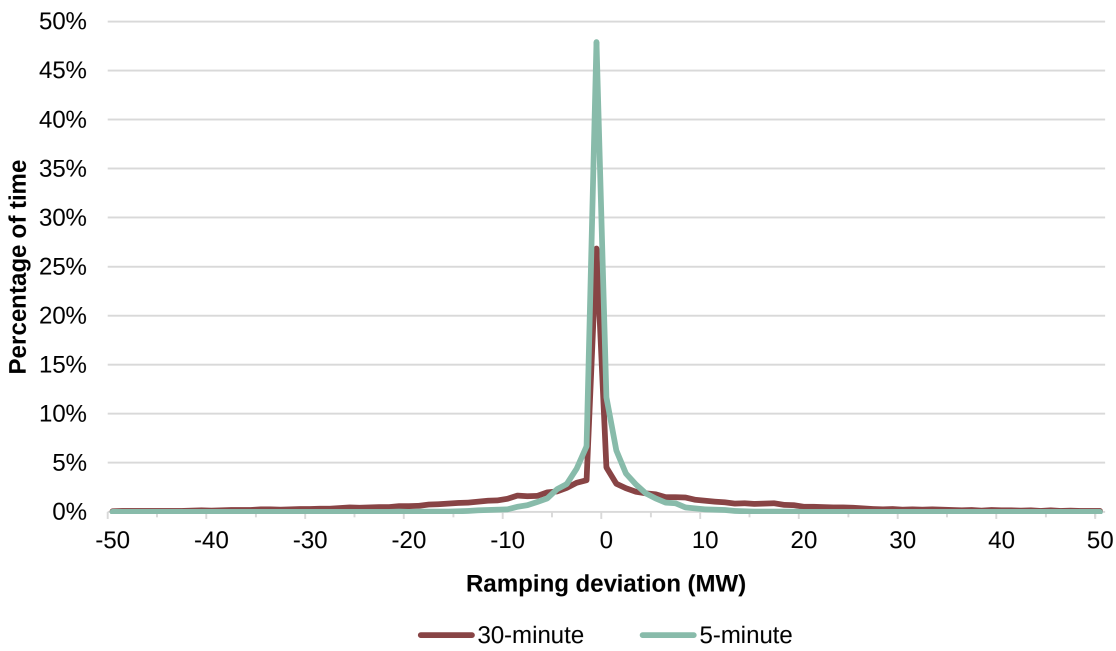


Figure 5.3: Ramping deviation improvement due to shorter dispatch cycle



Source: Australian Energy Market Operator

[35] NEMDE has the capability to vary the ramp rate within a dispatch instruction in order to more accurately match generator dispatch to forecast demand, which would theoretically eliminate ramping deviations. However, different generators may have varying abilities to vary their ramp rate, so this incremental benefit has been excluded from the analysis.

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 that is actually being used;
- it is possible that some load following is provided by the Synergy portfolio but not paid for by the market; and
- a proportional reduction in the load following requirement can result in the load following market clearing at a lower price, meaning that the total load following cost reduces by a greater proportion.[36]

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 for the 12-month period ending on 31 March 2015[37] as a guide, it can be conservatively estimated that a combined 35 per cent reduction in the load following requirement described in this section would result in cost reductions of between $10 million and $20 million per annum. Recurring benefits of these magnitudes have been incorporated in the Low and High cases, respectively, in the summary analysis at the end of this section.

Improved efficiency of energy dispatch

The reforms to the wholesale energy and ancillary service markets include many elements that will provide material efficiency benefits, but for which quantitative analysis of the benefits is infeasible, predominantly due to the current lack of transparency of costs and the extent of cross-subsidies in the market. Such benefits include:

- productive efficiency gains, to the extent that the co-optimisation of energy and ancillary services results in dispatch outcomes with a lower total cost than the current, distinct processes for energy and ancillary services;
- improved decision-making by market participants and increased competition resulting from increased transparency and better quality dispatch forecasts, that are produced closer to real-time (due to the shorter dispatch cycle and later gate closure) and account for network congestion (due to the security-constrained market design);
- reductions in the risk premium within offer prices, due to the risk of participation being reduced through ex-ante pricing, later gate closure and the co-optimisation of energy and ancillary services;
- improved transparency of ancillary service costs and removal of cross-subsidies from within the Synergy portfolio;
- greater control and flexibility for Synergy to optimise the operation of its power stations through facility bidding;

[36] For example, if a 10 per cent reduction in the load following requirement caused the load following price to reduce by 10 per cent, the total load following cost (price times quantity) would be reduced by 19 per cent.

[37] 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.

- 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;
- improved longer-term efficiency through increased scope for competition in the provision of ancillary services;
- improved utilisation of the transmission network, as greater automation in the calculation of network constraints allows constraints to be set less conservatively without compromising system reliability; and
- improved network investment decision-making through accurate quantification of the costs arising due to network congestion.

The Electricity Market Review conservatively estimates that these efficiency benefits could result in energy cost savings in the order of one to two per cent of annual energy costs, though the long-term nature of some of these benefits means that they will increase over time. The total energy cost for the Wholesale Electricity Market for the 2015-16 financial year was in excess of $900 million.[38] Consequently, recurring benefits have been incorporated in the summary analysis at the end of this section, building proportionally over five years to $9 million and $18 million per annum for the Low and High cases respectively.

Avoided system costs

The reforms to the wholesale energy and ancillary service markets will enable the Wholesale Electricity Market to avoid some system development and maintenance costs that would have been incurred in the absence of the reforms. These include:

- the development and maintenance of a bespoke constraint management tool for system operation, which would have been required in order to facilitate the connection of new generators;[39]
- the development and maintenance of a replacement wholesale settlement system for the Australian Energy Market Operator; and
- reduced operational efficiency for the Australian Energy Market Operator to operate and maintain disparate systems between the Wholesale Electricity Market and National Electricity Market.

The summary analysis at the end of this section includes avoided capital costs of $6 million and recurring cost reductions of $1 million per annum in the Low case, and avoided capital costs of $10 million and recurring cost reductions of $2 million per annum in the High case.

[38] Calculated from Balancing Price data and Operational Load Estimate data available at http://data.wa.aemo.com.au/#balancing-summary and http://data.wa.aemo.com.au/#operational-measurements respectively.

[39] Western Power's application for an exemption to the Technical Rules in respect of the Byford PV Solar Farms described the development of a Network Constraint Tool to manage the increased network congestion due to the volume and location of new generation connections. Documents related to this application are 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.

Summary analysis

Table 5.2 summarises the quantified benefits for the Low and High cases discussed in this section. The quantified benefits of the reforms to the wholesale energy and ancillary service markets are estimated to be between $190 million and $375 million in present value terms.

Table 5.2: Present value of quantified benefits

Benefit or avoided cost	Low		High	
	Capital benefit ($m)	Recurring benefit ($m)	Capital benefit ($m)	Recurring benefit ($m)
Earlier return of low-cost generators from outage	-	0.3	-	0.3
Load following cost reduction due to shorter dispatch cycle	-	10	-	20
Improved energy dispatch efficiency	-	9 (1)	-	18 (1)
Avoided system development/maintenance costs	6	1	10	2
Present value (2)	**$189.8 million**		**$374.7 million**	

(1) The benefits of improved energy dispatch efficiency are expected to increase over time. These benefits have been modelled as building proportionally over five years, i.e. 20 per cent realised in the first year, 40 per cent realised in the second year, and so on.

(2) The present value of benefits has been calculated using a discount rate of eight per cent over 20 years. 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.

This assessment of benefits arising from the reforms to the Wholesale Electricity Market relates only to direct benefits and does not reflect the additional indirect benefits to the wider economy from having a transparent, dynamic and efficient electricity sector. Given the criticality of electricity as an input for the majority of economic activity, reductions in production and administration costs can improve the productivity and competitiveness of the Western Australian economy and reduce cost of living pressures.

5.2 Unquantified benefits

Alignment with the National Electricity Market

The package of reforms provides for closer alignment with the National Electricity Market. As noted in the previous section, this would allow the Australian Energy Market Operator to leverage its systems, processes and expertise, reducing implementation and ongoing operational costs for Western Australian consumers. The use of common systems between the Wholesale Electricity Market and the National Electricity Market allows for economies of scale and enables access to sophisticated software and processes that might be unaffordable for the Wholesale Electricity Market in isolation.

The alignment of the proposed market design with the National Electricity Market would also 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. 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.

Alignment with the Electricity Market Review objectives

The Electricity Market Review has three objectives.

- The first objective is reducing costs of production and supply of electricity and electricity related services, without compromising safe and reliable supply. As outlined in section 5.1, the reforms to the energy and ancillary service markets are expected to deliver substantial cost reductions.
- The second objective is reducing the State 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. The achievement of this objective depends on how well the private sector is encouraged to invest in generation in the Wholesale Electricity Market. The current market design can create perceptions of conflict of interest and inequitable treatment, with its hidden efficiencies and cross-subsidies, 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).

  The proposed reforms support the objective by removing perceived investment risks and providing additional options for participation in the market. They will end most of the legacy arrangements for Synergy in the market, improve transparency and remove cross-subsidies. By removing the special arrangements for the dispatch of Synergy's generating units, the resulting market design would appear much more familiar and conventional to investors that operate in other electricity markets and would allow Synergy to be treated no differently than other market participants so that it can compete in the market on equal terms.
- The third objective is attracting to the electricity market private-sector participants that are of a scale and capitalisation sufficient to facilitate long-term stability and investment. 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. 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.

5.3 Implementation cost of reforms

The Position Paper sought submissions from stakeholders detailing the costs that must be incurred by market participants as a result of the proposed reforms. Stakeholders generally advised that the proposed reforms were not sufficiently developed to allow them to accurately estimate their implementation costs. However, Western Power advised that it had not identified any material costs associated with the proposed reforms in the Position Paper that were not a consequence of other Electricity Market Review reforms (particularly the network regulation and metering reforms).

The Electricity Market Review acknowledges that the Australian Energy Market Operator and Synergy will face the largest implementation costs.

- In subsequent correspondence, the Australian Energy Market Operator has estimated that its costs to develop and implement new market and dispatch systems and to prepare market procedures will be between $25.3 million and $33.6 million.[40] The Electricity Market Review considers this cost to be relatively inexpensive; the implementation of an alternative market and dispatch engine would be expected to cost at least double this level of expenditure.
- Synergy is likely to face greater implementation costs than other market participants due to the size of its generation portfolio, the need to implement facility bidding and dispatch and the need to transition away from System Management acting as its dispatch agent. The Electricity Market Review is liaising with Synergy, with support from the Australian Energy Market Operator, to assist it in estimating its costs over the coming months.

The Electricity Market Review also acknowledges that other market participants will incur costs in preparing for the new market design. In addition, the Electricity Market Review forecasts that it will incur expenses of approximately $3 million for commercial and regulatory development work and $1 million for legal resourcing to undertake the detailed design and drafting of Wholesale Electricity Market Rules.

In aggregate, total implementation costs for these reforms are expected to be between $60 million and $100 million across all market participants. However, the quantifiable benefits and avoided costs described in section 5.1, estimated to be between $190 million and $375 million in present value terms, will far exceed the implementation costs of the reforms.

[40] This figure includes costs for systems to support power system operation. The Electricity Market Review observes that some or all of these costs would be incurred even in the absence of reform to the wholesale energy and ancillary service markets, as a result of the transfer of System Management from Western Power to the Australian Energy Market Operator.

However, this figure excludes costs associated with retail market operation and some of the costs related to settlement systems, which are attributed to the transfer of retail market operation from Western Power to the Australian Energy Market Operator. It is expected that the Australian Energy Market Operator will include these costs in its Allowable Revenue submission to the Economic Regulation Authority.

6. Implementation of reforms

The reforms to the energy and ancillary service markets are required to take effect on 1 July 2018 to align with the commencement of the constrained network access model within the national framework for network regulation. This will ensure consistency between the energy market design and the network connection and access framework.

Stakeholders suggested in submissions that the achievement of this implementation timeframe will be reliant on:

- timely finalisation of policy decisions on critical matters such as the choice of reference node, rules related to power system security and reliability, the basis of dispatch and settlement cycles;
- timely development of Market Rule provisions to provide certainty for market participants who must modify their systems; and
- market participants receiving support from the Australian Energy Market Operator to assist in their readiness, including training, timely provision of technical specifications and adequate time for system testing.

Table 6.1 identifies the high level deliverables and milestones for the implementation process and provides an indicative timeline.

Table 6.1: High level deliverables and milestones

Activity	Lead organisation	Timing
Ministerial approval to implement reforms		July 2016
Detailed design and drafting of Wholesale Electricity Market Rules	Electricity Market Review	Aug 2016 - mid 2017
System development and testing	AEMO	Sep 2016 - Feb 2018
Procedure drafting	AEMO, Economic Regulation Authority	Oct 2016 - Feb 2018
Training of market participants	AEMO	Late 2016 – mid 2018
Commencement of early/transitional Wholesale Electricity Market Rules to facilitate preparations	Electricity Market Review	Mid 2017 - early 2018
Preparatory activities (pre-registration, qualification for ancillary service markets, etc.)	AEMO	Mid 2017 - early 2018
Market trials	AEMO	March - June 2018
Commencement of new energy and ancillary service markets		**1 July 2018**

The most onerous activities in the implementation process are anticipated to be:

- detailed design and drafting of Wholesale Electricity Market Rules, to be led by the Electricity Market Review;

- drafting of market procedures, to be led by the Australian Energy Market Operator and the Economic Regulation Authority, which will each be responsible for its own procedures; and
- system development and testing, to be coordinated by the Australian Energy Market Operator.[41]

Close coordination between these activities will be required. The Electricity Market Review and Australian Energy Market Operator are currently preparing detailed implementation plans, including identification of the interactions and dependencies between the various processes. These plans will be shared with stakeholders in the coming months.

The main activities are described in further detail in the sections below.

Detailed design of operations and processes

The finalised reforms outlined in this report 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. This process will be supported by a targeted industry working group, convened by the Electricity Market Review. Design papers developed through this process will be made available for wider consultation.

Drafting of amendments to the Wholesale Electricity Market Rules

Given the breadth of amendments to the Wholesale Electricity Market Rules that will take effect on 1 July 2018, including those emanating from other projects within the Electricity Market Review, the most practical method to make amendments will be to repeal and replace the Wholesale Electricity Market Rules on 1 July 2018.

The Electricity Market Review will lead the development of the new Wholesale Electricity Market Rules, supported by an industry working group. While it is expected that drafting work will be substantially completed by the third quarter of 2017, it is very likely that further amendments will be identified in the period leading up to 1 July 2018, as the new systems and processes are developed and tested. Consequently, the Electricity Market Review may need to continue to maintain the rules during this interim period.

It is expected that some transitional amendments to the Wholesale Electricity Market Rules will be required to allow for preparatory work to occur prior to 1 July 2018. For example, transitional amendments are likely to be required in the areas of registration, capacity certification and loss factor determination. The mechanism by which these amendments will be effected will be determined at a later date.

[41] Market participants will need to liaise with the Australian Energy Market Operator during their own system development and testing processes.

During the detailed design process, the Electricity Market Review will also consider the merits of early progression of some rule changes in advance of 1 July 2018. Several stakeholders suggested that changes to scheduling day processes, such as the removal of Resource Plans and extension of the STEM submission window, could be implemented earlier.[42] A decision on whether to implement these changes early is dependent upon the outcomes of the review of market power mitigation described in section 4.6.

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. It will also be responsible for supporting the system development activities of other participants, including timely provision of technical specifications and coordination of system testing.

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 March 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

The Electricity Market Review will form an industry working group during the third quarter of 2016 to assist with the detailed design process and provide feedback on rule drafting. The Electricity Market Review advises that membership of this working group will be by invitation, as it will not be able to accommodate all market participants. To supplement the working group, the Electricity Market Review will periodically organise, or present at, broader industry workshops 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.

In addition, the Electricity Market Review anticipates that the Australian Energy Market Operator will establish one or more working groups to support the development of market procedures and information technology system development. The Australian Energy Market Operator will provide updates to market participants when further information is available.

[42] See submissions by Alinta Energy, Bluewaters Power, NewGen Power Kwinana and Synergy.