Government of **Western Australia**
Department of **Mines, Industry Regulation and Safety**
Energy Policy WA

Cost Allocation Review

International Review

Conducted by Marsden Jacob Associates

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Working together for a **brighter** energy future.

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Energy Policy WA
Level 1, 66 St Georges Terrace
Perth WA 6000

Locked Bag 100, East Perth WA 6892
Telephone: 08 6551 4600

www.energy.wa.gov.au
ABN 84 730 831 715

Enquiries about this report should be directed to:

Email: energymarkets@dmirs.wa.gov.au

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Abbreviations

Term	Definition
AGC	automatic governor control
AEMO	Australian Energy Market Operator
BSUoS	Balancing Service Use of System
BMPV	behind-the-meter photovoltaic
CAISO	California Independent System Operator
CARWG	Cost Allocation Review Working Group
DER	distributed energy resources
DNSP	distribution network service provider
DRSP	demand response service provider
EPWA	Energy Policy WA
ERCOT	Electricity Reliability Council of Texas
ESB	Energy Security Board
ESS	Essential System Services
FFR	Fast Frequency Response
Taskforce	Energy Transformation Taskforce
FCAS	Frequency Control Ancillary Services
FCESS	Frequency Control Essential System Services
FERC	Federal Energy Regulatory Commission
GW	gigawatt
GWh	gigawatt hour
ISO	Independent System Operator
I-SEM	Integrated Single Electricity Market
kW	kilowatt
kWh	kilowatt hour
LRET	Large-scale Renewable Energy Target scheme
MAC	Market Advisory Committee

Term	Definition
MASP	market ancillary service provider
MNSP	managed network service provider
MPC	maximum price cap
MW	Megawatt
MWh	megawatt hour
NCESS	Non-Co-Optimised Essential System Services
NEM	National Electricity Market
NEMS	The National Electricity Market of Singapore
NMI	National Meter Identifier
NSP	Network Service Provider
PJM	Pennsylvania, New Jersey, and Maryland Interconnection
PV	Photovoltaic
QMS	quality management system
RoCoF	Rate of Change of Frequency
RCM	Reserve Capacity Mechanism
SCADA	supervisory control and data acquisition
SGA	small generation aggregators
SRAS	System Reserve Ancillary Service
SRES	small-scale renewable energy scheme
SWIS	South West Interconnected System
TNSP	Transmission Network Service Provider
TUoS	Transmission Use of System
VRE	variable renewable energy
WEM	Wholesale Electricity Market

Executive Summary

Introduction

The Coordinator of Energy (Coordinator), in consultation with the Market Advisory Committee (MAC), is undertaking a Cost Allocation Review, which is a review of the allocation of Market Fees and Essential System Services (ESS)[1] costs to Market Participants. The Cost Allocation Review is being conducted under clause 2.2D.1 of the Wholesale Electricity Market (WEM) Rules.

EPWA has appointed Marsden Jacob Associates (Marsden Jacob) to support the Cost Allocation Review, which will consider the allocation of Market Fees and various aspects of the allocation of ESS costs that, due to time constraints, were not fully considered by the Energy Transformation Taskforce (Taskforce).

Purpose of this Report

This report has been prepared by Marsden Jacob on the basis of a literature review of methodologies used to allocate Market Fees and ESS costs in the following jurisdictions:

- the WEM in Western Australia;
- the National Energy Market (NEM) in Australia;
- the National Electricity Market of Singapore (NEMS);
- the California Independent System Operator (CAISO) in California;
- Electricity Reliability Council of Texas (ERCOT);
- the Pennsylvania, New Jersey, and Maryland (PJM) Interconnection;
- I-SEM, Ireland; and
- Great Britain (National Grid).
- This report summarises the methods used to allocate market services and Ancillary Services (or ESS) costs in various jurisdictions, and the justification for these methods.

Jurisdictional Review

Chapters 2 to 9 summarise the charging practices for Market Fees and Ancillary Services (or ESS) for each of the jurisdictions reviewed, and Appendix A provides a detailed summary and comparison table, including an assessment of whether the current or proposed charging practices in each jurisdiction reflect the causer-pays principle (low to high adherence) and an indication of whether cost allocation is based on the beneficiary-pays principles (where applicable).

Table 1 provides a high-level summary of Appendix A.

[1] ESS and ancillary services are terms used to describe services that are required to maintain supply reliability in real time. This includes maintaining and controlling system frequency, reactive energy, voltage and providing system restart services.

Table 1: Adherence to Causer-Pays for Market Fees and Ancillary Services, by Jurisdiction

Service Category	Service	Cost Recovery Method	Causer-Pays Adherence
WEM			
Market and System Operator		Charge on Grid MWh for Market Participants	Medium Partially excludes other causers such as distributed energy resources (DER) and fully excludes network operators.
Ancillary Services	Frequency Regulation	Loads and intermittent generators (Grid MWh).	Low Frequency regulation costs are not driven by Grid MWh consumed or generated. Other causers are excluded, such as scheduled generators and DER.
	Contingency Reserve Raise	Modified runway method to allocate costs to generators.	High More of the costs allocated to the largest generator operating in a Trading Interval. Is consistent with causer-pays methodology.
	Contingency Reserve Lower	Allocated to loads based on Grid MWh.	Medium Costs allocated across all loads, which includes large commercial and industrial loads who are the major 'causer' of the requirement for this service. Batteries (recharging) will be a major causer of this service in the future.
	Inertia	Loads, network operator and generators.	Medium Costs split evenly between beneficiaries, which provides incentives for participants to improve 'ride-through' capability of equipment.

Service Category	Service	Cost Recovery Method	Causer-Pays Adherence
NEM (Australia)			
Market Operator		Mixture of fixed and variable charges on participants (includes aggregators) and network operators.	Medium However, includes variable charges even though these costs do not vary with usage or demand. Competition considerations could be important, as moving from a $/MWh to a $/user charge will have relatively larger impacts on smaller retailers/aggregators and could be seen as a barrier to entry.
Ancillary Services	Frequency Regulation	Causer-pays methodology to determine contribution factors for loads and generators.	High
	Contingency Reserve	Grid MWh for loads and generators.	Medium
NEMS (Singapore)			
Market Operator		Fixed and variable fees on market participants.	High
Ancillary Services	Regulation	Loads and first 10 MW of each generation Facility being dispatched.	Medium
	Reserve	Variant of runway model to calculate costs for each dispatchable Facility	High Most costs allocated to largest generator in operation.
CAISO			
Market Operator		Unbundled Grid management charge on service users ($/MWh).	Low. Consistent with beneficiary-pays principle.
Ancillary Services		Unit charge on Load Serving Entities.	Low

Service Category	Service	Cost Recovery Method	Causer-Pays Adherence
ERCOT			
Market Operator		Unit charge on Qualified Scheduling Entities based on load.	Low
Ancillary Services	Regulation	Unit charge on Load Serving Entities.	Low
	Reserve	Unit charge on Load Serving Entities.	Low
PJM			
Market Operator		Unit charges on transmission users.	Medium
Ancillary Services	Regulation	Unit charge on Load Serving Entities.	Low
	Primary Reserve	Unit charge on Load Serving Entitles.	Low
I-SEMS			
Market Operator		Part of TUoS tariff (unbundled) on transmission users (generators and loads).	Low
Ancillary Services	System Services	Part of TUoS tariff (unbundled) on transmission users (generators and loads).	Low
Great Britain			
Market Operator		Part of BSUoS Charge.	Low Uses beneficiary-pays principle. Allocated to customer's gross demand.

Service Category	Service	Cost Recovery Method	Causer-Pays Adherence
Ancillary Services		Part of BSUoS Charge.	Low Uses beneficiary-pays principle. Allocated to customer's gross demand.

Notes: (a) *Grid MWh – refers to electricity demand (net) that is met by large-scale Facilities that operate in wholesale electricity markets. Excludes 'behind-the-meter' generation or storage.*

(b) *Gross demand – Total electricity demand met by all generation in a system (includes behind-the-meter generation / storage). Also referred to as Gross MWh.*

Source: *Marsden Jacob 2022*

Marsden Jacob makes the following observations:

- Market Fees:
  - The NEM has made significant inroads to achieving the causer-pays principle (it included 'causers' of costs, such as network users and aggregators). However, the NEM still has a high dependence on Grid MWh charging, which is not a cost driver for AEMO fees.
  - The approach in the NEM falls short of Great Britain's approach to charge customers based on gross demand, which ensures that DER contributes to cost recovery. The Great Britain approach accepts that pricing of these market services is about cost recovery and not sending efficient price signals to change behaviour (i.e., to encourage transmission users to use less market services). On this basis, they conclude there are not good efficiency arguments for levying charges on Market Participants. Charges should simply be levied on ultimate beneficiaries of the service (i.e., final customers) or Gross MWh to reduce complexity and remove other distortions in the market.
- Regulation Services – the NEM uses a causer-pays methodology to determine contribution factors for allocating costs. This provides incentives for Market Participants to reduce variability in generation and loads.
- Reserve Raise – both Singapore and the WEM use the runway methodology to allocate costs to generators, which is consistent with causer-pays approaches.
- Reserve Down – the WEM allocates costs to loads given that they are likely the causer of the requirement for this cost (loss of load). However, the major causer of the requirements for this service are large industrial and commercial loads (i.e., loss of a large load which causes system frequency to rise rapidly), who would pay a higher proportion of costs under a causer-pays methodology, compared to smaller users.
- Inertia – the WEM has a formal unbundled Rate of Change of Frequency (RoCoF) service which allocates costs to generators, loads and network operators (1/3 cost attribution for each of Registered Facilities, network operators, end-users) which is consistent with the beneficiary-pays principle.

1. Scope of Work

1.1 Introduction

The Coordinator of Energy (Coordinator) is conducting the Cost Allocation Review under clause 2.2D.1 of the Wholesale Electricity Market (WEM) Rules, in consultation with the Market Advisory Committee (MAC). The Cost Allocation Review is a review of the allocation of Market Fees and Essential System Services (ESS) costs to Market Participants.

EPWA has appointed Marsden Jacob Associates (Marsden Jacob) to support the Cost Allocation Review, and the MAC has established the Cost Allocation Review Working Group (CARWG).

Further information on the Cost Allocation Review is available on the EPWA website (https://www.wa.gov.au/government/document-collections/cost-allocation-review-working-group), including the Scope of Works for the review, the Terms of Reference for the CARWG, meeting papers and minutes for all CARWG meetings.

1.2 Purpose of this Report

This report has been prepared by Marsden Jacob on the basis of a literature review of methods used to allocate Market Fees and ESS costs in various jurisdictions and to provide key insights for the Cost Allocation Review. The literature review covers the following jurisdictions:

- the WEM in Western Australia;
- the National Electricity Market (NEM) in Australia;
- the National Electricity Market of Singapore (NEMS);
- the California Independent System Operator (CAISO) in California;
- Electricity Reliability Council of Texas (ERCOT);
- the Pennsylvania, New Jersey, and Maryland (PJM) Interconnection;
- I-SEM, Ireland; and
- Great Britain (National Grid).

1.3 Approach to the Jurisdictional Review

The cost allocation methods for each jurisdiction have been compared and contrasted based on the following:

- market design and key market mechanisms (energy markets, capacity markets and ancillary service markets);
- proportion of market operator fees and ancillary service charges recovered;
- current cost allocation method for fees and Ancillary Services;
- current cost allocation to different classes of users – generators, loads, storage providers, hybrid Facilities, aggregators, and network operators;
- how much of the cost falls on final customers and distributed energy resources (DER);
- key considerations in the development of those methods;
- recent or planned changes to cost allocation methods and justification for the change;

- user-pays or beneficiary-pays principles in the development of cost allocation methods;
- economic efficiency in the development of cost allocation methods (including cost to implement causer-pays or user-pays cost recovery);
- convention or precedent in the development of cost allocation methods (i.e., easy to understand, low implementation cost and low efficiency losses by not adopting causer-pays principle); and
- applicability of other jurisdictional approaches to the WEM, given the WEM's capacity and energy market design.

1.4 Structure of this Report

The structure of the report is provided below.

- Chapter 1: scope of work for the study;
- Chapter 2: review of the WEM cost allocation methods;
- Chapter 3: review of the NEM cost allocation methods;
- Chapter 4: review of the NEMS cost allocation methods;
- Chapter 5: review of the CASIO cost allocation methods;
- Chapter 6: review of the ERCOT cost allocation methods;
- Chapter 7: review of the PJM cost allocation methods;
- Chapter 8: review of the I-SEM cost allocation methods;
- Chapter 9: review of the National Grid cost allocation methods;
- Chapter 10: fast frequency response
- Chapter 11: comparison of jurisdictional approaches to cost allocation;
- Chapter 12: implications of the jurisdictional review for the Cost Allocation Review;
- Appendix A: mapping of market services and ESS in each jurisdiction to WEM service equivalents; and
- Appendix B: Market Fees and Ancillary Services recover by jurisdiction.

2. Wholesale Electricty Market

2.1 Market Design and Market Mechanisms

The WEM is a 'capacity plus energy market' where capacity and energy are traded separately. In addition, there are ESS markets and administered ESS mechanisms that will be redesigned in the future.

The WEM was designed under the assumption that most energy would be traded via bilateral contracts. That is, a Market Participant would typically have a zero net contract position (bilateral contracts or physical generation would supply the majority of a retailer's load). As a result, the markets were designed to facilitate trade or manage imbalances around Market Participant's net contract positions. These markets include:

- the Short Term Energy Market (STEM) – which enables participants to purchase or supply energy the day before the trading day – effectively a short-term hedge; and
- the Balancing Market – which accounts for imbalances between a Market Participant's net contract position (after STEM nominations) on the scheduling day (day before trading) and their actual position on the trading day.

The Balancing Market will be renamed the Real-Time Energy Market under the reforms and its primary purpose will be to ensure the efficient dispatch of generation (and storage in the future) to meet demand in each Trading Interval (currently 30 minutes, changing to 5 minutes).

Actual participation via price-based dispatch in the Balancing Market is mandatory for generating Facilities with a sent out capacity of 10 MW or more. Generation plant is dispatched on the merit order of bids, with the cheapest generation plant dispatched before more expensive plant, as necessary, to meet the load in a Trading Interval (although there are deviations from merit order dispatch due to network constraints).

2.2 Reserve Capacity Mechanism

The Reserve Capacity Mechanism (RCM) is an administered capacity market that is designed to ensure that there is adequate generation capacity available in the system to meet forecast peak electricity demand plus a margin to allow for forecast errors or plant failures. Under the RCM, generation plant (both intermittent and dispatchable plant), energy storage and Demand Side Management Facilities are certified and allocated Capacity Credits. Market Customers are required to procure Capacity Credits in proportion to their share of the electricity load in periods of peak electricity demand. The retailers may meet this obligation by either purchasing Capacity Credits directly from generators under bilateral contracts or procuring Capacity Credits via the AEMO at the administered price (known as the Reserve Capacity Price or RCP).

Generators receive a separate revenue stream for providing capacity, which removes the need for the energy markets to be subject to high and volatile energy prices like in the NEM. High price events in the NEM (prices at or near the price cap of $15,000/MWh) are not necessary to provide revenue for peaking Facilities and to trigger new investment. Instead, energy prices are capped at lower levels ($511/MWh for plants running on diesel and $267/MWh for all other plant).

The Coordinator is currently reviewing the RCM, which also incorporates a review of the Planning Criterion and how Facilities will be accredited for Capacity Credits in the future.

2.3 Essential System Services

Essential System Services (ESS) previously known as Ancillary Services) are required to ensure a secure and reliable electricity supply. ESS are required to maintain system frequency due to a sudden large change in generation or load, as well as providing Load Following Services to balance demand and supply within each 30-minute Trading Interval. The current Ancillary Services will be replaced by Frequency Control ESS, like the NEM ancillary service standards, and include:

- Frequency Regulation Raise (currently referred to as Load Following Ancillary Services Up or LFAS Up);
- Frequency Regulation Lower (currently referred to as LFAS Down);
- Contingency Reserve Raise (currently referred to as Spinning Reserve Ancillary Service or SRAS);
- Contingency Reserve Lower (currently referred to as Load Rejection Reserve or LRR); and
- Rate of Change of Frequency (RoCoF) Control Service (no current equivalent service).

It is likely that grid connected battery systems (2 hours) will be able to provide the first four services in preference to coal or gas fired generation over the next decade because a battery system's response times are superior to the response times of coal or gas fired generation, even when the later technologies are operating (i.e., generation units that are operating can ramp up and down quicker when compared to a warm or cold start unit).

A formalised RoCoF Control Service was not previously required because most of the generation fleet consisted of large coal and gas units that had provided significant inertia (stabilised system frequency) through normal operations. With the expected retirement of many of these units over the next decade, batteries and intermittent plant (e.g., wind) will need to provide synthetic inertia.

RoCoF Control Service will perform the following functions:[2]

- to restrict the RoCoF to below a certain level (e.g., 1-2 Hz/second) (the amount of RoCoF Control Service scheduled to meet this purpose is referred to as the minimum RoCoF requirement); and
- to provide a substitute for Contingency Reserve Raise (the more inertia there is in the power system at any given point in time, the less Contingency Reserve Raise is required).

AEMO will determine a safe RoCoF limit through technical studies and include it in the Frequency Operating Standard and the dynamic frequency contingency model used in dispatch. The implication of this service is that higher marginal cost synchronous generators will need to operate ahead of cheaper intermittent renewable generators.

Maintaining a minimum level of inertia could be achieved by constraining on additional synchronous generators or by commissioning a high inertia synchronous condenser. Some inverter connected generators (e.g., wind farms) and batteries can also provide a synthetic inertial response.[3] Battery energy storage systems (BESS) can provide a rapid change in the power generated or consumed; this fast frequency response can also help to control RoCoF.

2 AEMO, Market settlement, Implementation of five-minute settlement, uplift payments and Essential System Services settlement, 1 December 2019

3 The current RoCoF rules do not permit synthetic inertia, but this is likely to be reviewed in the future.

2.4 Recovery of Market Fees and ESS Costs

2.4.1 Market Services

Fees are levied as follows:

- Market Fees to recover costs for AEMO's market operations, system planning and market administration services;
- System Operation Fees to recover AEMO's costs for its system operation services;
- Regulator Fees to recover the Economic Regulation Authority's (ERA) costs for its monitoring, compliance, enforcement, and regulation services; and
- Coordinator Fees to recover the costs for its functions under the WEM Rules plus the costs and expenses for the Chair of the MAC.

Each Market Participant is charged a fee based on the Market Fee, System Operation Fee, Regulator Fee and Coordinator Fee rates and their sent out generation and/or load for all their Registered Facilities and Non-Dispatchable Loads for all Trading Intervals for the day.

The budget and fees for 2020-21 and 2021-22 are shown in Table 2. Total fees are around $1.788/MWh, which represents 0.5% of the annual bill of a residential customer in the SWIS.[4]

Table 2: WEM Market Fees and Budget (selected years)

	Budget 2020/21	Budget 2022/22
Revenue Requirement ($m)	31.7	30.8
Energy Consumption (GWh)	27,589	17.078
WEM Market Operator fee ($/MWh)	0.380	0.380
WEM System Management fee ($/MWh)	0.514	0.514
WEM fee ($/MWh)	0.894	0.894
WEM fee (indicative benchmark) ($/MWh)	1.788	1.788

Source: AEMO, 2021-22 Budget and Fees

2.4.2 Application of Causer-Pays Principles to ESS Cost Recovery

The Energy Transformation Taskforce (Taskforce) has made several recommendations regarding the application of causer-pays principles to ESS cost recovery – see Table 3. The cost allocation methodologies recently considered by the Taskforce that have resulted in changes in WEM Rules, such as application of the runway method or the RoCoF cost recovery method are out of scope for the Cost Allocation Review (apart from any known issues).

The scope of work for the Cost Allocation Review includes reviewing existing cost allocation methods for ESS.

[4] Calculated by Marsden Jacob 2022.

Table 3: Proposed ESS Cost Recovery in the WEM

ESS	Risk	Service Description	Cost Allocation
Regulation Raise	Generation and load varying from target/forecast within the interval,leading to upward deviation from load forecast that causes the frequency to drop below 50 Hz.	Reserve MW to respond upwards during dispatch interval when load is greater than generation.	Allocated to Market Participants in proportion to their Regulation Contributing Quantity. The Regulation Contributing Quantity is essentially the sum of the absolute values of Metered Schedules for a Market Participant's Semi-Scheduled Facilities, Non-Scheduled Facilities and Non-Dispatchable Loads. Synergy's Notional Wholesale Meter is treated as a single Non-Dispatchable Load.
Regulation Lower	Generation and Load varying from target/forecast within the interval, leading to downward deviation from Load forecast during an interval that causes the frequency to go above 50 Hz.	Reserve MW to respond downwards when load is less than generation.	
Contingency Reserve Raise	Loss of generation.	Reserve MW to respond to loss of generation to restore frequency to an acceptable level.	Allocated using the modified runway method. Costs are allocated to Scheduled Facilities and Semi-Scheduled Facilities based on their energy, Contingency Reserve Raise and Regulation Raise in a Dispatch Interval.
Contingency Reserve Lower	Loss of load.	Reserve MW to respond to loss ofload to restore frequency to an acceptable level.	Allocated to Market Participants based on the proportion of their loads' metered consumption to total consumption per Trading Interval.
RoCoF Control Service	Rapid frequency changes can cause problems for automatic detection of frequency changes, and potentially result in damage or trip-off of generators and other system components. The RoCoF Control	The required quantity of RoCoF Control Service is a function of: • contingency size; • Contingency Reserve quantity; and • total inertia on the system.	Allocated in two parts: The Minimum RoCoF Control Requirement is shared equally (1/3 each) between: • Network Operators; • Generators (Registered Facilities with generation or storage systems); and

ESS	Risk	Service Description	Cost Allocation
	Service provides inertia.	RoCoF Control Services has two functions: • the Minimum RoCoF Control Requirement to ensure RoCoF is restricted to below a maximum limit, and • the Additional RoCoF Control Requirement, to allow trade-off between the quantity of Contingency Reserve Services required and the quantity of inertia required in the power system.	• Non-Dispatchable and Scheduled Loads. The Generator and load shares are allocated to specific Registered Facilities and loads in proportion to their Metered Schedules. The Additional RoCoF Control Requirement (to trade off with Contingency Reserve Services) is allocated to Registered Facilities using the modified runway method. Members of each group can be exempted from the Minimum RoCoF Control Requirement if they can demonstrate to AEMO that their Facility's Ride Through Capability is greater than or equal to the RoCoF Ride-Through Cost Recovery Limit.

Source: *Energy Policy WA, Scope of Work for the Review of the Allocation of Market Fees and Essential System Services Costs*

2.4.3 System Restart Services

System Restart Services (or Black Start Services) are required to allow parts of the power system to be re-energised by black start-equipped generation capacity following a full (or partial) black out. Black start-equipped generators can be started without requiring a supply of energy from the network. There is currently no market for System Restart Services as this is procured by AEMO based on a System Restart Standard. The costs of the service are recovered from Market Customers based on their metered consumption in a settlement period.

Although the efficiency of the procurement process will be assessed through further work in the locational ESS work stream (e.g., to examine locational market power concerns), the cost-recovery process for System Restart is not expected to change.

2.4.4 Non-Co-Optimised Essential System Services

NCESS costs are determined by contracts between AEMO or Western Power and other service providers. Western Power will recover the costs for its NCESS contracts via network tariffs, while AEMO will recover NCESS costs from fees levied on Market Participants based on the ratio of a loads' metered consumption to total metered consumption.

2.5 Justification for Approach

2.5.1 Frequency Regulation

Frequency regulation requirements arise because of deviations of generation and load from dispatch targets and demand forecasts respectively. A greater deviation increases the regulation requirement.

When implementing cost reflective pricing, the contribution of both generation Facilities and loads to the frequency deviation would be measured and costs allocated on the basis of the deviation. The Taskforce recommended that, while further work is to be undertaken to determine contribution factors, the cost of Regulation services will be allocated to intermittent generators and loads, based on their share of 30-minute metered generation and consumption.

2.5.2 Contingency Reserve Raise

Contingency Reserve Raise is required to cover the risk of a material decrease in power system frequency due to a generation Facility tripping or loss of network assets (excludes unexpected increase in load).

The Taskforce initially recommended adoption of the full runway method of cost allocation[5] to allocate Contingency Reserve Raise costs to generators. However, since that time, the Taskforce recommended the continued use of the modified runway method (the method currently used to allocate Spinning Reserve Costs). Under the runway method of cost allocation, the costs of contingency services would be allocated based on the degree to which a Market Participant's plant contributes to the size of the largest credible risk and therefore the overall need for contingency services. Costs will be allocated on a five-minute basis using the MW quantity of energy and frequency control ESS (Regulation and Contingency Reserve) cleared by the dispatch engine for all generation Facilities above 10MW. Changes to the runway method (apart from any known issues) are out of scope for this study, although ensuring that this method adequately reflects causer-pays principles is in scope.

The allocation of costs using the runway method is demonstrated by the following example. Say we have three generators (A=100 MW, B=100 MW and C=150 MW). Using the runway method, all three generators would pay for Contingency Reserve Raise for the first two thirds of contingency costs, while generator C would pay for all the last third of Contingency Reserve costs. This would mean that A and B pay 22.2% each (one third of two thirds) and C pays 55.6% and shows that the largest generator pays the large proportion of Contingency Reserve costs and smaller generators pay less. The rationale for this, is that larger generators increase the requirements for Contingency Reserve compared to smaller generators.

While the runaway method allocates more of the costs to the largest generator, it could be argued that the largest generator that is operating in a Trading Interval should pay for all of the costs in that Trading Interval since it is setting the requirement for Contingency Reserve in that period.

There are potential efficiency gains from using the runway method for allocating Contingency Reserve Raise costs. As the largest generator is incurring higher Contingency Reserve costs ($/MW) at higher output levels, it may reflect this in higher Balancing Market bids for higher output

5 Energy Transformation Taskforce, Market settlement, Implementation of five-minute settlement, uplift payments and Essential System Services settlement, 1 December 2019, p.14.

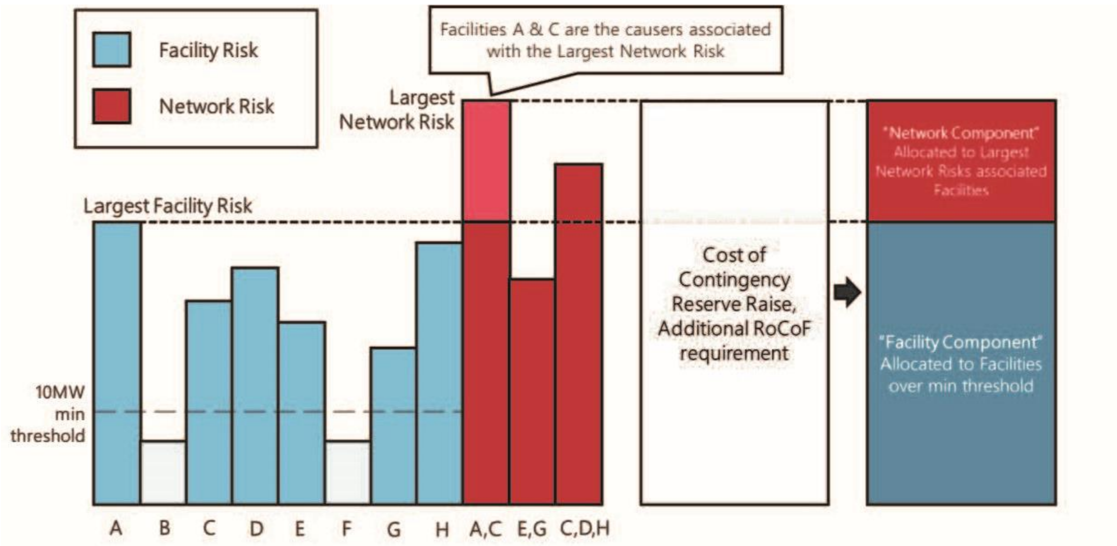
quantities. As a result, an efficient market outcome would be for small generators to be dispatched at higher output levels than using a larger generator, since Contingency Reserve quantities can be lower, which could reduce overall market costs.

The modified runway allocation method is used to allocate the costs per Dispatch Interval of procuring both Contingency Reserve Raise and the additional RoCoF requirement of the Rate of Change of Frequency Control Service (RCS). RoCoF is effectively a substitute for Contingency Reserve Raise and can be used to meet the Contingency Reserve Raise Requirement in each Dispatch Interval, so its costs can be recovered on the same basis.

Under the modified runway method, contingent events that need to be managed include the outage of Facilities (storage or generation) and network assets. For network risks, the runway method is applied to all energy producing Facilities that would be disconnected because of a network outage (that is, the relevant lines disconnecting). The magnitude of the network component reflects the delta between the Largest Network Risk and the Largest Facility Risk (see Figure 1).

In summary, the runway method attempts to allocate Contingency Reserve costs to causers of contingencies (application of causer-pays principle) and the extent to which they have contributed to the requirement for Contingency Reserve Raise services. This cost allocation has the potential to increase the efficiency of the wholesale market if dispatch outcomes (i.e., dispatching smaller units) reduce overall wholesale costs (i.e., sum of Contingency Reserve and energy costs).

Figure 1: Allocation of Contingency Reserve Raise and RoCoF requirement costs to a Facility based on Facility and Network Risks



Source: AEMO, WEM Reform: Wholesale Electricity Market Design Summary, A report describing the Wholesale Electricity Market in the South West Interconnected System, May 2021, p.91.

2.5.3 Contingency Reserve Lower

Contingency Reserve Lower is required to cover the risk of a material decrease in system frequency due to a loss of load. Therefore, loads are the causer of a Contingency Reserve Lower requirement.

Contingency Reserve Lower costs will be recovered from loads based on their share of consumption in the Trading Interval. This is consistent with the current cost allocation method for Load Rejection Reserve.

From 1 October 2022 to 30 September 2025, Contingency Reserve Lower costs will be allocated on a 30-minute basis, based on the load's 30-minute metered consumption quantity.

Cost allocation on a five-minute basis is relatively more difficult to implement due to the absence of five-minute metering for loads. A methodology to profile 30-minute consumption quantities using SCADA data (where available) to five-minute load volumes, would need to be developed. This may involve complex implementation and SCADA equipment may not be available at all load sites. For these reasons, costs will be allocated to loads on a 30-minute basis until five-minute meters and five-minute settlement is implemented.

2.5.4 Rate of Change of Frequency Control

RoCoF Control is a new ESS that performs the following two functions:

- primarily, to restrict the RoCoF to below a certain level (minimum RoCoF requirement); and
- secondarily, as a substitute for Contingency Reserve Raise (the more inertia there is in the power system at any given point in time, the less Contingency Reserve Raise is required) – there is a trade-off between the two services – the amount of RoCoF Control service scheduled to meet this requirement is referred to as the additional RoCoF requirement.

This new service is required because, as the amount of synchronous generation on the power system reduces, the expected RoCoF when a Contingency Event occurs will increase. This can result in cascading trips for generators and potential damage to generating units and under-frequency load shedding if this is not addressed.

The RoCoF Control service, by its nature, requires (higher marginal-cost) synchronous generators to run instead of cheaper intermittent renewable generators (constrained down).

Generation and network Facilities are important drivers for the requirement for RoCoF Control services. To incentivise generators and network Facilities to improve their ride-through capability and reduce their exposure to the costs of the RoCoF Control service, it is reasonable to allocate a proportion of the costs to them. Large industrial and commercial loads can also benefit from improved ride-through capability, so it makes sense to allocate RoCoF costs to them as well.

If generators, network Facilities and large-customers are all incentivised to improve ride-through capability, then smaller loads (i.e., residential, and small and medium businesses) may ultimately become the only remaining reason for the service. Given that they will ultimately be the beneficiary of the service, it could be argued that they should bear some of the cost of the service.

Therefore, generators, loads and Western Power will all bear a share of RoCoF charges (1/3 each). While 30-minute settlement is in place between 1 October 2022 and 30 September 2025, the generator and load share of the Minimum RoCoF Control Requirement will be allocated based on 30-minute metered generation and consumption values. Once five-minute settlement is implemented, cost recovery will occur on a five-minute basis.

The method for RoCoF cost recovery method is out of scope for this review.

2.6 Proposed Reforms

The WEM is currently going through a significant period of change to deliver secure, reliable, and affordable electricity, while facilitating the penetration of zero or low emission generation technologies to achieve Commonwealth and the Western Australian Government's decarbonisation targets. Addressing both market and technical requirements to support a high penetration of both small-scale and large-scale renewable energy Facilities with less dispatchable plant (i.e., coal and gas) available to the system operator to manage demand and supply imbalances in real time, or provide other services (such as inertia, reactive energy, voltage support) will be important to ensure supply reliability can be maintained in the future.

EPWA, AEMO and Market Participants are involved in a range of trials, reviews of WEM Rules and WEM Rule changes to ensure that a reliable power system can continue. This includes:

- introduction of a market for ESS;
- implementation of a security constrained economic dispatch (SCED) that is co-optimised across energy and ESS;
- implementation of five-minute dispatch intervals and five-minute market settlement in 2025;
- providing for participation of Electric Storage Resources (ESR) in the WEM;
- new generator performance monitoring and compliance standards;
- development of Whole of System Plans (WOSPs) to ensure adequate planning for future development of WEM markets and to provide incentives for investors/participants to invest in needed technologies to enable the WEM to meet future requirements (i.e., flexible generation and storage); and
- integration of DER into the WEM.

3. National Energy Market

3.1 Spot Market

The NEM is a gross pool in which physical delivery of all electricity is managed through the spot market. Generators offer to supply the market at specified prices (offers) and the market price in each Trading Interval (5 minutes) is determined by the most expensive unit cleared to meet demand in that Trading Interval.

The spot market is subject to a Maximum Price Cap (MPC) of $15,100/MWh and a market floor price of negative $1,000/MWh. Because of the risks associated with price volatility in the NEM, financial contracts (external to spot market) are used to trade most of the electricity transacted in the spot market. These arrangements are generally in the form of derivatives, and include swaps or hedges, options and futures contracts.

Formal participants in the spot market include Market Generators and Market Customers (retailers).

There are over 504 registered participants in the NEM, including Market Generators, transmission network service providers, distribution network service providers, and Market Customers.

AEMO is the wholesale market operator (i.e., operates the spot market), system operator (dispatches plant and the operation of networks to maintain power system reliability) and last resort supplier (secures energy supplies through the Reliability and Emergency Reserve Trading (RERT) scheme). AEMO also operates the retail electricity markets across the NEM.

3.2 Reliability

Reliability refers to the power system being able to supply enough electricity to meet customers' requirements. The current standard in the NEM is that any shortfall in power supply should not exceed 0.002% of total electricity requirements. The MPC of $15,100/MWh has provided sufficient incentive for Market Participants to invest in enough generation to minimise the occurrence of MPC events, which in turn implies that there is sufficient generation to avoid unserved energy (USE) exceeding 0.002%. The MPC has rarely been breached, but AEMO has been increasingly intervening in the market to manage forecast supply shortfalls.

The Commonwealth Government became concerned that the high MPC was not sufficient to maintain reliability and launched the Retailer Reliability Obligation (RRO) scheme in 2019 to ensure that retailers and large customers, would purchase contracts to support investment in dispatchable electricity generation in regions where a gap between generation and peak demand (1 in 10 year event) is forecast (3 years ahead). If triggered, retailers and large energy users are then required to secure additional contracts with dispatchable generation sources.

In November 2020, the Energy Security Board (ESB) reduced the trigger for activating the RRO (to a forecast of 0.0006% USE). The scheme was activated in 2020 for a potential shortfall in NSW in 2023-24.

3.2.1 NEM Ancillary Services

To maintain power system security[6], the NEM has established three categories of Ancillary Services;

- Frequency Control Ancillary Services (FCAS);
- Network Support and Control Ancillary Services (NSCAS); and
- System Restart Ancillary Services (SRAS).

Only FCAS is traded in formal markets, whereas NSCAS and SRAS are non-market Ancillary Services that are procured under contracting arrangements.

3.2.2 Frequency Control Ancillary Services

Frequency Control Ancillary Services (FCAS) is used to maintain the frequency of the electrical system (close to 50 Hz) and includes:

- Regulation – Regulation frequency control (both Lower and Raise services) are used to correct minor deviations which can arise due to inaccuracy of load or generation forecasts; and
- Contingency - Contingency frequency control (both Lower and Raise) is used to correct deviations in frequency following a major Contingency Event such as the loss of a generating unit/major industrial load, or a large transmission element. There are 6 contingency frequency control services based on the Lower and Raise service and response times (6 second, 60 seconds, 5 minutes).

AEMO ensures that sufficient FCAS are procured at any given time (across 8 markets). Participants must register with AEMO to participate in each distinct FCAS market. Once registered, a service provider can participate in an FCAS market by submitting an appropriate FCAS offer or bid for that service, via AEMO's Market Management Systems.

The size of the FCAS markets are substantially lower than the spot energy market. For example, the total size of the FCAS market in the NEM is around 600 MW, compared to installed capacity in the NEM of over 60,000 MW (1% of the size). As a result, there are substantially fewer participants operating in FCAS markets than in the wholesale electricity market. In early 2021, there were 10 FCAS providers in Queensland, NSW and South Australia, 8 in Victoria, and 2 in Tasmania. Demand response aggregators now offer FCAS across all NEM regions; virtual power plants offer services in all mainland regions; and battery storage offers services in South Australia, having displaced many fossil fuel generators providing that service in that state.

3.2.3 Network Support and Control Services

Network Support and Control Ancillary Services (NSCAS) are used to control voltages and power flow across network elements and maintain transient and oscillatory stability within the power system following major power system events. NSCAS is provided to the market under long term ancillary service contracts negotiated between AEMO (on behalf of the market) and the participant providing the service.

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6 Power system security relates to maintaining the power system within technical operating limits needed to keep it safe and stable. Parameters of system security include frequency and voltage stability; and physical properties such as system strength and inertia.

3.2.4 System Restart Ancillary Service

System Restart Ancillary Service (SRAS) are reserved for contingency situations in which there has been a complete or partial system blackout and the electrical system must be restarted. This can be provided by a generator that can start and supply energy to the transmission grid without any external source of supply. SRAS is also provided to the market under long term ancillary service contracts negotiated between AEMO (on behalf of the market) and the participant providing the service.

3.3 Fee Recovery for Market Services and Ancillary Services

3.3.1 AEMO Services

In the NEM, fees are payable for various services provided by AEMO, such as power system security and reliability, market operations and systems, wholesale metering, settlements and prudential supervision, and longer-term energy forecasting and planning services. Fees are levied on Market Customers based on customer load ($/MWh), while fees are levied on Market Participants[7] based on both capacity and energy for a previous 12 month period. In terms of the NEM Revenue Requirement, 67% of costs are recovered from Market Customers, while 33% if recovered from Market Participants.

Table 4: NEM Market Fees and Budget (2021/22)

Function	Budget 2020/21 ($0000)	Role	Paying Participant
General Fees (unallocated)	31,040	$0.17700/MWh of customer load	Market Customers
Allocated Fees			
Market Customers	39,110	$0.22302/MWh of customer load	Market Customers
Wholesale Participants	33,316		Wholesale Participants
NEM Revenue Requirement	103,466		
Participant Compensation Fund	1,000	Daily rate calculated on 2020 capacity/energy basis	Scheduled Generators, Semi-Scheduled Generators and Schedule NSPs

7 Includes Market Generators, Managed Network Service Provider (MNSP), Small Generation Aggregators (SGAs), Market Ancillary Services Provider (MASP), and Demand Response Service Provider (DRSP)s

Function	Budget 2020/21 ($0000)	Role	Paying Participant
Registration Fees	2,700		Participants that intend to register
Other	18,217		Dependent on service provided
Project Developer		$6,365/assessment/Facility	Project developers
NEMDE queue		$15,540/application	Registered Participants
Total NEM	125,383		

Source: *AEMO Electricity Revenue Requirement and Fee Schedule 2021-22*

AEMO also charges Application Fees and Reassessment Fees, which are set to recover the average costs of processing each type of application.

AEMO undertook a comprehensive review of fee structures in 2020/21 in part due to the need, to accommodate new technologies and new participants that were not being charged in the current fee structure. Many issues concerning user- versus beneficiary-pays principles were raised in this review, including:[8]

- with declining operational consumption in many NEM regions, charging based on $/MWh may no longer be an appropriate cost allocation driver. While most stakeholders supported the existing charging mechanism of $/MWh, others supported a change to per connection point (or $/NMI) charge or a combination of both variable and fixed rates;
- some participants wanted to extend NEM fee recovery to Network Service Provider (NSPs); and
- recovery of major transformational initiatives undertaken by AEMO (e.g., Five Minute Market Settlement, DER integration, Energy Consumer Data Rights, etc.) could be based on recovery from either Market Customers only, DER resources (based on beneficiary-pays principle), and/or existing Market Participants.

The future changes to the fee structure are intended ensure all beneficiaries contribute to future costs, included:[9]

- changes implemented 1 July 2021 to 30 June 2023 included:
  - SGAs and MASPs/DRSPs will now be included in the Generators/MNSP allocation and charged in a similar manner (refer to all as “Wholesale Participants”);[10] and
  - removal of the division of costs between Non-market generators/MNSPs and Market generators/MNSPs.

8 AEMO, Electricity Fee Structures, Draft Report and Determination, A draft report and determination on electricity fee structures to apply to Participant fees from 1 July 2021, November 2020

9 AEMO, Electricity Fee Structures, Final Report and Determination, A final report and determination on electricity fee structures to apply to Participant fees from 1 July 2021, March 2021, pp.11.

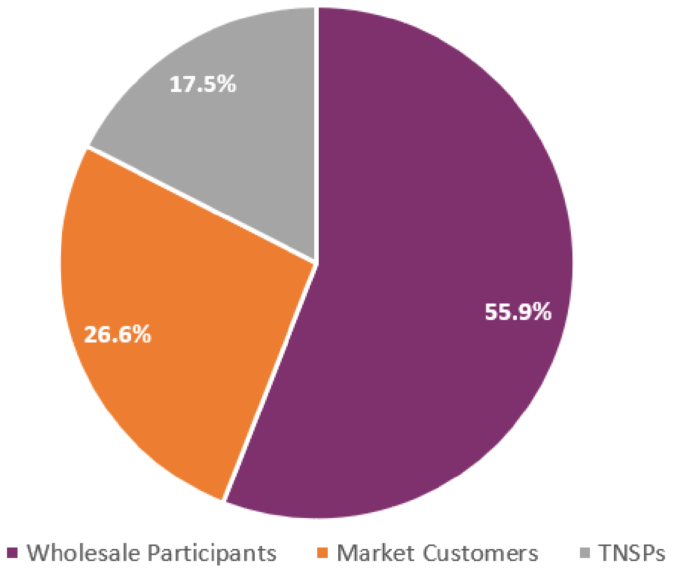
10 SGAs, MASPs/DRSPs, Generators (excluding Non-Scheduled Non-Market Generators) and MNSPs are collectively referred to as “Wholesale Participants”.

- From 1 July 2023 to 30 June 2026, the following changes will be made:
  - Wholesale Participants to be allocated 55.9% of direct costs, charged on a similar basis to the existing structure;
  - Market Customers to be allocated 26.6% of direct costs, charged a combination of $/MWh and $/NMI on a 50/50 basis. All indirect costs are charged to Market Customers; and
  - TNSPs to be allocated 17.5% of direct costs, charged on a basis of energy consumed for the latest completed financial year.

Costs are allocated directly to relevant participants for transformation initiatives, where reasonably practicable.

As a result of these changes, Wholesale Participants will bear most of AEMO direct costs, followed by Market Customers and then TNSPs, as shown in Figure 2.

Figure 2: NEM Fee Direct Cost Allocation by User Class



Source: *AEMO, Electricity Fee Structures, Final Report and Determination, A final report and determination on electricity fee structures to apply to Participant fees from 1 July 2021, March 2021, pp.12.*

3.3.2 Frequency Control

Costs for regulation services are recovered from participants that contribute to frequency deviations under a causer-pays methodology. Costs for Raise contingency services are recovered from generators; and costs for Lower services are recovered from Market Customers (usually retailers).

Table 5: FCAS Cost Recovery by Service

FCAS Type	Service	Description
Regulation	Regulation **Raise**	FCAS Regulation services (both Raise and Lower) are caused by unexpected (but relatively small deviations) between actual

FCAS Type	Service	Description
	Regulation **Lower**	demand and supply and forecasts, so the costs are recovered from all Wholesale Participants using the 'Causer-Pays' methodology. This includes recovery of costs from: 1. Scheduled and Semi-Scheduled Generators; 2. Scheduled loads (i.e., pumping/charging for storage); and 3. Wholesale Market Customers.
Contingency Raise	**5 minute** **60 seconds** **6 seconds**	Loss of supply is the most likely cause of the need for Raise Contingency services, so the costs of enabling FCAS Contingency Raise Services are **recovered from all generators** – or, more accurately from: 1. Scheduled Generators; and 2. Semi-Scheduled Generators. This excludes Non-Scheduled Generators and smaller generators connected to distribution systems or behind the meter.
Contingency Lower	**6 seconds** **60 seconds** **5 minute**	Sudden drops in consumption (e.g., trip of a large load) are the most likely cause of the need for Lower Contingency services, so the costs of enabling FCAS Contingency Lower Services are recovered from all loads – i.e., those seen by the AEMO in the wholesale market. This includes: 1. Wholesale Market Customers, which includes retailers and large loads; and 2. Scheduled loads (i.e., pumping/charging for storage).

Source: Adapted from https://wattclarity.com.au/other-resources/explanations/glossary/fcas/

NSCAS costs are recovered from Market Customers in proportion to their energy consumption in the relevant Requirement region.

SRAS costs are recovered from Market Customers (50%) and collectively from Market Generators and Market Small Generation Aggregators (50%) on a regional basis. The relevant SRAS payments are recovered in proportion to the energy consumption/generation of each relevant Market Participant within the respective benefiting region.

3.4 Allocation of Fees and Charges

NEM fees are around 0.3% of the annual residential bill for a NEM customer.[11]

FCAS costs have been relatively low in relation to energy costs in the past. In 2015 FCAS costs totalled $63 million, which represented around 0.7% of NEM energy costs. However, these costs increased steadily and by 2020 FCAS costs totalled around $356 million, mainly due to higher costs associated with islanding in South Australia and network outages caused by bushfires.[12]

11 Calculated by Marsden Jacob 2022.

12 Australian Energy Regulatory, State of the Energy Market 2021, p.112.

However, FCAS prices are likely to reduce in the future with the likely entry of storage Facilities required to firm intermittent generation sources (effectively an increase in the number of suppliers of FCAS).

3.5 Justification for Approach

3.5.1 NEM Fee Allocation

Based on a cost allocation study undertaken by AEMO, 70% of costs are attributable to key NEM outputs, while 30% are non-attributable. Based on AEMO activities and interactions with participant classes, it was found that more activities related to market aggregators and large generator classes, as well as TNSPs, compared to Market Customers.[13] Hence the increase in fees allocated to market aggregators, Wholesale Participants and application of charges to TNSPs (see Section 3.3.1).

All of the non-attributable costs are to be allocated to Market Customers, who will pass these costs onto final customers, given that there is no benefit in applying these charges to other users or participants.

3.5.2 Market Customer Fee

While the bill determinants did not change for Wholesale Participants (i.e., 50% based on capacity/50% based on MWh energy), Market Customers, who are currently billed on the basis of MWh energy, will be billed on 50% of MWh energy and 50% on the number of connections (or NMIs) from 1 July 2023, for both unattributable and attributable costs.

To overcome some of the shortfalls associated with billing on a net metered energy basis, AEMO considered billing on a gross metered basis to reduce the existing cross-subsidy from final customers that rely on grid power to those that have installed DER. AEMO rejected this approach because it took the view that charging users on a unit cost basis still encourages customers to reduce consumption, which is inefficient given that AEMO's costs are fixed.[14]

It appears to be a pragmatic solution based on AEMO's justification for the billing split between number of connections and MWh:[15]

> *"…neither NMI nor MWh are perfect metrics upon which to charge participants (and their consumers) therefore, on balance, a combined fixed and a variable fee demonstrates greater consistency with the fee structure principles, has regard to the NEO, and AEMO is more readily able to implement the $/MWh and $/NMI charge as they are fees that AEMO already implements in the fee structure."*

Based on economic principles, it is likely that a less distortionary charge would be to charge all users on the basis that they have an electricity connection to the grid, and hence their indirect use of NEM services. Applying all charges on the basis of connection points runs the risk that customers may try to disconnect from the grid and rely on standalone power systems (e.g., solar and battery systems with diesel backup). However, the costs of standalone power systems in

13 AEMO, Electricity Fee Structures, Final Report and Determination, A final report and determination on electricity fee structures to apply to Participant fees from 1 July 2021, March 2021, pp.14.

14 Ibid, p.15.

15 Ibid, p.16.

major metropolitan areas is unlikely to be economic at the current time, although it could be economic for customers in remote areas of Australia that are faced with cost reflective tariffs.

3.5.3 Charging Network Service Providers

While AEMO rejected charging DNSPs because of their lower level of involvement with this user class, they agreed to charge TNSPs because of a higher level of involvement with this user class. Ultimately, this cost will be passed through to final customers via regulated network charges and they will include a margin on those costs.

There appears to be little justification for levying this charge on TNSP’s and it is likely to be more efficient (no double handling of fees) to simply allocate these costs to Market Customers (and hence final customers).

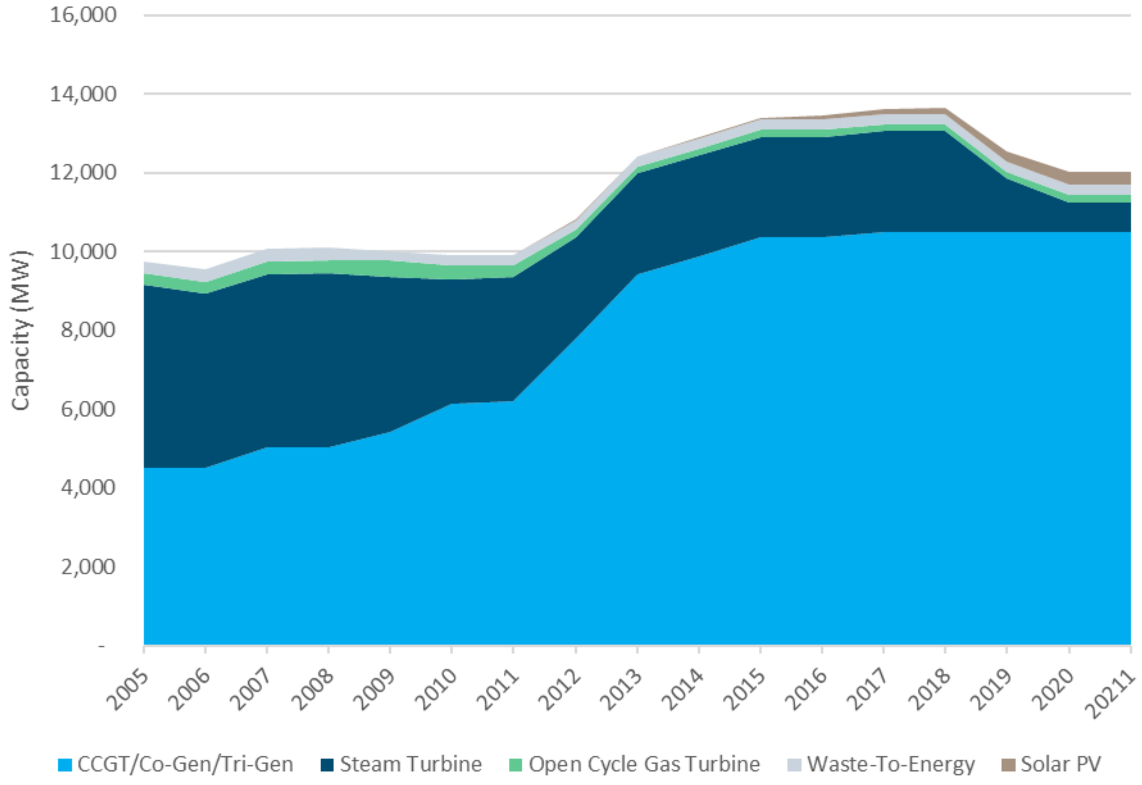
4. National Electricity Market of Singapore

4.1 Market Design and Market Mechanisms

The Energy Market Authority (EMA) is the Power System Operator (PSO) responsible for the supply of electricity to consumers and the operation of the power system in Singapore, as well as regulating the market and developing the industry. Peak demand in the grid was 7,562 MW in May 2021, with a total registered generation capacity of 12,033 MW[16]. Most of the installed capacity is from gas turbines and co/tri-generation plants (88.7%), followed by steam turbines (6.3%), solar (2.8%) and waste-to-energy (2.1%).

The changing mix of electricity generation capacity by fuel type is shown in Figure 3. The total registered generation capacity has fallen since 2015, primarily through a large reduction of steam turbine generation capacity.

Figure 3: Electricity Generation Capacity by Technology type, 2005 - 2021



Source: Singapore Energy Statistics 2021

The Energy Market Company (EMC), part owned by EMA, operates and administers the wholesale market, the National Electricity Market of Singapore (NEMS). The NEMS' role includes calculating prices, scheduling generation, clearing and settling market transactions and procuring Ancillary Services on behalf of the PSO.

16 Singapore Energy Statistics 2021

4.1.1 Ancillary Services

EMC procures Ancillary Services through Ancillary Service Contracts (ASCs) and a real-time market. Services provided through contracts include reactive support and voltage control, black start, fast start, reliability must-run. EMC pays the ancillary Service Provider (ASP) for the provision of the services in accordance with the ASC and recovers the cost incurred through the wholesale market by collection of a Monthly Energy Uplift Charge (MEUC) from Load Serving Entities (LSEs) in each dispatch period.

Under the new Financing Framework for Procurement of Ancillary Services (2020)[17], EMC will finance all new CAPEX required for the provision of Ancillary Services that meet certain criteria. The ASP can therefore only recover costs associated with OPEX, depreciation of existing fixed assets and a capped profit margin of 10%. The new CAPEX and other associated financing costs will be recovered through the MEUC.

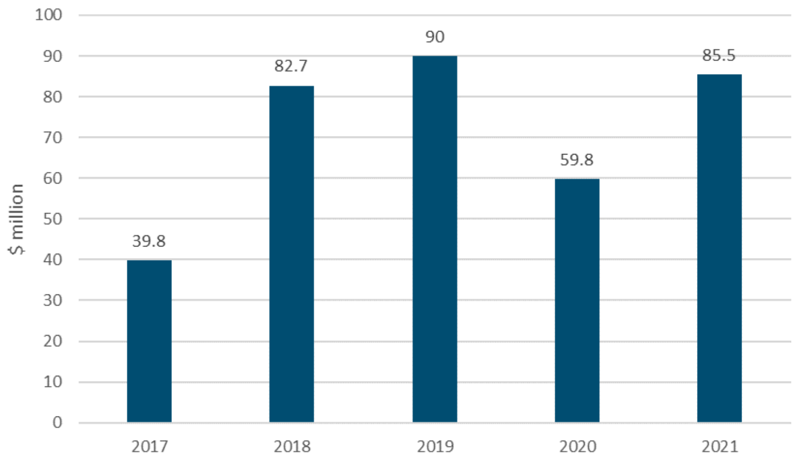
Services provided through the real-time market include regulation and reserve services. The PSO determines the amount of regulation and reserve services required for each dispatch period.

Facilities can be available for energy supply and reserve/regulation, which requires the market clearing engine (MCE) to consider the trade-off between reserve, regulation and energy supply offers. The MCE optimises the supply based on the lowest cost solution (in terms of offers made), considering the minimum generation level of Facilities. Generators can only put in a reserve offer if they have a corresponding energy offer.

4.1.2 Reserve

The cost of reserve is recovered from generators during settlement. The total reserve payment increased 43% from 2020 to 2021, primarily driven by an increase in the Contingency Reserve prices from $4.52/MWh to $14.43/MWh and an increase in the Contingency Reserve requirements from 596 MWh to 605 MWh (see Figure 4).

Figure 4: Annual Reserve Payment 2017-2021 ($SGD)



Source: NEMS Market Report 2021[18]

[17] https://www.emcsg.com/f424,149383/Financing_Framework_for_Procurement_of_Ancillary_Services_-_Information_Paper_21_Sep_2020.pdf

[18] https://www.emcsg.com/f279,163100/NEMS_Market_Report_2021_FINAL.pdf

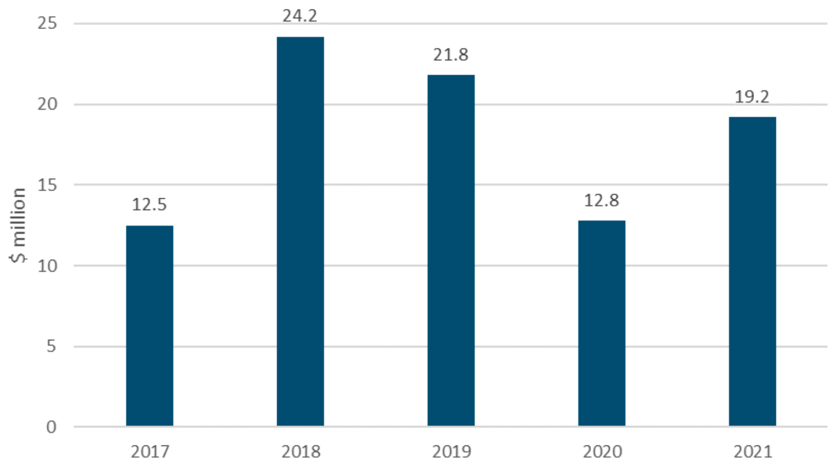
The primary reserve has a response time of nine seconds. Primary reserve prices in the calendar year 2021 were highest in September ($2.68/MWh) and lowest in April ($0.42/MWh). The primary reserve requirement ranged from 164MW to 183 MW/month with the lowest levels in March and highest in September. During this period there were no periods with intertie disconnections and primary reserve shortfalls in 2021. The primary reserve was previously split into primary and secondary but are now split into five groups based on reliability.

The Contingency Reserve has a response time of 10 minutes. Contingency reserve prices were highest in December ($26.85MWh) and lowest in June ($6.09 MWh). The annual average Contingency Reserve offers increased 5.8% and the proportion of offers below $5/MWh fell from 57.5% in 2020 to 51.5% in 2021. The high prices in December were largely due to the number of periods with a Contingency Reserve shortfall. Nineteen (19) of the 63 Contingency Reserve shortfall periods occurred in December of 2021.

4.1.3 Regulation

Regulation payments increased by 50% in 2021, in line with a 71% increase in the regulation price to $16.45/MWh (Figure 5). There is a large amount of volatility in regulation prices, with a spread of $28.41 and a standard deviation increase from $4.77MWh in 2020 to $9.70/MWh in 2021. While there were more periods of regulation shortfall in 2021, the periods were narrower than in 2020.

Figure 5: Annual Regulation Payment 2017-2021 ($SGD)



Source: NEMS Market Report 2021[19]

4.2 Fee Recovery for Market Services and ESS

The costs associated with the wholesale functions of the NEMS are recovered directly from the wholesale market through fixed and variable fees proportionate to the quantity of energy the Market Participant's trade. These fees are in addition to the provision of Ancillary Services discussed above.

[19] https://www.emcsg.com/f279,163100/NEMS_Market_Report_2021_FINAL.pdf

Table 6: Fee Recovery for Market Services

EMC Fees – 1 July 2021 to 30 June 2022	
Market Participant (MP) Fee	10,000/MP (annual)
MP Registration Fee	$5,000/registration (one-off)
RSA Hardware Token Fee	$350/token (once every 3 years from 6th token onwards per MP) $110/token (replacement fee for lost or damaged token)
EMS Fee per MWh ($/MWh)	0.3491
PSO Fixed Fees – 1 July 2021 to 30 June 2022	
MP Fee	$3,500/MP (annual)
MP Registration Fee	$1,650/legal entity registration (one-off)
PSO Net Fees – 1 April 2021 to 31 March 2022	
PSO Net Fees ($000)	25,171

Source: NEMS Market Report 2021[20]

Fee recovery for reserve is calculated using a variant of the "runway" model which calculates the allocation of cost to each dispatchable Facility. Costs are weighed more heavily to larger Facilities, rather than those with a poor reliability history.

The cost of regulation is recovered from load and the first 10 MW of each generating Facility being dispatched. This is based on a causer-pays model whereby load and generation are creating the need for regulation services.

4.3 Proposed Reforms

The NEMS operates as an Energy-Only Market meaning that generators are only paid for when they provide power on a day-to-day basis.

Since 2019, EMA has held talks with key stakeholders in the industry regarding the introduction of a forward capacity market. Despite the benefits of ensuring a reliable future electricity supply in the future, key decision makers believe that this will come at a cost to consumers, who may end up paying for generation that may never be called upon to provide power.

The NEMS is regarded as having one of the most reliable supplies of electricity in the world with average interruption times of less than a minute per customer annually.[21]

The NEMS established the Interruptible Load Scheme in 2004, which aims to ensure the secure supply of electricity by supplementing existing reserves from generators.[22] This involves calling

20 https://www.emcsg.com/f279,163100/NEMS_Market_Report_2021_FINAL.pdf

21 Energy Market Authority 2020, Co-Creation with Industry: Fast Service Survey and Feedback, www.ema.gov.sg/cmsmedia/PPD/Fast%20Start%20Service%20Feedback%20and%20Survey.pdf

22 Energy Market Company 2019, A Guide to Providing Interruptible Load in Singapore's Wholesale Electricity Market, www.emcsg.com/f146,16653/Guide_to_providing_IL_website_20191104.pdf

upon consumers with interruptible load to reduce consumption in the event scheduled reserves were insufficient to restore demand and supply imbalances.

The introduction of the scheme has benefited customers in the long run by:

- securing the supply of energy by supplementing existing reserves from generators;
- increased competition in providing reserve services, putting downward pressure on prices for these services;
- allowing generators to use this generation capacity outside of providing reserve services, which will put downward pressure on energy prices; and
- decrease volatility of prices by increasing the liquidity of reserve sources.

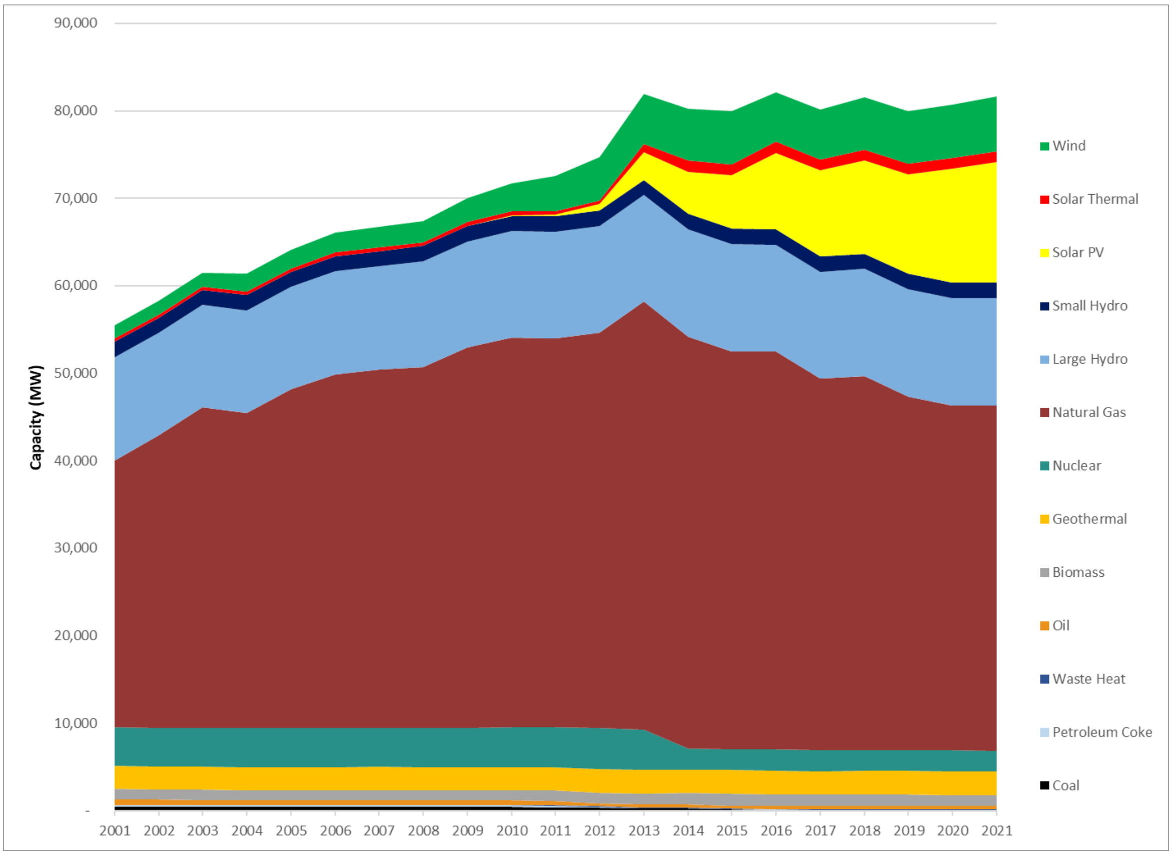
5. California Independent System Operator

5.1 Market Design and Market Mechanisms

The California Independent System Operator (CAISO) runs the power grid covering the state of California and a small part of Nevada (32 million customers).[23] Peak demand in the grid was 42,844 MW in 2021 (highest demand of 50,270 MW occurred in 2006)[24], with installed generating capacity of 66,000 MW.[25] Most installed capacity is gas plant (47%), followed by solar (20.9%), hydro (15.2%) and wind (8.9%).[26]

The changing mix of generation in California is shown in Figure 6 (includes ISO and non-ISO participating capacity) by fuel type.

Figure 6: Installed in State (California) Electricity Generation Capacity by Fuel Type



Source: https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/electric-generation-capacity-and-energy

CAISO also operates California's wholesale electricity market, which includes energy (day-ahead and real-time), Ancillary Services, and congestion revenue rights. CAISO also operates an Energy

23 California ISO, Key-Statistics-Aug-2021

24 Ibid.

25 Department of Market Monitoring - California ISO, 2020 Annual Report on Market Issues & Performance, August 2021, p.17.

26 Ibid.

Imbalance Market (EIM), which currently includes CAISO and other balancing authority areas in the western United States. [27]

The wholesale market is 'energy-only' and utilises a full network model to generate locational marginal prices (LMP) every 5 minutes for 9700 individual nodes across the network.[28] Some of the mechanisms operated by CAISO include:[29]

- the day-ahead market opens for bids and schedules seven days before and closes the day prior to the trade date. Day ahead results are published at 1:00 pm the day before the trade date;
- the real-time energy market opens when the day-ahead market results are published and permits participants to buy and sell power to meet the last few increments of demand not covered in day ahead schedules. The real-time energy market also secures energy reserves, held ready and available for ISO to use if needed, and the energy needed to regulate transmission line stability;
- the market opens at 1:00 p.m. prior to the trading day and closes 75 minutes before the start of the trading hour. The results are published about 45 minutes prior to the start of the trading hour. The real-time market system dispatches power plants every 15 and 5 minutes, although under certain grid conditions; the ISO can dispatch for a single 1-minute interval;
- congestion revenue rights (CRRs) are financial instruments used to offset congestion costs that occur in the day-ahead market process. CRRs are made available through allocation, auction and bi-lateral trade and are settled based on the marginal cost of congestion. A revenue rights obligation pays its holder when congestion is in the same direction as the obligation, and charges the holder if congestion is in the opposite direction. The reverse is true for CRR options;
- there are four types of Ancillary Services products: regulation up and down, spinning and non-spinning reserve:
    - Regulation (Up and Down) service are used to control system frequency (i.e., ~60 hertz). Resources providing regulation are certified by CAISO and must respond to automatic control signals to increase or decrease their operating levels depending upon the need;
    - Spinning reserve is standby capacity from generation units already connected or synchronized to the grid and that can deliver their energy in 10 minutes when dispatched; and
    - Non-spinning reserve is capacity that can be synchronized to the grid and ramped to a specified load within 10 minutes.

Energy and Ancillary Services are co-optimised in the day ahead and real-time energy markets.

27 https://www.ferc.gov/electric-power-markets

28 California ISO-General Company Brochure

29 http://www.caiso.com/market/Pages/MarketProcesses.aspx

5.1.1 Ancillary Services in California

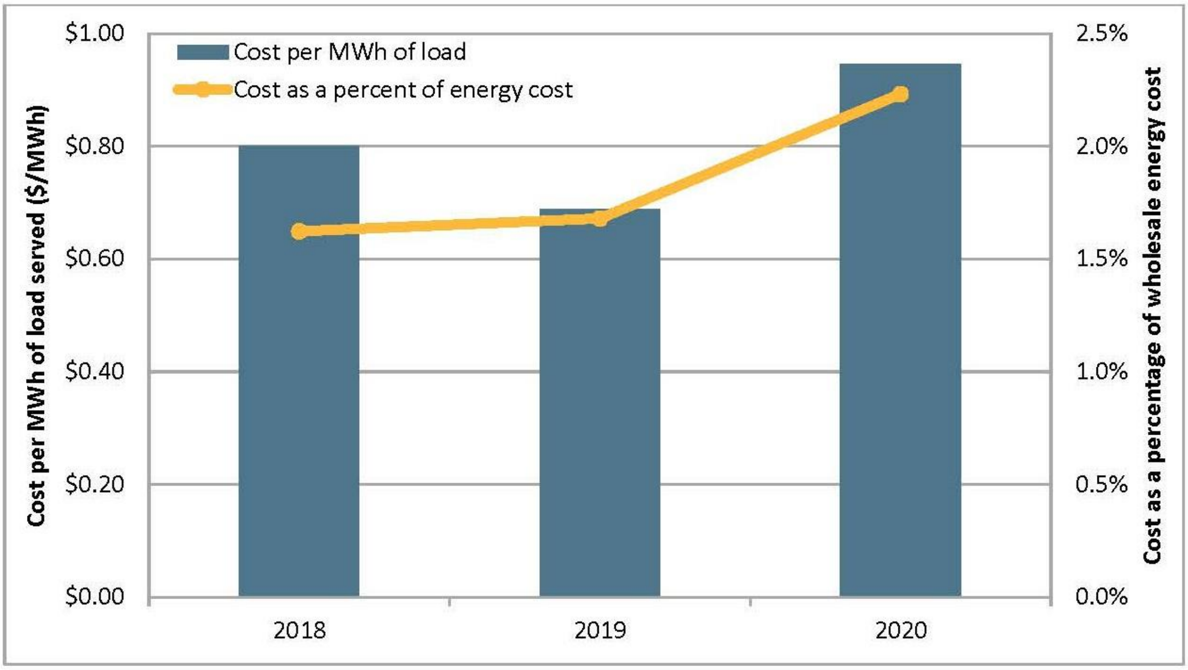
Ancillary service costs increased from $0.69/MWh to $0.95/MWh in 2019, and from 1.68% to 2.23% of total wholesale energy cost, as shown in Figure 7.Figure 7: CAOSP Ancillary Service Costs as Percentage of Energy Costs

Total ancillary service costs increased to $199 million, up from $148 million in 2019, and $177 million in 2018. Increased costs were driven primarily by higher requirements and higher prices in the third and fourth quarter of 2020.[30]

Regulation down requirements increased 22% to 520 MW and regulation up requirements increased 12% to 390 MW, relative to 2019. Average combined requirements for spinning and non-spinning operating reserves also increased by 12% from the previous year to about 1,800 MW.

The frequency of ancillary service scarcity intervals decreased, remaining low. There were 129 intervals in the 15-minute market with ancillary service scarcity, compared to almost 200 scarcity instances in the previous year. The number of regulation scarcities decreased substantially. However, the number of non-spin scarcities increased from 2019 to 2020, particularly in August and September, when the ISO faced very tight conditions.

Figure 7: CAOSP Ancillary Service Costs as Percentage of Energy Costs



Source: Department of Market Monitoring - California ISO, 2020 Annual Report on Market Issues & Performance, August 2021, p.9.

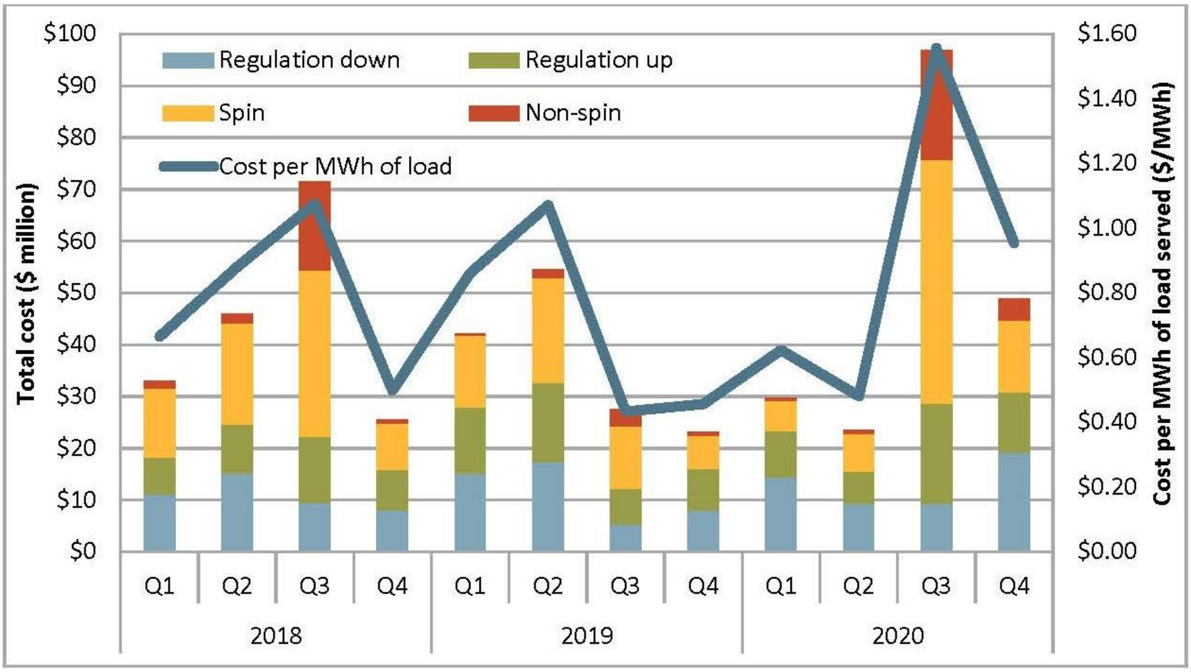
Figure 8 shows the total cost of producing ancillary service products by quarter and the total ancillary service cost for each megawatt-hour of load served.

Payments increased for both regulation and operating reserves from 2019 to 2020, however the increase in operating reserves was much more pronounced. While payments for regulation up and down increased 10% to $98 million, payments for spinning and non-spinning reserves increased

30 Department of Market Monitoring - California ISO, 2020 Annual Report on Market Issues & Performance, August 2021, p.8.

70% to over $100 million. This increase was due in large part by the increase in payments for spinning reserves which increased from $6 million in 2019 to over $46 million in 2020. Even non-spinning reserves increased from <$1M to $21M.

Figure 8: CAISO Ancillary Service Costs by Type



Source: Department of Market Monitoring - California ISO, 2020 Annual Report on Market Issues & Performance, August 2021, p.161.

5.1.2 Operating Reserve Requirements

Operating reserve requirements in the day-ahead market are typically set by the maximum of three factors: [31]

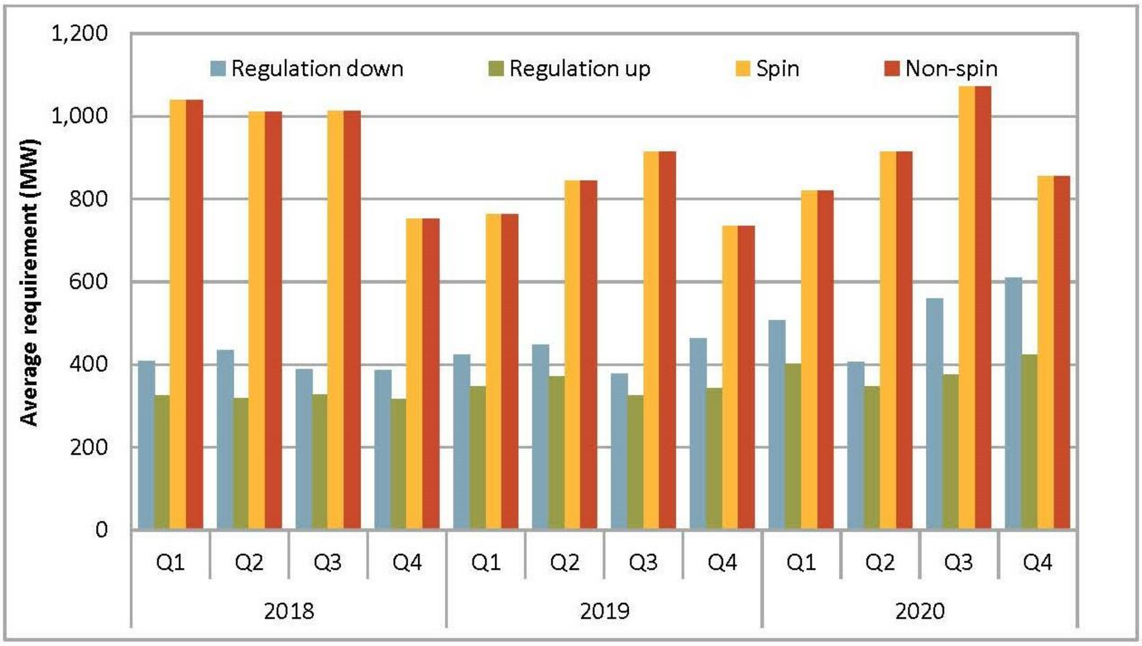
- 6.3% of the load forecast;
- the most severe single contingency; and
- 15% of forecasted solar production.

Operating reserve requirements in real-time are calculated similarly to the day-ahead market, except using 3% of the load forecast and 3% of generation instead of 6.3% of the load forecast. The total operating reserve requirements are then typically split equally between spinning and non-spinning reserves.[32]

Operating reserve requirements in the day-ahead market averaged about 1,800 MW in 2020, a 12% increase from the previous year (see Figure 9). Most regulation Up and Down is supplied by natural gas plant, hydro plant and increasingly by batteries. In the spinning and non-spinning reserve markets, most of the resources are supplied by natural gas and hydro plant.[33]

31 Department of Market Monitoring - California ISO, 2020 Annual Report on Market Issues & Performance, August 2021, p.162.
32 Ibid.
33 Ibid, pp.163-164.

Figure 9: CAISO Day Ahead Operating Reserve Requirements



Source: Department of Market Monitoring - California ISO, 2020 Annual Report on Market Issues & Performance, August 2021, p.161.

Resources providing Ancillary Services receive a capacity payment at market clearing prices in both the day-ahead and real-time markets. Capacity payments in the real-time market are only for incremental capacity above the day-ahead level.

Table 7: Day-Ahead Ancillary Service Market Clearing Prices

Weighted average prices ($/MWh)		
Ancillary service	**2019**	**2020**
Regulation down	11.74	10.97
Regulation up	13.27	13.10
Spin	7.39	9.50
Non-spin	0.75	1.00

Source: Department of Market Monitoring - California ISO, 2020 Annual Report on Market Issues & Performance, August 2021, p.165.

Table 8: Real Time Ancillary Service Market Clearing Prices

Weighted average prices ($/MWh)		
Ancillary service	**2019**	**2020**
Regulation down	23.92	16.08
Regulation up	24.55	20.12
Spin	19.48	9.58
Non-spin	6.83	9.00

Source: *Department of Market Monitoring - California ISO, 2020 Annual Report on Market Issues & Performance, August 2021, p.166.*

5.2 Fee Recovery for Market Services and ESS

5.2.1 Market Services

CAISO recovers its net operating costs ($182.6 million in 2022) via the grid management charge (GMC). CAISO has absorbed several major initiatives over recent years with no material impact to the GMC revenue requirement. This includes launching the market redesign and technology upgrade (MRTU), constructing its secure primary and secondary locations, implementing the energy management system (EMS), as well as launching the Western Energy Imbalance Market (EIM) and reliability coordinator services (also known as RC West).[34]

Table 9: 2022 GMC Revenue Requirement

GMC Revenue Requirement ($m)	2022 Budget DRAFT	Change in Versions	Budget		Chang	
			2022	2021t	$	%
Operations and Maintenance Budget	$209.80	$0.90	$210.70	$200.80	$9.90	5%
Debt Service (including 25% reserve)	14.7	-	14.7	16.9	(2.2)	-13%
Cash Funded Capital	30.0	-	30.0	28.0	2.0	7%
Other Costs and Revenues	(53.2)	(0.5)	(53.7)	(50.5)	(3.2)	6%
Operating Cost Reserve Adjustment	(19.2)	0.1	(19.1)	(13.6)	(5.5)	40%

34 California ISO, 2022 Budget and Grid Management Charge Rates, December 17, 2021, Final

GMC Revenue Requirement ($m)	2022 Budget DRAFT	Change in Versions	Budget		Chang	
			2022	2021t	$	%
Total GMC Revenue Requirement	**$182.10**	**$0.50**	**$182.60**	**$181.60**	**$1.00**	**1%**
Transmission Volume Estimate in TWh	233.5	0.0	233.5	237.3	(3.8)	-2%
Pro-forma bundled cost per MWh	$0.78	$0.00	$0.78	$0.77	$0.02	2%

Source: *California ISO, 2022 Budget and Grid Management Charge Rates, 17 December 2021, Final, p.4.*

The ISO recovers its GMC revenue requirement through unbundled grid management charges (GMC). Each unbundled service has a corresponding rate, which is paid by service users. Rates are calculated by dividing each service cost by forecasted volumes. The result is a rate per unit of use. The current design, implemented in 2012, provides for three volumetric charges and five associated fees and charges. The cost categories consist of market services, system operations, and congestion revenue rights (CRR). The design was updated in 2015, 2018, and 2021 as a result of cost of service studies.

The ISO completed its most recent cost of service study in 2020; the study used activity based costing to analyse cost and time data from 2019. The new percentage allocations and fee changes as a result of the study became effective 1 January 2021 and will remain in effect through the development of the 2023 GMC revenue requirement and resulting charges – see Table 10 and Table 11.

Table 10: Components of GMC and Billing Determinants

Type	Bill Determinant
Grid Management Charges	
Market Service Charge	Awards in MWh or MW of supply and demand excluding Transmission Ownership Rights (TORs)
Systems Operations Charge	Metered flows in MWh of supply and demand in the ISO balancing authority with the following two exceptions, TORs and qualifying exempt supply contracts
CRR Service Charge	MWh of congestion
Miscellaneous Fixed Fees	
Bid Segment Fee	Number of bid segments in the ISO market for supply or demand
Inter-SC Trades Fee	Number of trades by scheduling coordinator (SC)
SCID Fee	Monthly charge if statement produced for an SC

Type	Bill Determinant
TOR Charge	Minimum of metered supply or demand in MWh on TORs
CRR Auction Bid Fee	Number of accepted bids in CRR auctions

Source: *California ISO, 2022 Budget and Grid Management Charge Rates, 17 December 2021, Final, p.39.*

Table 11: Grid Management Charge Rates, 2022

Summary of Charges, Fees, and Rates	2022 Rate
Grid Management Charges	
Market Service Charge	$0.1484/MWh
Systems Operations Charge	$0.2004/MWh
CRR Services Charge	$0.0055/MWh
Miscellaneous Fixed Fees	
EIR Forecast Fee	$0.1000/MWh
Inter-SC Trade Fees	$1.0000/number of trades
Bid Segment Fees	$0.0050/number of bid segments
CRR Auction Bid Fees	$1.0000/number of nominations and bid
TOR Fees	$0.1800/MWh
SCID Fees (monthly)	$1,500/number of SCID
Supplemental Services Rates	
EIM Market Service	$0.0935/MWh
EIM System Operations	$0.1002/MWh
RC Service Rate	$0.0282/MWh

Source: *California ISO, 2022 Budget and Grid Management Charge Rates, 17 December 2021, Final, p.43.*

5.2.2 Ancillary Services

The cost of the market purchase of Ancillary Services is shared by the load LSE in proportion to their actual load in the system. LSE can also reduce or negate their obligations to contribute towards the Ancillary Services cost by self-providing the services.

The CAISO Tariff recovers the costs of Regulation Up and Regulation Down, Spinning Reserve, Non-Spinning Reserve, and Voltage Support. Separate hourly user rates for Regulation Down Reserve, Regulation Up Reserve, Spinning Reserve, and Non-Spinning Reserve are calculated based on costs incurred by CAISO across the Day-Ahead Market and the Real-Time Market to procure these services.[35]

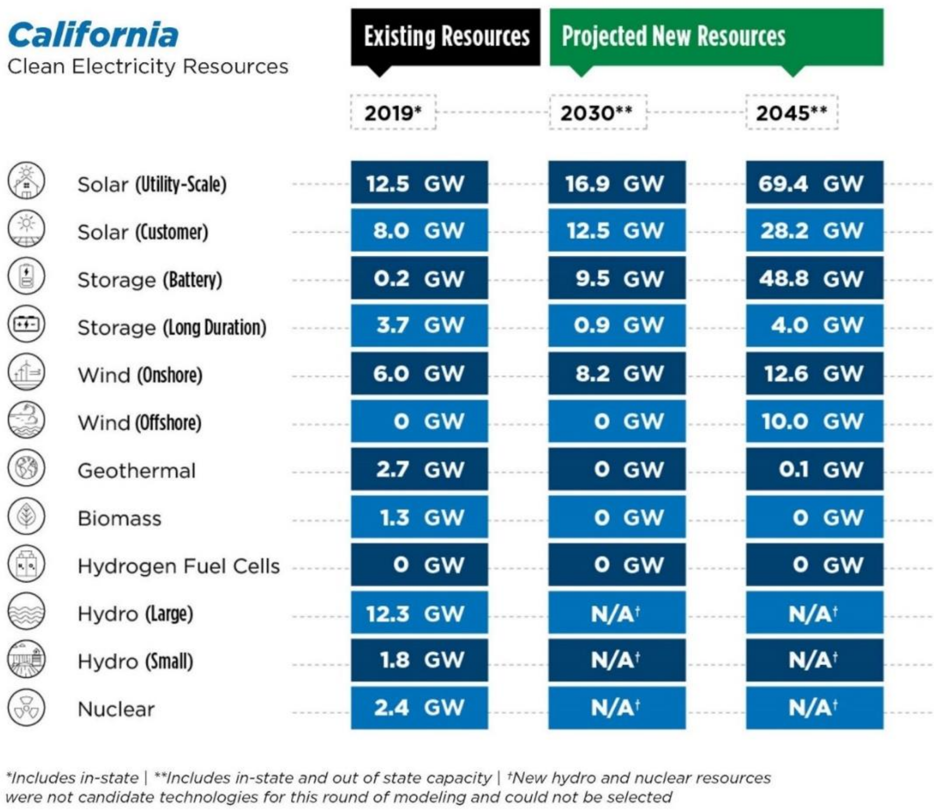
5.3 Proposed Reforms

Senate Bill 100: [36]

- sets a 2045 goal of powering all retail electricity sold in California and state agency electricity needs with renewable and zero-carbon resources; and
- updates the state's Renewables Portfolio Standard to ensure that, by 2030, at least 60% of California's electricity is renewable.

Modelling of future renewable energy developments are highlighted in Figure 10. While no new natural gas generation is selected in the Senate Bill 100 Core scenario, much of the existing natural gas capacity is retained through 2045. Installed capacity will have to increase three-fold by 2045 to achieve the Senate Bill 100 goals, driven by electrification (higher demand) and installation of intermittent generation (requires additional firming capacity).

Figure 10: In state and out of State Generation Capacity (MW) for SB 100 Core scenario – excludes existing gas generation



California
Clean Electricity Resources

	Existing Resources	Projected New Resources	
	2019*	2030**	2045**
Solar (Utility-Scale)	12.5 GW	16.9 GW	69.4 GW
Solar (Customer)	8.0 GW	12.5 GW	28.2 GW
Storage (Battery)	0.2 GW	9.5 GW	48.8 GW
Storage (Long Duration)	3.7 GW	0.9 GW	4.0 GW
Wind (Onshore)	6.0 GW	8.2 GW	12.6 GW
Wind (Offshore)	0 GW	0 GW	10.0 GW
Geothermal	2.7 GW	0 GW	0.1 GW
Biomass	1.3 GW	0 GW	0 GW
Hydrogen Fuel Cells	0 GW	0 GW	0 GW
Hydro (Large)	12.3 GW	N/A†	N/A†
Hydro (Small)	1.8 GW	N/A†	N/A†
Nuclear	2.4 GW	N/A†	N/A†

*Includes in-state | **Includes in-state and out of state capacity | †New hydro and nuclear resources were not candidate technologies for this round of modeling and could not be selected

Source: California Energy Commission, 2021 SB 100 Joint Agency Report Summary Achieving 100%, 9/3/2021, p.10.

[35] California Independent System Operator Corporation, Fifth Replacement FERC Electric Tariff (Open Access Transmission Tariff), effective as of April 1, 2022, Section 11.10.2.

[36] Officially titled "The 100 Percent Clean Energy Act of 2018".

Long term transmission planning for CAISO used the Senate Bill 100 Core state-wide high electrification load projection of 82,364 MW, of which 73,909 MW is supplied by CAISO in 2040. It is expected that the total behind-the-meter PV (BTMPV) in CAISO will reach 30,336 MW in year 2040 (41% of total demand).[37]

5.4 Federal Energy Regulatory Commission – Reform of Energy and Ancillary Services

Regional transmission organisations and independent system operators (RTOs/ISOs) are considering whether RTO/ISO energy and Ancillary Services markets in North America need reform in light of the changing resource mix and load profiles. In general, RTOs/ISOs will need more "operational flexibility" from resources to reliably serve loads as the resource mix evolves to include more VRE resources.[38]

Increasingly, RTOs/ISOs are focusing on "net load" in the operation of the system (i.e., load minus supply from intermittent generation sources), which is equivalent to dispatchable load in the WEM. Net load has several dimensions:

- expected and reasonably forecastable changes within the operating day and across seasons; and
- unexpected changes that cannot be forecasted due to the inherent uncertainty of the components of net load (e.g., meteorological conditions).

Expected changes in net load create challenging conditions for operators mainly due to steep net load ramps. FERC approved ramp capability products in CAISO, MISO (Midcontinent Independent System Operator), and the Southwest Power Pool (SPP) to manage operational uncertainty.[39]

Reform approaches to energy and Ancillary Services markets include increasing shortage prices, procuring higher quantities of existing or "traditional" Ancillary Services products and creating new Ancillary Services products. For example, CAISO's Day Ahead Energy Market Enhancement proposal would create a new day-ahead ancillary service product called an imbalance reserve that would ensure sufficient real-time dispatch capability to meet net load imbalances that arise in between the day-ahead and real-time markets.[40]

37 California ISO, 20-Year Transmission Outlook, Draft, January 31, 2022, p.18.

38 Federal Energy Regulatory Commission, Energy and Ancillary Services Market Reforms to Address Changing System Needs A Staff Paper, Document No. AD21-10-000, September 2021

39 Ibid, p.12.

40 Ibid, p.22.

6. Electricity Reliability Council of Texas

6.1 Market Design and Market Mechanisms

The Electric Reliability Council of Texas (ERCOT) serves as an independent system operator, managing the flow of electricity to 24 million customers in Texas, representing approximately 90% of Texas' electrical load. ERCOT operates a competitive wholesale electricity market, ensuring reliability for over more than 46,000 miles of transmission lines, for approximately 550 generating units and for its customers in Texas. ERCOT operates as an energy-only market with real-time, day-ahead, and ancillary service markets, performs financial settlement for the competitive wholesale bulk-power market and administers the retail market ERCOT's members include consumers, cooperatives, generators, power marketers, retailers, investor-owned electric utilities (transmission and distribution providers) and municipal-owned electric utilities.[41]

ERCOT are responsible primarily:[42]

- maintaining system reliability;
- facilitating a competitive wholesale market;
- facilitating a competitive retail market; and
- ensuring open access to transmission.

ERCOT provides the following frequency control services:

- Regulation Up – frequency regulation service to increase generation output;
- Responsive Reserve – generation reserves service;
- Regulation Down – frequency regulation service to decrease generation output; and
- Non-Spinning Reserve – generation standby service with 30 minutes notice.

ERCOT calculates the responsive reserves capacity requirements and publish their requirements in advance for the year. The prices for these Ancillary Services are the direct outcome of ERCOT's co-optimised day-ahead market.

6.2 Fee Recovery for Market Services and ESS

ERCOTS market operation costs are funded by the System Administration Fee, which is currently 55 cents/MWh (US) or average costs of $7/year (US).[43]

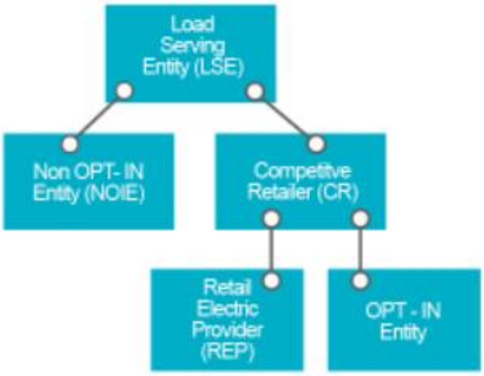
The budget for these charges is approved by the ERCOT Board and the Public Utility Commission of Texas biennially.

ERCOT System Administration fee is charged to all Qualified Scheduling Entities based on load they represent. Qualified Scheduling Entities submits bids and offers on behalf of resources or loads, which includes retail electricity providers.

41 https://www.ferc.gov/electric-power-markets
42 https://www.ercot.com/files/docs/2022/02/08/ERCOT_Fact_Sheet.pdf
43 https://www.ercot.com/files/docs/2021/02/24/2.2_REVISED_ERCOT_Presentation.pdf

On average, the four frequency services cost between $3.00/MWh to $4.00/MWh prior to the February 2021 extreme weather event (see section below). ERCOT pays clearing prices to generation providing these services from their day ahead market, which is then passed onto the LSEs (see Figure 11), who provides the electricity service to retailers and large customers.

Figure 11: Load Serving Entity (LSE) Breakdown



Source: ERCOT https://www.ercot.com/services/rq/lse

6.3 Justification for Approach

The purpose of Ancillary Services provided by ERCOT is to protect the system against unforeseen contingencies, which includes unplanned generation outage, and load or wind generation forecast errors rather than meet normal load fluctuations.

With the increase of wind generation in recent years, ERCOT implemented the System of Change Request 795, 'Addition of Intra-Hour Wind Forecast to Generation to Be Dispatched Calculation' in 2019. This improved the dispatch of generators and the efficiency of regulation deployment.

Consistent with the early setup of the market, the current co-optimisation of these services is done on a day ahead basis which is allow for efficient dispatch of all services, except non-spinning reserve and regulation down. For example, assets owner Luminant[44] operates approximately 37% of the provision of non-spinning reserves as of 2019.[45] Key arguments include that these services should be optimised on real time basis to enable greater efficiency of dispatch and minimise the overall ancillary costs.

For the System Administration Fee, the review between the Public Utility Commission of Texas and ERCOT, conducted on biennial basis, has resulted in the same charge being applied since 2010 (i.e., 55 cents/MWh (US)). ERCOT's revenue however has been increasing given the strong growth in electricity demand in Texas. The organisation revenues in 2019 exceeded the organisation's budget by 13.3%, or USD $35.4 million.[46]

44 https://www.potomaceconomics.com/wp-content/uploads/2020/06/2019-State-of-the-Market-Report.pdf

45 https://www.potomaceconomics.com/wp-content/uploads/2020/06/2019-State-of-the-Market-Report.pdf pp. 68-69

46 https://tcaptx.com/industry-news/blog-ercot-fee-stays-constant-but-generates-more-revenue

6.4 Proposed Reforms

After multiple market inefficiency reports by Independent Market Monitor and ERCOT themselves, by 2018 the organisation has decided to implement Real Time Co-optimisation of energy and Ancillary Services.[47] The technical change will be around USD $40million, which is assumed to be mostly covered by the accumulation of surplus revenue earned from the application of the System Administration Fee and strong electricity demand.

The studies on Real Time Co-optimisation highlighted the following benefits:[48]

- more timely procurement of Ancillary Services when additional amounts are required or when resources are unable to provide those services;
- more effective congestion management resulting from the ability to use a wider variety of resources to solve transmission constraints;
- reduction in manual actions by operators, including the deployment of Ancillary Services and the swapping of Ancillary Services obligations between resources; and
- improved management of Ancillary Services through consideration of the minute-to-minute changes in resource-specific capabilities, including a framework for better utilizing all types of resources.

A task force was introduced in 2018[49] and has been reporting to ERCOT's Technical Advisory Committee on the February 2021 extreme weather event. Apart from Real Time Co-optimisation, ERCOT has also undertaken Fast Frequency Response pilot tests.

However, in February 2021 record setting sub-freezing temperatures and wind chills across Texas causes multiple issues with electricity supply in the state, from forced generation outages, to controlled outages to prevent blackouts, and insufficient Ancillary Services offers for responsive reserve.[50]

A significant market redesign is underway to improve grid reliability. This includes implementation of Fast Frequency Response Service, Contingency Reserve Service and Real Time Co-optimisation of energy and Ancillary Services.[51]

47 https://www.ercot.com/files/docs/2019/01/17/RTC_One_Pager_FINAL_3.pdf
48 https://www.ercot.com/files/docs/2019/01/17/RTC_One_Pager_FINAL_3.pdf
49 https://www.ercot.com/committees/inactive/rtctf
50 https://www.ercot.com/files/docs/2021/02/24/2.2_REVISED_ERCOT_Presentation.pdf
51 http://interchange.puc.texas.gov/Documents/52373_268_1172004.PDF

7. Pennsylvania, New Jersey, and Maryland Interconnection

7.1 Market Design and Market Mechanisms

The PJM Interconnection operates a competitive wholesale electricity market and manages the reliability of its transmission grid. PJM provides open access to the transmission and performs long-term planning. In managing the grid, PJM centrally dispatches generation and coordinates the movement of wholesale electricity in all or part of 13 states (Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia and West Virginia) and the District of Columbia (covers 65 million people). PJM's markets include energy (day-ahead and real-time), capacity and Ancillary Services. [52]

PJM became a fully functioning Independent System Operator (ISO) in 1996 and, in 1997, introduced markets with bid-based pricing and locational market pricing (LMP). PJM was designated a regional transmission organisation (RTO) in 2001.[53]

Peak demand in PJM is 151.7 GW (2021), with energy consumption of 813 TWh/annum.[54] Energy is supplied from Gas (37.9%), Nuclear (32.8%), Coal (22.2%), Wind (3.3%), Hydro (2%) and other (solar, waste, oil and biofuel).[55]

PJM Market Mechanisms include the following:

- Energy Market – includes Day-Ahead and Real-Time markets:
    - The Day-Ahead Market is a "forward" market, whereby hourly prices are calculated based on generator offers and bids from buyers (i.e., utilities, financial participants), and all cleared bids and offers establish a financial position in the Day-Ahead Market;
    - Any deviations from cleared quantities in the Day-Ahead Market are settled in the Real-Time Market (a five-minute spot market for more than 10,000 different pricing points based on actual grid operating conditions);
- Capacity Market (also referred to as the Reliability Pricing Model (RPM)) – PJM procures capacity (i.e., generation, demand side management, storage) three-years ahead to ensure sufficient supply will be available to meet peak demand. Each year, PJM holds a competitive auction to obtain capacity. at the lowest reasonable price; and
- Ancillary Service Markets – includes regulation and reserves.

The Real-time Security Constrained Economic Dispatch (RT SCED) program jointly optimizes Energy and Reserves subject to transmission constraints, Reserve Requirements and prior committed Regulation services.

52 https://www.ferc.gov/electric-power-markets

53 https://www.ferc.gov/electric-power-markets

54 Monitoring Analytics, 2021 State of the Market Report for PJM, Joe Bowring, Press Briefing, 03.10.2022, p.8.

55 Ibid, p.13.

7.1.1 Ancillary Services Markets

PJM operates several markets for Ancillary Services: the Synchronized Reserve Market, the Non-Synchronized Reserve Market, the Day-Ahead Scheduling Reserve Market and the Regulation Market.

- Regulation – Hour ahead market whereby suppliers submit offers for regulation capability and performance. Five minute Regulation Market Clearing Prices (RMCP) and Regulation Market Performance Clearing Prices (RMPCP) are determined and are used in market settlements to provide revenue to suppliers and charges to purchasers of the Regulation service (i.e., LSEs).[56]
- Primary Reserve – PJM has an obligation to maintain a certain quantity of total ten minute reserves on the system, including both synchronized and Non-Synchronized Reserves. Prices and quantities are cleared every five minutes, one hour ahead of time.
  - Synchronized Reserves - Tier 1 and Tier 2 suppliers[57] must be capable of increasing their output within ten minutes following a call for a Synchronized Reserve Event. If the forecasted amount of Tier 1 estimated for a given duration is insufficient to meet the PJM Synchronized Reserve Requirement, PJM must commit resources to operate at a point that deviates from economic dispatch in order to provide the remainder of the requirement.[58]
  - Non-Synchronised Reserves – must also be capable of increasing output with ten minutes.
- Day Ahead Scheduling Reserve (DASR) – procurement of supplemental, 30-minute reserves on a day-ahead, forward basis.

LSEs must meet the system ancillary service requirements and the share of the obligation is determined according to the LSE's share of the total load in the PJM-RTO. LSEs can fulfil its obligations:

(a) self-schedule the entity's own resources;

(b) bilateral contracts to purchase services from other participants; or

(c) buying in the Ancillary Services in the PJM market.

PJM also provides the reactive power services and black-start services.

7.1.2 Reactive Power

Reactive power[59] compensation was a by-product of “functional unbundling” under Order No. 888 (1996) and was one of the original six (6) Ancillary Services created in the PJM. In Order No. 2003, the Commission required that units interconnecting have a minimum power factor range of 0.95

56 PJM, PJM Manual 11: Energy & Ancillary Services Market Operations, Revision: 119, Effective Date: March 23, 2022, Prepared by Day-Ahead and Real-Time Market Operations, p.77.

57 Tier 1 - Dispatched on economics and able to ramp up in 10 minutes from current output. Tier 2 are resources that are synchronised to the grid but may incur costs in becoming synchronised (e.g., start-up costs).

58 Ibid, p.93.

59 PJM, Reactive Power Compensation Overview, Thomas DeVita, Assistant General Counsel Office of the General Counsel, Reactive Power Compensation Task Force November 5, 2021

leading to 0.95 lagging, unless the transmission provider establishes a different power factor range.

Generators are compensated by PJM (specific tariffs apply) if they are required to operate outside established power factor ranges.

7.1.3 Black Start

Transmission customers must purchase Black Start Capability[60] from PJM. PJM is responsible for coordinating payments for all Black Start Capability directly to the generating Facilities that provide the service.

Black start costs consist of fixed black start service costs, variable black start service costs, training costs, fuel storage costs, and an incentive payment. Black start uplift credits are paid to units scheduled in the day ahead energy market or committed in real time to provide black start service under the Automatic Load Rejection (ALR) option or for black start testing.

Black Start costs are recovered via charges on Network and Point-to-Point Transmission Customers based on their monthly transmission use on a megawatt basis.

The sum of all customers' monthly charges equal one-twelfth (1/12) of the total annual black start revenue requirements that are credited to owners of black start units as well as a share of the applicable Day-ahead and Balancing Operating Reserve Credits that are credited to generation owners of black start units for the month.

7.1.4 Market Fees

Market overhead costs are unbundled and on charged to transmission customers with different billing determinants:[61]

(1) Control Area Administration – monthly formula rate is charged to transmission customers based on their usage of the PJM transmission system. Monthly transmission use (in MWh) includes network customers' real-time load and point-to-point customers' real-time energy use.

(2) Financial Transmission Rights (FTR) Administration:

- Component 1: monthly formula rate is charged to FTR holders based on FTR MW and hours each FTR is in effect.
- Component 2: monthly formula rate is charged to FTR Auction participants based on the number of hours associated with each FTR obligation bid submitted in an FTR Auction (this rate is multiplied by 5 for FTR options).

(3) Market Support:

- Component 1: monthly formula rate is charged to transmission customers, based on their network load and exports, to providers of generation and imports, and to day-ahead energy Market Participants based on their accepted increment offers, decrement bids, and up-to congestion bids.

60 PJM Manual 27: Open Access Transmission Tariff Accounting. Cost recovery detailed in Schedule 6A, Black Start Service

61 https://www.pjm.com/-/media/markets-ops/settlements/custgd.ashx

- Component 2: monthly formula rate is charged for each energy bid/offer segment price/quantity pair submitted, including those submitted during the rebidding period.

(4) Capacity Resource and Obligation Management:

- Monthly formula rate is charged to LSEs based on their daily unforced capacity obligations and to capacity resource owners based on their daily unforced capacity (including Fixed Resource Requirement entities).

PJM files Schedule 9 rate submissions to the FERC considering energy demand forecasts, a Cost of Service Review, and required changes to billing determinants.[62]

Figure 12: PJM Market Fees 2021 (USD)

Fourth Quarter 2021 Service Category Rates
Effective 10/1/21 through 12/31/21

Schedule							
		9-2 Financial Transmission Rights (FTR) Administration Service		9-3 Market Support (MS) Service			
	9-1 Control Area Administrative on Service (per MWh)	9-2 FTR Service Rate Component 1 (per FTR MWh)	9-2 FTR Service Rate Component 2 (per FTR bid hour)	9-3 MS Service Rate Component 1 (per MWh)	9-3 MS Service Rate Component 2 (per bid/offer segment)	9-4 Regulation & Frequency Response Administration Service (per MWh)	9-5 Capacity Resource & Obligation Management Service (per MW Day)
2021 Stated Rate	0.2262	0.0030	0.0020	0.0499	0.0746	0.3035	0.1156
4Q 2021 PJMSettlement Rate* Offset	N/A	N/A	N/A	(0.0039)	N/A	N/A	N/A
Quarterly Refund Rate**	(0.0388)	(0.0024)	(0.0020)	---	(0.0729)	---	(0.0413)
Effective Rates***	0.1874	0.0006	0.0000	0.0460	0.0017	0.3035	0.0743

* PJMSettlement Rate is billed separately for services rendered by PJM Settlement, Inc. as outlined on Schedule 9-PJMSettlement.
** The Quarterly Refund Rate is set quarterly and the rates listed above will be in place from October through December 2021 billing.
*** The Effective Rates reflect the net billing for Schedule 9-1 through 9-5 rates from October 1, 2021 through December 30, 2021 business excluding 9-PJM Settlement Rate.

www.pjm.com 2 PJM©2021

Source: https://www.pjm.com/committees-and-groups/committees/fc/pjm-admin-cost-rates

62 FERC, Administrative Rate Proposal, Prepared by Jim Snow, Members Committee, September 29, 2021

7.2 Allocation of Fees and Charges

Table 12 shows the breakdown of wholesale and transmission costs in the PJM.

Table 12: PJM Wholesale and Transmission Costs (USD – 2021)

Category	$/MWh	Percent of Total
Load Weighted Energy	$39.78	61.3%
Capacity	$10.96	16.9%
Transmission	$12.76	19.7%
Ancillary	$0.87	1.3%
Administration	$0.54	0.8%
Total Price	$64.91	100.0%

Source: Monitoring Analytics, LLC, State of the Market Report for PJM, Volume 1: Introduction, Independent Market Monitor for PJM, 3.10.2022, p.18.

Table 12 highlights the problems of using administrative and Ancillary Services charges to send cost reflective price signals to final customers. That is, you can attempt to send price signals to final customers to modify behaviour, but the signals will be swamped by price signals from other cost categories – energy, capacity and transmission.

However, while final customers may not respond to cost signals for market administration, Market Participants may respond to the price signals provided by Ancillary Services charges, particularly as these charges are likely to increase as intermittent generation increases. For example, given that most charges are levied on LSEs, it is possible for LSEs avoid these charging by altering their behaviour. In relation to Ancillary Services, LSEs can fulfil its obligations by either self-scheduling their own resources, bilateral contracts to purchase services from other participants, or buying these services from Ancillary Services markets in the PJM market.

Within PJM, a curtailment service provider (CSP) can provide frequency regulation and reserves. Currently, there are several electricity customers that provide synchronized reserves into the wholesale market.[63]

7.3 Proposed Reforms

Ten of PJM's 14 jurisdictions have enacted legislation requiring that a defined percentage of retail suppliers' load be served by renewable resources, for different definitions across jurisdictions. These are typically known as renewable portfolio standards (RPS).[64] Despite these requirements, wind and solar generation was 4.2% of total generation in PJM in 2021.[65]

63 Retail Electricity Consumer Opportunities for Demand Response in PJM's Wholesale Markets

64 Monitoring Analytics, LLC, State of the Market Report for PJM, Volume 1: Introduction, Independent Market Monitor for PJM, 3.10.2022, p.54.

65 Ibid, p.55.

Renewable resources account for more than 90% of the 135,588 MW actual capacity in PJM's Interconnection queue, it is estimated that only 35%, or 47,452 MW, of these generation projects are expected to come into service, which is still substantial.[66] The increase in renewable plant will be needed to replace aging coal and nuclear plants in PJM states. The ability of new, natural gas-fired generating units to replace reliability attributes (inertia, voltage support, frequency response, short-circuit current, etc.) previously provided by coal and nuclear units deactivations is a major focus for PJM Interconnection.[67]

In 2011, FERC issued Order 755, which called for more equitable treatment for fast responding resources, such as batteries, in the frequency regulation market. The PJM Interconnection implemented those rules in 2012, splitting its frequency regulation market into a fast ramping services (so-called RegD) and slower ramping service (or RegA).[68]

As a result, significant investment in battery storage occurred and exposed a flaw in the design of PJM's frequency regulation market. Sometimes a battery providing fast ramping frequency regulation service would be depleted and go from discharge to charging mode, which would increase load on the grid at a time that generation had to increase rapidly to meeting rising demand. As a result, more RegD resources would have to be activated to compensate for the loss of RegA resources.

These failures in the regulation market have resulted in both the "underpayment and overpayment of RegD resources and in the over procurement of RegD resources in all hours."[69] Proposals to FERC to correct the flaws have previously been rejected by FERC.

66 https://insidelines.pjm.com/potential-reforms-for-transmission-planning-cost-allocation-and-generator-interconnection-discussed/

67 PJM Planning Division, Grid of the Future: PJM's Regional Planning Perspective. 10 May 2022, pp.39-40.

68 https://www.utilitydive.com/news/is-the-bloom-off-the-regd-rose-for-battery-storage-in-pjm/503793/

69 Op cit, Monitoring Analytics, 2022, p.69.

8. I-SEM, Ireland

8.1 Market Design and Market Mechanisms

The Integrated Single Electricity Market (I-SEM) is a gross pool wholesale electricity market that covers over 2.5 million customers across Ireland and Northern Ireland.[70] It replaced the Single Electricity Market (SEM) in 2018 and is designed to integrate all-island (i.e., Republic of Ireland and Northern Ireland) electricity market with European electricity markets, making optimal use of cross-border transmission assets. Natural gas fired generation led the mix of power generation in 2020 (48.9%) followed by wind (37.7%), coal (6.8%), peat (3.4%) and other forms of energy generation (6.8%). The I-SEM was a net exporter of energy in 2020, with imports being only 1.7% of all energy generation in Ireland.[71]

The I-SEM is jointly regulated by the Commission of Energy Regulation in Ireland and the Utility Regulator in Northern Ireland. Both parties govern the I-SEM through the SEM Committee which is responsible for the administration of market codes, licensing of market operators and participants, and monitoring the operation of the I-SEM and conduct of participants.

The transmission system operators (TSOs) in Ireland and Northern Ireland are EirGrid and SONI respectively. EirGrid and SONI make up the joint ventures in the Single Electricity Market Operator (SEMO) and SEMOpx. As a TSO, EirGrid and SONI are responsible for the market operations, settlement, credit risk management and registration of participants in the I-SEM. These market operations include managing the day-ahead, intraday, balancing, capacity, forwards and financial transmissions Rights (FTR) options markets along with the Ancillary Services (system services) in the I-SEM.

I-SEM is involved in a coupled market which involves buyers and sellers from different bidding zones across Europe that are centrally collected to maximise the most efficient trades. Both EirGrid and SONI are the nominated electricity market operators (NEMOs) and jointly operate under the SEMO (manages Balancing and Capacity Markets) and SEMOpx (manages Day Ahead Market (DAM) and Intraday Electricity Market (IDM)) in these cross-border markets.[72] As a NEMO, EirGrid and SONI are responsible for interacting with the European Market Coupling Operator to facilitate trading for participants in Ireland with those across the border. Participants in Ireland and Northern Ireland submit bids and offers to SEMO and SEMOpx, who acts as the central counterparty for all trades.[73]

8.2 Market Services and System Services

As TSOs, EirGrid and SONI are responsible for operating, maintaining, and developing the transmission system. Currently, the TSO's levy Transmission Use of System (TUoS) Charges to suppliers, generators and autoproducers[74] to recover the costs incurred in undertaking the above mentioned activities. However, implementation of a beneficiary-pays or causer-pays model are

[70] https://selectra.ie/energy/guides/energy-market/sem-isem#:~:text=The%20ISEM%20has%20over%202.5,bought%20and%20sold%20through%20it

[71] https://electroroute.com/isem-in-2020/

[72] https://www.sem-o.com/markets/balancing-market-overview/

[73] SEM Committee, Quick Guide to the I-SEM, https://www.semcommittee.com/sites/semc/files/media-files/ISEM%20quick%20guide_1.pdf

[74] Autoproducers are customers who mainly produce power for their own use but may also export surplus power.

expected to be made in coming years with the SEM Committee currently consulting with key stakeholders regarding the allocation of these charges.

The services provided by the TSOs include network and system (ancillary) services. Network service charges are levied for the use of the transmission system infrastructure and for the transportation of electricity to both demanders and generators of electricity. System service charges are issued to recover the costs of procuring services necessary for the secure and economic operation of the transmission system.

The magnitude of these tariffs is dependent on the size of the energy user and whether the generator is directly connected to the transmission system or connected to the transmission system via the distribution system. These TUoS tariffs are split into three categories:

(1) **Demand transmission service**. Network and system services charged to suppliers (customers of generators) for using the system to serve their customers connected either to the transmission system or the distribution system.

(2) **Generation transmission service**. Network and system services charged to generators that are connected to either the transmission or distribution system for using the system to export electricity for sale and import power for generation start-up.

(3) **Autoproducer transmission service**. Network and system services charged to autoproducers that are connected to either the transmission or distribution system for using the system to export their electricity for sale or import to meet on-site demand.

Table 13: TUOS Charges

Type of charge	Description
Demand charges	
Network capacity charge	Per MW charge for each MW of charging capacity in the charging period. [75]
Network unauthorised usage charge	Per MWh charge for the consumption of energy transferred in excess pf the customer's maximum import capacity in the charging period.[76]
Network transfer charge	Per MWh charge for the consumption of energy transferred in the charging period
System services charge	Per MWh charge for the consumption of energy transferred in the charging period.

[75] Charging period means a period of time starting at 00:00 on the first day of each month and ending at the end of the 24th hour (23:59:59) on the last day of the same calendar month during which a user is supplied with service by EirGrid or SONI.

[76] A customer's maximum import capacity is the upper limit on the total electric demand you can place on the network system.

Type of charge	Description
Generator charges	
Network location-based capacity charge	A charge for each MW of the maximum export capacity[77] at the entry point of the transmission or distribution system for the charging period.
System services trip charge	A charge to generators of electricity that suddenly and unexpectedly, disconnect from the transmission system resulting in the stop of supply of electricity.
System services short notice declaration charge	A charge to generators of electricity for changing declarations at short notice.
System services generator performance incentive charge	Charges that incentivise generators of electricity to perform at a level that enhances system security and reduces operating costs.

Source: EirGrid, Statement of Charges Applicable from 1st October 2021, publication date 01/09/2021

In addition to TUoS tariffs, the TSO's also charge participants an application fee.

8.3 Delivering a Secure, Sustainable Electrical System

EirGrid and SONI offer financial incentives for conventional and renewable generation to provide flexible services to meet the challenges of operating the electrical system in a secure manner while achieving Ireland's 2020 renewable electricity targets. The 14 system services that form part of 'DS3' services is provided in Table 14, although only 12 services have been procured to date.

Table 14: DS3 System Services

Service Name	Units	Description
Synchronous Inertial Response (SIR)	MWs^2h [(a)]	(Stored kinetic energy) * (SIR Factor – 15)
Fast Frequency Response (FFR)	MWh	MW delivered between 150 ms and 10 seconds
Primary Operating Reserve (POR)	MWh	MW delivered between 5 and 15 seconds
Secondary Operating Reserve (SOE)	MWh	MW delivered between 15 to 90 seconds

77 The maximum amount of electricity which is permitted to flow through the connection point to the transmission or distribution system.

Service Name	Units	Description
Tertiary Operating Reserve 1 (TOR1)	MWh	MW delivered between 90 seconds to 5 minutes
Tertiary Operating Reserve 2 (TOR2)	MWh	MW delivered between 5 minutes to 20 minutes
Replacement Reserve – Synchronised (RRS)	MWh	MW delivered between 20 minutes to 1 hour
Replacement Reserve – Desynchronised (RRD)	MWh	MW delivered between 20 minutes to 1 hour
Ramping Margin 1 (RM1)	MWh	The increased MW output that can be delivered with a good degree of certainty for the given time horizon.
Ramping Margin 3 (RM3)	MWh	
Ramping Margin 8 (RM8)	MWh	
Steady State Reactive	Mvarh (b)	(Mvar capability) *(% of capacity that Mvar capability is achievable)
Dynamic Reactive Response (DRR)		Not procured to date
Fast Post Fault Active Power Recovery (FPFAPR)		Not procured to date

Notes: (a) *stored kinetic energy is equal to MW of power multiplied by the velocity squared*

(b) *Mega volt amps (reactive) hours*

Source: Government of Ireland, Implementation Plan for Ireland, To meet the requirements of the recast Electricity Market Regulation, 2019/943, publication date 27/07/2020

Payment is based on availability of service provision, with a fixed tariff in place for each service (see Table 15), and payments adjusted by scalars based on enhanced technical delivery or scarcity due to high levels of VRE.

Table 15: SONI, System Services Payment Rates (1 October 2021 to 31 Dec 2021) – exclusive of VAT

Payment Type	Payment Rates
Synchronous Inertial Response (SIR)	£0.0045/MWs^2h
Primary Operating Reserve (POR)	£2.95/MWh
Secondary Operating Reserve (SOR)	£1.78/MWh
Tertiary Operating Reserve 1 (TOR1)	£1.41/MWh

Payment Type	Payment Rates
Tertiary Operating Reserve 2 (TOR2)	£1.13/MWh
Replacement Reserve (Synchronised) (RRS)	£0.23/MWh
Replacement Reserve (De-Synchronised) (RRD)	£0.51/MWh
Ramping Margin 1 (RM1)	£0.11/MWh
Ramping Margin 3 (RM3)	£0.16/MWh
Ramping Margin 8 (RM8)	£0.15/MWh
Steady State reactive Power (SSRP)	£0.21/MVArh
Fast Frequency Response (FFR)	£1.97/MWh
Fast Post Fault Active Power Recovery (FPFAPR)	£0.14/MWh
Dynamic Reactive Response (DRR)	£0.04/MWh

Source: SONI, DS3 System Services Statement of Payments, applicable from 1 October 2021 to 30 September 2022.

For comparison with the above System Service charges, average monthly wholesale energy prices in I-SEM vary from 78£ in January 2021 to 195£ in September 2021.[78]

The allocation of system services costs is included in the TUOS charge (see 3.7.2).

8.4 Proposed Reforms

8.4.1 Cost Allocation of System Services

The SEM Committee, in collaboration with EirGrid and SONI are currently implementing reforms to the allocation and frequency of system services charges in the I-SEM. Since 2020, the SEM Committee has consulted with key stakeholders, with further consultation expected in 2022.

The system charges levied by EirGrid and SONI are currently included in the TUoS tariff, along with the network charges, which are charged on an annual basis. This was previously a practical method of cost recovery, as system services were made up a relatively small and predictable portion of the TSO's costs. With renewable energy making up a larger portion of the generation mix, the electricity grid has seen an increase in the quantum and variability of system service costs.

[78] https://www.statista.com/statistics/1271371/ireland-monthly-wholesale-electricity-price/

As of 14 April 2022, the SEM Committee has outlined 4 options regarding the allocation and frequency of system services charges.[79]

- **Option 1 – Base case**. The process for recovering system services costs would remain the same.
- **Option 2 – Annual supplier-based charge.** This involves creating a new standalone all-island charge to suppliers. Similar to the base case option, the TSOs would provide an annual forecast of the revenue required to recover the system services costs, and a MWh charge would be levied on suppliers' dependent on this all-island energy forecast. This option follows a beneficiary-pays approach, where the supplier who benefits from a secure and economic operation of the system must pay for the generators who are called upon by the TSO to provide this service due to other generators causing an imbalance in the system.
- **Option 3 – Trading period supplier-based charge.** Under this option the System Services costs over a defined trading period would be levied on Suppliers based on their MWh demand for that trading period. Whilst the granularity (e.g., hourly, daily, monthly, yearly etc.) of the Trading Period was not specified, it was assumed that costs would be allocated to those whose customers were consuming electricity in the Trading Period, pro rata to their consumption.
- **Option 4 – Allocation of costs to grid users causing increased costs.** This follows a causer-pay approach where system services charges are borne by grid users (generators and interconnectors) that drive imbalances in the electricity grid. This would incentivise users to impose lower costs on the system relative to other grid users, putting downward pressure on overall system services costs.

[79] SEM Committee, System Services Future Arrangements High Level Design Decision SEM-22-012, https://www.semcommittee.com/sites/semc/files/media-files/System%20Services%20Future%20Arrangements%20High%20Level%20Design%20Decision%20Paper.pdf

9. Great Britain (National Grid)

9.1 Market Design and Market Mechanisms

The National Grid Electricity System Operator Limited (ESO) operates the National Electricity Transmission System. The ESO provides a range of services to maintain supply reliability which are termed Balancing Services.

9.2 Balancing Service

The detailed Balancing Services are shown in Table 16.

Table 16: Balancing Services

Name	Description
Constraints (Transmission)	The costs incurred when there is a need to increase or decrease power flows from one part of the network to another part of the network due to a limit on the transmission network (i.e., the constraint).
Constraints (RoCoF)	The costs that arise from reducing the size of the largest possible infeed loss or bringing on more generation to increase the amount of inertia.
Response	A service used to keep the system frequency close to 50Hz. Fast acting generation and demand services are held in readiness to manage any fluctuation in the system frequency, which could be caused by a sudden loss of generation or demand.
Fast Reserve	This service provides the rapid and reliable delivery of active power through an increased output from generation or a reduction in consumption from demand sources. There are three categories: Firm Fast Reserve, Optional Fast Reserve and Optional Spin Generation.
Reactive	Management of voltage levels across the grid is needed to make sure it stays within operational standards and to avoid damage to transmission equipment. Voltage levels are controlled by reactive power, providers are paid to help manage voltage levels on the system by controlling the volume of reactive power that they absorb or generate.
STOR	Short-Term Operating Reserve (STOR) allows extra power to be held in reserve for when it is needed. It helps to meet extra demand at certain times of the day or if there is an unexpected drop in generation.
Operating Reserve	Positive Reserve is required to operate the transmission system securely and provides the reserve energy required to meet the demand when there are shortfalls, due to demand changes or generation breakdowns. It is managed in the Balancing Mechanism, through trades, or SO-SO[a] services.

Constraints (AS)	Ancillary Services constraint costs including mandatory and commercial inter-tripping costs, where the ESO contracts ahead of time to manage a known transmission issue.
Black Start	Black Start would be used to restore power in the event of a total or partial shutdown. This is currently bilaterally contracted with power stations who can start and reenergise the system at the ESO's instruction.
Constraint (Voltage)	To access Reactive Power, a generator is sometimes required to be synchronised to the network. In this case, the energy from the generator is bought in order for the reactive power to be delivered.
Minor Components	Miscellaneous costs, such as Balancing Mechanism actions not accounted for elsewhere or other general costs.
Other Reserves	Other reserves paid for through commercial contracts such as the demand turn-up service.
Negative Reserve	A Negative Reserve service can provide the flexibility to reduce generation or increase demand to ensure supply and demand are balanced.
Energy Imbalance	Energy imbalance is the difference between the amount of energy generated in real time, the amount of energy consumed during that same time, and the amount of energy sold ahead of the generation time for that specific time period. The monthly energy imbalance cost can be negative or positive depending on whether the market was predominantly long or short.
ESO internal costs	The internal costs of operating the ESO in accordance with RIIO-T1,[b] ESO Incentive Arrangements 2018-2021 and the Transmission Licence.

Notes: (a) *System Operator to System Operator services*

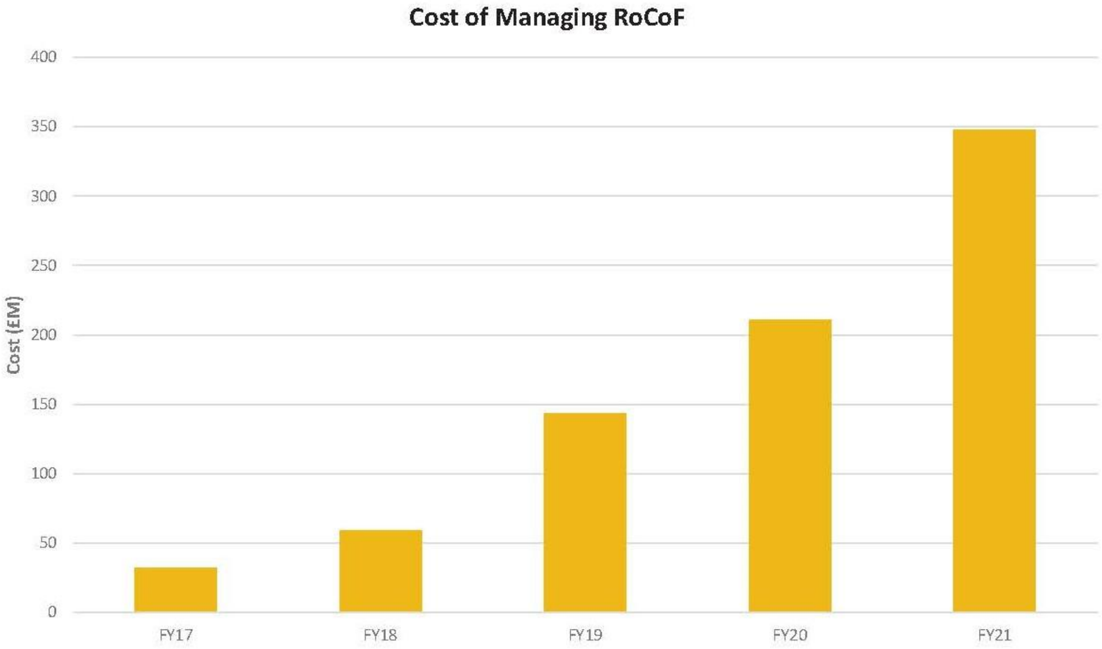
(b) *Revenue = Incentives + Innovation + Outputs (RIIO); T1 is a specific tariff.*

Source: *National Grid ESO, Balancing Services Charges Taskforce, Final Report, 31/05/2019, pp.10-11.*

Inertia Services

Due to high levels of renewable penetration in the UK, the cost of managing inertia in Great Britain increased substantially from 2017 to 2021 (see Figure 13).

Figure 13: Costs of Managing RoCoF in Great Britain



Source: System Inertia Monitoring, National Grid ESO, Ian Dytham, Webinar (https://www.naspi.org/node/898)

To help manage system frequency and decrease costs of managing it, National Grid ESOO deployed a metering and forecasting solution to measure and monitor inertia and secured ten net zero inertia contracts. The contracts start in April 2024 with a total value of £323 million ($421 million) and are split five each between synchronous condensers and grid forming converters.[80]

These solutions can help resolve insufficient short circuit levels (SCL) in various locations across Scotland and also provide a 'green' form of inertia (supplied from wind farms for example) to help keep the electricity system stable.

9.2.1 Allocation of BSUoS charges

A single Balancing Service Use of System (BSUoS) charge covers the costs of providing all the above services and is calculated monthly. Charges are apportioned on a half hourly £/MWh basis and are levied on wholesale generators, suppliers (retailers) and directly connected transmission customers. Distribution network operators, embedded generators and interconnectors do not pay these charges. This creates a competitive disadvantage to transmission-connected generation relative to other forms of generation which could result in distortions to dispatch and investment in the wholesale electricity market.

80 https://www.smart-energy.com/industry-sectors/energy-grid-management/national-grid-eso-advances-inertia-management-on-gb-grid/

Ofgem recommended that BSUoS should be recovered from "final demand" and not from transmission-connected generation from 2021:[81]

> *"charging balancing services charges for demand on the basis of gross demand at the Grid Supply Point so that suppliers cannot reduce their liability for balancing services charges by contracting with Smaller Distributed Generators (and exporting on-site generation)."*

Previously, Ofgem had initiated the first BSUoS Task Force (led by National Grid ESO) on 28 November 2018, led by the ESO to provide direction on BSUoS charges. The first Task Force recommended the following:[82]

> *"As the BSUoS charge therefore cannot feasibly provide an effective cost reflective and forward-looking signal which will influence user behaviour to the benefit of consumers, BSUoS should be treated as a cost-recovery charge. Recovery of the balancing services costs, as arising from the total costs incurred by the ESO, should still be recovered even if not intended to provide a forward-looking incentive to market parties."*

The BSUoS Task Force also indicated that BSUoS prices are relatively small compared to other forward-looking signals provided in the market (e.g., wholesale market, capacity market, imbalance settlement price, etc.). It was suggested that Market Participants would prioritise reacting to other signals and not signals provided by BSUoS prices. For example, if BSUoS costs are expected to be high a generator may increase its prices in response, rather than avoid BSUoS by reducing generation.[83]

Subsequently Ofgem asked the Electricity System Operator (ESO) to launch an industry Task Force (the second BSUoS Task Force) to assess who should be liable for BSUoS charges and how these charges should be recovered.

The Second Balancing Services Task Force was launched by the National Grid ESO in January 2020, in response to Ofgem's request of 21st November 2019.[84]

The key conclusions were the following:[85]

- "Final Demand" should pay all Balancing Services charges, subject to sufficient notice to industry prior to implementation; and
- Volumetric fixed BSUoS charge would deliver overall industry benefit, and that the total length of the fix and notice period should be around 14/15 months in length.

9.3 Justification for Approach

The following justifications were provided for the Second Balancing Service Task Force's conclusions:

81 Ofgem, Targeted charging review: decision and impact assessment, 21 November 2019, p.163.

82 National Grid ESO, Balancing Services Charges Taskforce, Final Report, 31/05/2019, pp.5.

83 Ibid, p.20.

84 https://www.ofgem.gov.uk/system/files/docs/2019/11/open_letter_on_the_balancing_services_charges_taskforce.pdf

85 Second Balancing Services Charges Task Force (led by National Grid ESO), Final Report, 30th September 2020, p.3.

- The pass-through process generated additional transaction costs, i.e., those costs that are incurred as a result of having a BSUoS liability, compared to a methodology where those costs were paid only by Final Demand. [86]
- A banded fee per site (or connection point) was considered as an alternative to unit charging but was rejected on the basis that it was a more complex structure.[87]

Ofgem commissioned independent analysis by LCP and Frontier Economics of the proposals which found that recovering BSUoS costs entirely from demand is likely to reduce overall system costs and customer costs. The system benefits arise primarily from removing the disparity of treatment between different forms of generation and the disadvantage to transmission-connected generation. Consumer benefits arise because the increase in the BSUoS demand charge is more than offset by reductions in wholesale prices and lower carbon support payments.[88]

Ofgem's final decision was for the liability of BSUoS charges to be placed solely on Final Demand, and the end of the existing arrangements (i.e., liability on suppliers and large Generators) to occur on 1 April 2023.[89]

86 Ibid, p.11.

87 Ibid, p.3.

88 LCP/Frontier Economics, Wider System and Distributional Impacts of Recovering Balancing Service Costs from Demand, June 2021.

89 Ofgem, Connection and Use of Systems Code (CUSC) modification proposal (CMP) 308 – Decision and final impact assessment, 25 April 2022

10. Fast Frequency Response

Fast Frequency Response (FFR) refers to the delivery of rapid active power increase or decrease by generation or load in a timeframe of 2 seconds or less, to correct a supply/demand imbalance and assist in managing power system frequency.

The requirement for this service is due to a reduction in system inertia caused by the anticipated retirement of large synchronous generation units which are not being replaced. New generation will predominately be from inverter connected generation, including large scale solar PV, wind power, batteries and behind-the-meter distributed resources like rooftop solar PV, that do not provide sufficient inertia to stabilise system frequency.

It is anticipated that the FFR will help reduce the overall cost of frequency control Ancillary Services relative to the expected future costs under a continuation of the current market ancillary service arrangements or other alternative arrangements.

FFR services have been and are being implemented in many jurisdictions to help maintain frequency control with high levels of intermittent generation. This includes the following:

- in the WEM, AEMO has developed a draft specification for a NCESS FFR service (restricted to particular parts of the SWIS) with the Facility able to provide a full response within one second to restore system frequency. The current requirement is 100 MW to be enabled from 1 October 2022. [90] This is a transitional measure until the full suite of ESSs are implemented on 1 October 2023. As a Non-co-optimised ESS enabled by AEMO, costs will be recovered from loads (Grid MWh);
- in the NEM, the FFR service (within 2 second response) is due to commence in October 2023 and will be similar to existing frequency control contingency services. This means it will be co-optimised with the spot energy market. The costs of enabling and providing FFR will be recovered in the same way that existing contingency services in the NEM are recovered (causer-pays methodology);[91]
- the National Grid has implemented a range of FFR services. This includes Dynamic Containment (post fault service), Dynamic Moderation (pre-fault with response 1 second or less) and Dynamic Regulation (pre-fault with response 10 seconds or less).[92] Dynamic Containment would be similar to FFR services that will be implemented in the WEM and NEM. The costs of these services would be included in the BSUoS charges; and
- PJM uses batteries and flywheels for dynamic regulation services, responding to AGC signals. Suppliers are paid a price scaled by how rapidly they respond, encouraging faster response. PJM costs are recovered from LCEs.

90 AEMO, Draft NCESS Service Specification (Fast Frequency Response), 16/5/2022

91 AEMC, Fast Frequency Response Market Ancillary Service, Final report, 15 July 2021

92 https://www.nationalgrideso.com/industry-information/balancing-services/frequency-response-services

11. Comparison of Jurisdictional Approaches to Cost Allocation

Appendix 1 provides a mapping of market services and ESS in the WEM to similar services in other jurisdictions.

Appendix 2 provides a detailed summary table comparing each jurisdictions' charging practices for Market Fees and Ancillary Services, potential reforms and future charging practices.

Table 17 provides a high level summary, as well as Marsden Jacob's views on whether current or proposed charging practices reflect the causer-pays methodology (low to high adherence).

EPWA and Marsden Jacobs consulted on the content of Table 17 with the CARWG on 5 May 2022 and with the MAC on 28 June 2022 – both the CARWG and the MAC generally agreed with this assessment.

Table 17: Adherence to Causer-Pays for Market Fees and Ancillary Services, by Jurisdiction

Service Category	Service	Cost Recovery Method	Causer-Pays Adherence
WEM			
Market and System Operator		Charge on Grid MWh for Market Participants	Medium Partially excludes other causers such as DER and fully excludes network operators.
Ancillary Services	Frequency Regulation	Loads and intermittent generators (Grid MWh).	Low Frequency regulation costs are not driven by Grid MWh consumed or generated. Other causers are excluded, such as scheduled generators and DER.
	Contingency Reserve Raise	Modified runway method to allocate costs to generators.	High More of the costs allocated to the largest generator operating in a Trading Interval. Is consistent with causer-pays methodology.
	Contingency Reserve Lower	Allocated to loads based on Grid MWh.	Medium Costs allocated across all loads, which includes large commercial and industrial loads who are the major 'causer' of the requirement for this service.

Service Category	Service	Cost Recovery Method	Causer-Pays Adherence
	Inertia	Loads, network operator and generators.	Medium Costs split evenly between beneficiaries, which provides incentives for participants to improve 'ride-through' capability of equipment.
NEM (Australia)			
Market Operator		Mixture of fixed and variable charges on participants (includes aggregators) and network operators.	Medium However, still includes variable charges even though these costs do not vary with usage or demand. Competition considerations could be important, as moving from a $/MWh to a $/user charge will have relatively larger impacts on smaller retailers/aggregators and could be seen as a barrier to entry.
Ancillary Services	Frequency Regulation	Causer-pays methodology to determine contribution factors for loads and generators.	High
	Contingency Reserve	Grid MWh for loads and generators.	Medium
NEMS (Singapore)			
Market Operator		Fixed and variable fees on Market Participants.	High
Ancillary Services	Regulation	Loads and first 10 MW of each generation Facility being dispatched.	Medium
	Reserve	Variant of runway model to calculate costs for each dispatchable Facility	High Most costs allocated to largest generator in operation.

Service Category	Service	Cost Recovery Method	Causer-Pays Adherence
CAISO			
Market Operator		Unbundled Grid management charge on service users ($/MWh).	Low
Ancillary Services		Unit charge on Load Serving Entities.	Low
ERCOT			
Market Operator		Unit charge on Qualified Scheduling Entities based on load.	Low
Ancillary Services	Regulation	Unit charge on Load Serving Entities.	Low
	Reserve	Unit charge on Load Serving Entities.	Low
PJM			
Market Operator		Unit charges on transmission users.	Medium
Ancillary Services	Regulation	Unit charge on Load Serving Entities.	Low
	Primary Reserve	Unit charge on Load Serving Entitles.	Low
I-SEMS			
Market Operator		Part of TUoS tariff (unbundled) on transmission users (generators and loads).	Low
Ancillary Services	System Services	Part of TUoS tariff (unbundled) on transmission users (generators and loads).	Low

Service Category	Service	Cost Recovery Method	Causer-Pays Adherence
Great Britain			
Market Operator		Part of BSUoS Charge.	Low Uses beneficiary-pays principle. Allocated to customer's gross demand.
Ancillary Services		Part of BSUoS Charge.	Low Uses beneficiary-pays principle. Allocated to customer's gross demand.

Notes: (a) *Grid MWh – refers to electricity demand (net) that is met by large-scale Facilities that operate in wholesale electricity markets. Excludes 'behind-the-meter' generation or storage.*

(b) *Gross demand – Total electricity demand met by all generation in a system (includes behind-the-meter generation / storage). Also referred to as Gross MWh.*

Source: *Marsden Jacob 2022*

Marsden Jacob's make the following observations:

- Market Fees:
  - The NEM has made significant inroads to achieving causer-pays (included to more 'causers' of costs, such as network users and aggregators). However, the NEM still has a high dependence on Grid MWh charging, which is not a cost driver for AEMO fees.
  - The approach in the NEM falls short of Great Britain's approach to charge customers based on gross demand, which ensures that DER contributes to cost recovery. The Great Britain approach accepts that pricing of these market services is about cost recovery and not sending efficient price signals to change behaviour (i.e., to encourage transmission users to use less market services). On this basis, they conclude there are not good efficiency arguments for levying charges on Market Participants. Charges should simply be levied on ultimate beneficiaries of the service (i.e., final customers) or Gross MWh to reduce complexity and remove other distortions in the market.
- Regulation Services – the NEM uses a causer-pays methodology to determine contribution factors for allocating costs. This provides incentives for participants to reduce variability in generation and loads.
- Reserve Raise – both Singapore and the WEM use the runway methodology to allocate costs to generators, which is consistent with causer-pays approaches.
- Reserve Down – the WEM allocates costs to loads given that they are likely to be causer of the requirement for this cost (loss of load). However, the major causer of the requirements for this service are large industrial and commercial loads (i.e., loss of a large load which causes system frequency to rise rapidly), who would pay a higher proportion of costs under a causer-pays methodology, compared to smaller users.
- Inertia – the WEM has a formal unbundled RoCoF service which allocates costs to generators, loads and network operators (1/3 cost attribution for each customer class) which is consistent with the beneficiary-pays principle.

12. Implications of Jurisdictional Review

12.1 Energy Market Transformation

As highlighted in chapters 2 to 9, electricity markets around the globe are transforming as improvements in technology and government commitments to net zero emissions drive changes in the way that electricity is generated, transported, stored and used.

Electricity markets are transforming from a centralised system of large fossil fuel (coal and gas) generation towards a decentralised power system that include:

- installing intermittent generation sources, such as large-scale wind (onshore and offshore) and solar farms;
- installing grid connected storage Facilities (transmission and distribution connected) to firm power supplies from intermittent generation sources, including battery systems, pumped hydro and compressed air energy storage systems;
- installing 'behind-the-meter' resources or DER, including rooftop and ground mounted solar, battery systems and electric vehicles, which can also export power to the grid; and
- moving from single directional flow systems (i.e., generation, transmission, distribution and finally end use) to bidirectional flow systems (i.e., behind-the-meter solar array to grid and grid to home or business), which necessitates upgrades to networks to ensure the safe and secure supply of power.

Given that both electricity demand and supply will be more variable in the future due to the high penetration of intermittent plant, wholesale markets may have to become truly two-sided markets to ensure that both demand and supply can respond to price signals. If demand is not incentivised to reduce at peak times in electricity systems (such as EV or battery charging), then additional investment in dispatchable generation and storage will be required to maintain supply reliability, which may not be an efficient response.

One of the major consequences of this transformation is that behind-the-meter power supplies are making a significant contribution to meeting the total requirements of various electricity systems (i.e., WEM, NEM and CAISO). So much power is being produced and consumed behind-the-meter that the gap is increasing between gross or underling electricity demand (i.e., overall electricity demand by a community) and net or operational electricity demand (i.e., grid supplied electricity).

Traditionally, wholesale electricity markets were created to ensure the efficient dispatch of large-scale generation to meet grid demand. However, as behind-the-meter generation grows, it is becoming increasingly important to co-ordinate the dispatch of all types of generation and storage to meet gross demand.

Market mechanisms and associated supply and demand of various electricity services will increasingly have to accommodate both large-scale and small-scale systems. If the market mechanisms are expanded to accommodate most new supply sources, then this implies that funding sources for these services will also have to be expanded.

An electricity system which is dominated by intermittent generation and storage will have high fixed and low variable costs, so relying on future cost recovery based on principles of short run marginal cost or incremental energy costs could result in under-recovery of service costs. As a result, many wholesale electricity markets have converted from an 'energy-only' to an 'energy and capacity' design to ensure that adequate incentives are provided for the entry of high fixed cost plant (i.e., Great Britain, I-SEM).

This implies that unit charging ($/MWh) is going to become less important as a cost recovery mechanism for many services. This is the case if energy markets move away from a focus on grid electricity demand to gross electricity demand. As a result, it is likely that power systems will increasingly recover costs through charging practices based on capacity utilisation (kVA, kW), and the type of customer connection to power grids (i.e., single directional meter, bidirectional meter, voltage level etc.).

In essence, revenue from wholesale energy and ancillary service markets could decrease substantially in the future with high levels of renewable generation, with the result that capacity markets and out of market (i.e., contract for differences) mechanisms become the primary funding mechanism for participants in the future.

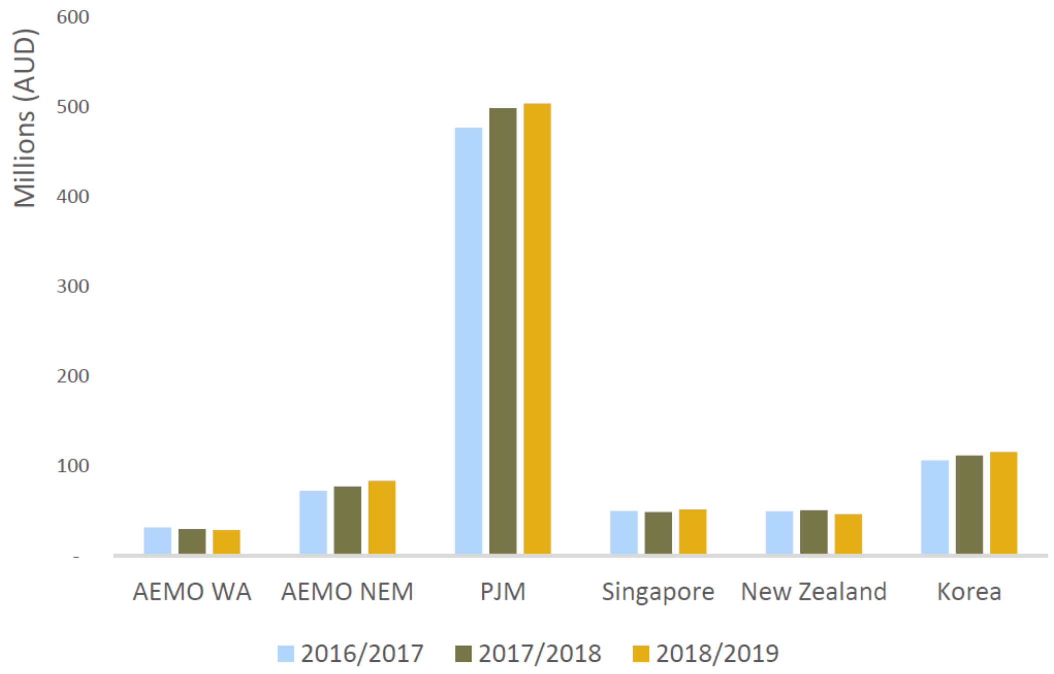
12.2 Allocating Costs for Market Services

12.2.1 Drivers for AEMO market and system costs

AEMO Market Fees, policy and regulatory costs are likely to be a function of the size of the market, the number of participants in that market, the number of products and services that are provided by the market and the relative complexity of the market.

There is a clear relationship between market size and the total cost of Market Fees across different markets as shown in Figure 14.

Figure 14: Total Market and System Operator Costs by Jurisdiction



Source: *The Lantau Group, Comparable Costs of Operating Electricity Markets in Different Jurisdictions, Prepared for Economic Regulation Authority, 12 June 2019, p.23.*

For example, AEMO's allowable revenue is $30.8 million for 2021/22 for market and system operator for the WEM with 17 TWh and 88 participants,[93] while the NEM has total allowable revenue of $125.4 million for 2021/22[94] (four times the WEM costs) serving 180 TWh and 504 participants (10 times the market size in terms of TWh and 5.7 times the number of participants). Given that the NEM costs are four times the WEM costs, there is reasonable correlation between costs and the number of participants (5.7 times WEM participants) in both the NEM and the WEM.

The ERA commissioned a consultant (The Lantau Group) to benchmark AEMO's market and system operator costs in 2019 and they highlighted the difference in costs (see Figure 14). The largest market (PJM 800 TWh, 1000 members) has the highest costs. PJMs total costs are 16 times AEMO's costs in the WEM, and the number of participants is 12 times the number of WEM participants, while energy traded is 47 times what is traded in the WEM. This suggests that the number of participants is a reasonable driver of total market and system costs, and energy traded does not explain total market or system costs.

Marsden Jacob's simple analysis of WEM costs, when compared to NEM and PJM costs, shows that overall market and system operator costs are likely to be more of a function of the number of participants, and not the amount of energy traded through the market. However, explaining differences in costs across jurisdictions on the basis of the number of participants is likely to have limited application.

Firstly, the market design and expected number of Market Participants would have impacted the original resource requirements for the market and system operator. Capital spent on market and system management systems, and even labour and materials required to manage the business would have been a function of the original market design, market rules, number of participants, complexity of the market and the amount of automation used by the Market Operator. Adding a Market Participant would likely have only a small impact on overall costs (i.e., costs associated with joining the market) and given that costs are essentially fixed, adding a new participant could actually reduce overall costs (and fees) for participation in the market.

Secondly, costs can vary due to differences in the maturity of a market (i.e., stable set of market rules and policies) and the relative complexity of the market. The WEM has been subject to a number of market reforms in recent years, which has contributed to significant increases in AEMO costs.

The ERA highlighted this in its draft decision on AEMO's Market Fees (Allowable Revenue 6 or AR6).[95] The ERA noted that increased funding was required to deliver WEM reform projects required under the Energy Transformation Strategy, which AEMO claimed resulted in a 50% increase in overall forecast capital expenditure – from $60.7 million to $91.2 million.

12.2.2 Determining Cost Pools and Billing Determinants

AEMO has taken this once step further in the NEM and attributed costs to each class of Market Participant based on an activity based costing approach (see section 3.3.5). Based on Market Participant interactions with its staff, AEMO has calculated proportions to allocate directly

93 Participants registered as of 19/05/2022

94 AEMO Electricity Revenue Requirement and Fee Schedule 2021-22

95 Economic Regulation Authority, Australian Energy Market Operator's allowable revenue and forecast capital expenditure proposal for the period 1 July 2022 to 30 June 2025, Draft determination, 31 March 2022, p. iii.

attributable costs to each participant type (i.e., Market Customer, network operator, wholesale participant). Non-attributable costs are then allocated to Market Customers.

Using activity based accounting practices to determine the allocation of costs to the type of user appears to be a reasonable basis for establishing a cost base for "Business As Usual" activities, provided that the levying of these costs does not deter market entry. The latter is unlikely given that costs are a small proportion of total entry costs for (say) a generating plant when compared to capital costs of equipment, network connection costs, financing, insurance and management costs.

Energy market reforms in many markets (i.e., the WEM, Great Britain and NEM) are in part caused by government policies' particularly policies to reduce carbon emissions. In the WEM and NEM, this includes direct subsidies to small-scale and large-scale renewable generation (i.e., Small-scale Renewable Energy Scheme and Large-scale Renewable Energy Target scheme). The increased penetration of intermittent generation technologies has contributed to the retirement of coal and gas fired units in the WEM and NEM and will contribute to the exit of dispatchable generation which provides a variety of services to the market (i.e., inertia, Frequency Regulation and Contingency Reserve etc.). In the WEM, changes to market rules to accommodate new technologies (e.g., Energy Storage Resources or ESR) and provide new services (e.g., RoCoF) have been required to maintain the reliability of supply and has increased AEMO costs to implement new products, services, systems and processes.

AEMO considered the use of gross metered data as a billing determinant for Market Fees in the NEM, and while it acknowledged that this may resolve the disadvantages of charging on a net basis (discrimination between customers with DER and those without), it rejected using gross metered data on the grounds that it is still allocating AEMO fixed costs using a variable billing determinant.[96] That is, it is sending a signal to customers to reduce power consumption when AEMO costs do not vary with power consumed. Despite this conclusion, AEMO continues to levy 50% of Market Customer costs on the basis of net grid consumption.

Ofgem has recommended that the recovery of both Market Fees and system services should be recovered on gross demand (see section 9.3). This will overcome the discrimination problem that has arisen with charging on the basis of net demand. However, moving to a billing determinant based on gross demand is problematic in the SWIS. Smart Metering has not been rolled out extensively, which means that the data on gross energy consumption or demand at each connection point (i.e., rooftop PV generation plus net grid demand) is not readily available. Estimates could only be ascertained using (for example) PV solar traces, installed capacity of PV systems behind-the-meter, and import meter demand.

However, Marsden Jacob's notes that AEMO Market Fees are only a small fraction of the total cost of delivered energy to the customer. It is likely that wholesale energy, capacity and ancillary service costs, environmental costs, network costs and retail margins and costs will have a much more significant impact on how much they pay for electricity services and any decisions a customer makes about energy use.

96 AEMO, Electricity Fee Structures, Final Report and Determination, A final report and determination on electricity fee structures to apply to Participant fees from 1 July 2021, March 2021, p.15.

12.2.3 Should Market Fees be recovered from Generators, Aggregators and Network Operators

Most markets recover Market Fees from wholesale Market Participants, whether they be transmission customers (PJM, ERCOT, I-SEM, Great Britain) or are Market Participants (WEM and NEM). This includes generators and LSEs.

If efficiency is the primary concern for the setting of Market Fees, then pricing is about sending a signal for a participant to optimise their use of the services provided by AEMO. The problem with this approach is that the setting of the fee is unlikely to change the future use of the market services given it is a relatively low charge relative to other costs. In addition, in certain instances, collaboration between network operators, AEMO, generators and aggregators should be encouraged to resolve the issues facing the industry.

If efficiency is not the primary concern, then the primary concern is cost recovery. Ofgem makes the following observation with regard to using prices for cost recovery purposes:

> *"it is not feasible to charge any of the components of balancing services in a more cost-reflective and forward-looking manner that would effectively influence user behaviour that would help the system and/or lower costs to customers. Therefore, the costs included within balancing services charges should all be treated on a cost-recovery basis."*[97]

This led the first Task Force on BSUoS charges (which includes Ancillary Services and Market Fees) to conclude that the purpose of BSUoS is cost-recovery and as such, it should be paid by final consumers (based on Gross MWh).

The Second BSUoS Task Force provided further rationale for this decision:

> *"Given BSUoS charges are cost recovery charges, it is not efficient to recover part of it via generation, because doing so means the costs are passed through into wholesale costs, which includes unnecessary risk premium and transaction costs."*[98]

It should be pointed out that the risks mainly related to the level of system services prices (e.g., regulation) and not ESO internal costs (National Grid costs). However, the point is still valid.

12.3 Causer-Pays applied to Essential System Services

Generators, aggregators and network operators all "cause" the requirement for Regulation, Reserve and inertia services, and can take actions to reduce the total cost of providing these services. These arguments are outlined below.

12.3.1 Recovery of Regulation Costs

The need for Regulation can arise due to the following:

- deviations between actual and forecast generation from intermittent generation sources;
- scheduled generators and scheduled loads deviating from dispatch targets, other than in response to a frequency deviation;

97 http://www.chargingfutures.com/media/1330/balancing-services-charges-task-force-draft-report.pdf

98 http://www.chargingfutures.com/media/1477/second-balancing-services-charges-task-force-final-report.pdf

- differences between aggregated customer load profiles and generator ramping profiles within a dispatch interval; and
- load forecast errors, which can include unexpected variations in the output of DER.

In the NEM, AEMO enables Regulation FCAS to either raise or lower system frequency to counteract small changes in power system frequency. Once enabled, Regulation FCAS is deployed as needed by Automatic Governor Control (AGC) based on the detected system frequency and accumulated time error of the system.[99]

Contribution Factors are determined to apportion the costs of Regulation FCAS to Market Participants (i.e., Generators, Customers and Small Generation Aggregators) based on the assessed contribution of plant/load at their connection points to recent variations in system frequency causing the need for Regulation FCAS.[100]

The calculations for Contribution Factors assess deviations from a reference trajectory for each area, which is derived from expected dispatch or expected MW consumption. The deviations are calculated every four seconds and averaged over a dispatch Trading Interval (5 minutes).

The Contribution Factors are calculated for an area basis and then normalised to produce NEM Contribution Factors for individual Market Participants (generators) based on their net performance, with residual demand Contribution Factors then calculated for Market Customers.

The purpose of these Contribution Factors is to attribute costs to parties that are responsible for frequency deviations and to provide incentives for them to change their behaviour to reduce regulation costs. This could include investment in better forecasting systems, co-locating storage Facilities to smooth out variations in renewable plant output, or use of storage to manage variations in loads.

FCAS market prices and Contribution Factors provide a strong signal for Market Participants (i.e., generation and loads) to reduce frequency deviations and provides potential efficiency benefits for the market.

In the WEM, it is proposed that costs be recovered from generation and loads based on their overall generation or consumption (Grid MWh). This practice is not consistent with causer-pays methodology. For example, Grid MWh may reduce because of increased DER, while at the same time increasing variations in load MWh and giving rise to increased Regulation services.

In Marsden Jacob's view, a causer-pays methodology, similar to the Contribution Factors used in the NEM, should be applied and each user type charged on the basis of the following:

- Intermittent generators according to their deviation from forecast;
- Scheduled generators according to deviation from dispatch; and
- Loads according to their volatility.

99 AEMO, Regulation FCAS Contribution Factor Procedure, Determination of Contribution Factors for Regulation FCAS Cost Recovery, 2 December 2018, p.7.

100 Ibid.

12.3.2 Contingency Reserve Raise

Contingency Reserve Raise is required to cover a material decrease in power system frequency due to a generation Facility tripping or loss of network assets or increase in demand by a major load (loss of onsite generation).

Both the WEM and NEMS have adopted a modified runway method to attribute costs to generators to ensure they are incentivised to minimise the requirement for this service. As outlined in section 2.5, a higher proportion of Contingency Reserve costs in a Trading Interval will be allocated to the largest generator in the WEM, which provides incentives for participants to dispatch smaller generators to minimise these costs.

For network risks, the runway method will be applied from all energy producing Facilities that would be disconnected because of a network outage (that is, the relevant lines disconnecting). The magnitude of the network component reflects the delta between the Largest Network Risk and the Largest Facility Risk.

Behind-the-meter generation also contributes to the need for Contingency Reserve Raise. If a behind-the-meter generator trips without a matching reduction in behind-the-meter load, the Facility is relying on the Contingency Reserve Raise held by the market to maintain secure operation. Proposed arrangements do not allow full recovery from these Facilities.

12.3.3 Contingency Reserve Lower

Contingency Reserve Lower is required to cover the risk of a material decrease in system frequency due to a loss of load(s), which can arise due to either a network outage or individual load facility outage. Ultimately, the loss of a single large load, or the loss of numerous loads on single network element, are the causers of the Contingency Reserve Lower service requirement.

Contingency Reserve Lower costs will be recovered from loads based on their share of consumption in the Trading Interval. This is consistent with the current cost allocation method for Load Rejection Reserve.

However, this approach is inconsistent with the causer-pays principle. The requirements for this service are a function of the loss of large industrial or commercial loads that are in a retailers' portfolio, not Grid MWh consumed. The requirement for Contingency Reserve Lower is a function of the size of the potential load that may be lost, in a similar way that the largest generator is the cause of the requirement for Contingency Reserve Raise. A causer-pays approach, and consistency with the methodology used for Contingency Reserve Raise, would suggest that a modified 'runway method' could be applied to allocate Contingency Reserve Lower costs to the largest loads operating in a Trading Interval.

To minimise the charge, the customer could stipulate that if they lose behind-the-meter generation, then they will also reduce load (demand management) to minimise using system reserves which are required for the next generator or network failure. Alternatively, or in addition, the load could install a behind-the-meter better to cover the loss of behind-the-meter generation for a short period.

12.3.4 RoCoF

As outlined in section 2.5.4, RoCoF is a new service that is required because of the loss of synchronous generation on the power system and the need to encourage generators and network operators to improve their ride-through capability, and to reduce their exposure to the costs of the

RoCoF Control service. Potentially, large industrial and commercial loads can also benefit from improved ride-through capability.

While generators, network Facilities and large-customers are not the causers of low inertia, they will benefit from improved ride-through capability. If these parties improve their ride-through capability, then smaller loads (i.e., residential and small and medium businesses) may ultimately become the only remaining reason for the RoCoF Control service. Given that smaller loads will ultimately be the beneficiary of the service, it could be argued that they should bear some of the cost of the service.

Under the Amending Rules that will commence with the start of the new market in October 2023, generators, loads and Western Power will be allocated RoCoF charges (1/3 each). This cost allocation methodology is consistent with the causer/beneficiary-pays principle. The cost allocation methodology could be improved if charges were more closely related to the benefits that each participant type would receive by improving ride-through capability.

The method for RoCoF cost recovery method is out of scope for this review.

12.3.5 System Restart Service

System Restart Service (or Black Start Service) are required to restore electricity supplies after multiple cascading failures in the electricity system. It is unlikely that any one generator or load entities would be responsible for a system wide shut down. Setting charges to generators or load entities would not likely reduce the likelihood of a system wide black-out.

The pricing of System Restart Service is not primarily about market efficiency, it is primarily about cost recovery and as a result, the cost of System Restart Service should be borne by loads. An appropriate billing attribute would be a connection cost or a combination of connection cost and grid MWh (the same as for Market Fees).

12.3.6 Non-co-optimised ESS – Voltage Control and Transient and Oscillatory Stability

While not specified in the WEM, non-co-optimised ESS are typically locational services used to substitute for network upgrades. This is likely to be similar to NSCAS in the NEM, which includes controlling voltages and power flow across network elements and maintain transient and oscillatory stability within the power system following major power system events.

The causers are both loads requiring power to be supplied and generators providing the power, and any transmission issues that require such services. Often these services are provided under network support contracts with the transmission entity (which may be a substitute for network investments).

In the WEM, these services can be procured by either Western Power or AEMO. Where Western Power procures a NCESS contract, it will recover the costs of the NCESS through its network tariffs. Where AEMO procures a NCESS contract, costs will be recovered from all Market Participants that have a consumption share over the period of that service.

12.3.7 Fast Frequency Response

FFR services are required because at various times the level of inertia in a power system is low (due to high levels of non-synchronous generation in operation) and deviations in frequency need to be acted upon more rapidly to avoid significant changes in system frequency and avoid the shutdown of generation Facilities and equipment.

Like the requirement for RoCoF, the primary causer of the need for this service is the level of non-synchronous generation that becomes connected to a system. However, the actual FFR is only required if a generator deviates from its target generation level, or a major customer varies its demand. Hence, the secondary causer of this service is the same as the requirement for Contingency Reserve services (Raise and Lower).

Appendix A. Mapping of Market Services and Essential System Services in Each Jurisdiction to WEM Service Equivalents

WEM	NEM	NEMS	CAISO	ERCOT	PJM	I-SEM	GB (Transgrid)
Market and System Services (Fee)							
AEMO Market Services	NEM Service	EMC Service	Grid Management	System Administration	Control Area Administration Market Support Service	Transmission System Operator (TSO)	Electricity System Operator (ESO) Internal
System Operation							
Frequency Control Essential System Services (typically co-optimised with Energy Market)							
Frequency Regulation Raise	FCAS Regulation Raise	Regulation	Regulation Up	Regulation Up	Regulation	Synchronous Inertial Response Fast Frequency Response (FFR)	Response
Frequency Regulation Lower	FCAS Regulation Lower		Regulation Down	Regulation Down			
Contingency Reserve Raise	Contingency FCAS Raise	Reserve	Spinning Reserve Non-Spinning Reserve	Responsive Reserve Non-Spinning Reserve	Primary Reserve: • Synchronised • Non-Synchronised Day Ahead Scheduling Reserve	Primary Operating Reserve Secondary Operating Reserve Tertiary Operating Reserve	Fast Reserve Operating Reserve Short Term Operating Reserve
Contingency Reserve Lower	Contingency FCAS Lower						
RoCoF	There are service equivalents but not provided as unbundled service with itemised charge						Bundled into BSUoS
Other Essential System Services (not co-optimised with energy market)							
System Restart Services	System Restart Ancillary Service	System Restart capability	System Restart Service	System Restart Services	System Restart Service	System Restart	System Restart
NCESS	Network Support and Control Ancillary Services	Reactive Support and Voltage Control Service	Voltage Support	Voltage Support	Reactive Service and Voltage Control	Steady State Reactive Power	Reactive Constraint (Voltage)

WEM	NEM	NEMS	CAISO	ERCOT	PJM	I-SEM	GB (Transgrid)
NCESS Fast Frequency Response (Transitional)	Co-optimised Ancillary Service Fast Frequency Response				Incorporated into existing regulation service category		Fast Frequency Response Services: • Dynamic Containment • Dynamic Moderation • Dynamic Regulation

Appendix B. Market Fees and Ancillary Services Recovery by Jurisdiction

	WEM	NEM	NEMS	ERCOT	PJM	CAISO	I-SEMS	Great Britain
Market Characteristics								
Market Design	Energy and Capacity Compulsory net pool Co-optimisation of Energy and ESS commences October 2023	Energy Only Compulsory gross pool Co-optimisation of FCAS and Energy	Energy Only Co-optimisation of energy, regulation and reserve	Energy-Only Co-optimised energy and Ancillary Services market (day ahead)	Energy and Capacity Co-optimised energy and Ancillary Services	Energy Only. Nodal pricing. Co-optimisation of energy and Ancillary Services	Energy and Capacity Gross pool	Energy and Capacity
Demand and Plant Portfolio (exceeds 5% of total capacity installed)	Peak Demand 4.5 GW Grid Consumption 17 TWh Coal, gas and wind	Peak Demand 40 GW Grid Consumption 180 TWh Coal, gas, hydro, wind and solar	Peak Demand 5.8 GW Grid Consumption 50.7 TWh Gas	Peak Demand 74.8 GW Grid Consumption 382 TWh Gas, wind coal and nuclear	Peak Demand 149 GW Grid Demand 800 TWh Coal, gas, nuclear hydro and wind	Peak Demand 47 GW Grid Consumption 212 TWh Gas, hydro, wind solar and nuclear	Peak Demand 5 GW Grid Consumption 31 TWh Gas, wind and coal.	Peak Demand 50 GW Grid Consumption 330 TWh Gas, wind, nuclear, imports and biomass.
Emission Reduction Targets	Commonwealth and State target of zero net emissions by 2050	State based renewable energy targets (e.g., 50% renewables by 2030) Commonwealth target of zero net emissions by 2050	Halve emissions by 2050 (i.e., achieve 33 MtCO2e)	No state based target	Impacted by the emission targets of 13 states covered by PJM	By 2030 at least 60 percent of California's electricity is renewable By 2045, all electricity produced is from renewable and zero-carbon resources	Emission reduction of 51% by 2030 Net-zero greenhouse gas emissions no later than 2050	Net zero emissions by 2050

	WEM	NEM	NEMS	ERCOT	PJM	CAISO	I-SEMS	Great Britain
Market Fee Cost Recovery								
Market Operator	Loads and Generators (Grid MWh)	Loads (Grid MWh) and Generators (Grid MWh/Capacity MW)	Fixed ($/participant) and variable charges ($/MWh) for Market Participants	ERCOT is funded by a fee that is charged to Market Participants based off the load they serve (Grid MWh). ERCOT's System Administration Fee currently is set at $0.55/MWh.	To transmission customers: Control Area Administration Charge - $/MWh (grid) Market Service Support Charge - $/MWh (grid) $/bid offer segment	Charges on participants in Grid MWh of supply and demand excluding Transmission Ownership Rights (TORs)	Incorporated into a TUOS tariff that is levied to generators, suppliers and autoproducers ($/MWh) charged by SEMO	Currently levied on wholesale generators, suppliers (retailers) and directly connected transmission customers (Grid MWh) Will be incorporated into a single Balancing Service Use of System (BSUoS) charge and levied on final customers (gross MWh) from 2023
System Operator	Loads and Generators (Grid MWh)	Loads (Grid MWh) and Generators (Grid MWh/ Capacity MW)	As above	As above	As above	As above	As above	Part of BSUoS
Essential System Service Cost Recovery								
Regulation Raise	Load and non-scheduled generation (Grid MWh)	Causer-pays method for load, scheduled and non-scheduled generators (Grid MWh)	Loads (Grid MWh)	Charged to Load Serving Entities based upon a proration determined by load share	Bundled charge on Load Serving Entities share of total load (grid MWh)	Bundled charge on Load Serving Entities in proportion to their actual load in the system	Incorporated into TUOS tariff	Part of BSUoS
Regulation Lower	Load and non-scheduled generation (Grid MWh)	Causer-pays method for load, scheduled and non-scheduled generators (Grid MWh)	Loads (Grid MWh).	As above	Bundled charge on Load Serving Entities share of total load (grid MWh)	Part of bundled charge on Load Serving Entities	Incorporated into TUOS tariff	Part of BSUoS

	WEM	NEM	NEMS	ERCOT	PJM	CAISO	I-SEMS	Great Britain
Contingency Reserve Raise	Allocated to wholesale generators using runway method (Grid MWh)	All Market Generators (Grid MWh)	Generation based on a "runway" model method. Higher cost allocation to larger Facilities and those with poor reliability.	As above	Bundled charge on Load Serving Entities share of total load (grid MWh)	Part of bundled charge on Load Serving Entities	Incorporated into TUOS tariff	Part of BSUoS
Contingency Reserve Lower	Allocated to loads based on Grid MWh consumed	Loads (Grid MWh)	Generation based on a "runway" model method. Higher cost allocation to larger Facilities and those with poor reliability	As above	Bundled charge on Load Serving Entities share of total load (grid MWh)	Part of bundled charge on Load Serving Entities	Incorporated into TUOS tariff	Part of BSUoS
Inertia Services	Minimum inertia costs allocated to generators, loads and network operations equally (1/3)						Incorporated into TUOS tariff	
Other ESS								
Network Control Services (include voltage support)	Network operator via network tariffs (from 2022)	NSCAS payments are recovered fully from loads				Part of bundled charge on LSE	Incorporated into TUOS tariff	Part of BSUoS
System Restart Service	Loads (Grid MWh)	SRAS payments are recovered from both customers and generators on a 50/50 basis.				Part of bundled charge on LSE	Incorporated into TUOS tariff	Part of BSUoS

	WEM	NEM	NEMS	ERCOT	PJM	CAISO	I-SEMS	Great Britain
Future State								
Key system challenges	High penetration of DER Static grid demand (MWh) Minimum generation Ramping to meet demand Loss of inertia Lack of long term energy storage	High penetration of DER Static grid demand (MWh) Minimum generation Ramping to meet demand Loss of inertia	Level-playing field for all technologies Clarity on role of Forward Capacity Mechanism and the real-time energy markets; Integration of DER in wholesale markets	Maintaining reliability in winter storm events High price variability (including Ancillary Services)	Current flaw in frequency regulation market resulting in battery providing fast ramping services and becoming depleted which causes the battery to recharge when demand is increasing rapidly. Proposed amendments have been rejected by FERC	DER 40% of total capacity by 2040 Installed capacity will have to increase by three-fold by 2045 to achieve the 2045 goal (due to electrification and renewable target) More “operational flexibility” from resources to reliably serve loads as the resource mix evolves to include more VRE resources	With renewable energy making up a larger portion of the generation mix, the electricity grid has seen an increase in the quantum and variability of the costs associated with system services	Decarbonisation will greatly increase electricity demand Significant investment in renewables and firming capacity Capturing the value of flexibility

	WEM	NEM	NEMS	ERCOT	PJM	CAISO	I-SEMS	Great Britain
Proposed Reforms								
Market Fees		Expanded to include recovery from network operators Levy on loads will be based on both Grid MWh and number of connections (NMIs)						
ESS regulation / reserve		Introduce fast start contingency services in the future		Senate Bill 3 requires intermittent generation (wind and solar) to buy Ancillary Services and replacement power sufficient to manage net load variability Limits the price of Ancillary Services to 150% of any High System wide Offer Cap (HCAP) or emergency pricing		New day-ahead ancillary service product called an imbalance reserve that would ensure sufficient real-time dispatch capability to meet net load imbalances that arise in between the day-ahead and real-time markets	Currently considering alternative options for the recovery of system services charges based on beneficiary and causer-pays principles	
Other market reforms	5-minute market settlement in 2025	Develop a Resource Adequacy Mechanism		Fast Frequency Response		FERC approved ramp capability product		

Government of **Western Australia**
Department of **Mines, Industry Regulation and Safety**
Energy Policy WA

Energy Policy WA
Level 1, 66 St Georges Terrace, Perth WA 6000
Locked Bag 100, East Perth WA 6892
Telephone: 08 6551 4600
www.energy.wa.gov.au

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