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ENERGY POLICY WA

Reserve Capacity Mechanism Review – International Review

31 March 2022

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Document version: 1.0

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Executive Summary

This report is prepared for Energy Policy WA (EPWA) as part of its review of the Wholesale Electricity Market (WEM) Reserve Capacity Mechanism (RCM). In this report, we review capacity mechanism arrangements in six markets that have relevance to the WA context and draw out examples and lessons that may be applicable in formulating the new WEM Rules for the RCM, with a focus on identifying:

- Issues the capacity mechanism aims to address;
- Issues the mechanism is facing or is expected to face in the future;
- Potential solutions to those issues; and
- How these issues relate to the WEM.

The markets reviewed for the purpose of this study are:

- Pennsylvania, New Jersey, and Maryland Regional Transmission Organization (PJM RTO);
- New England Independent System Operator (ISO-NE);
- France;
- Colombia;
- UK; and
- Ireland.

These markets – like the WEM – all have quantity-based, market-wide capacity mechanisms with centralised and decentralised features.

We identified five key themes:

- Capacity market settings can work against decarbonisation;
- An effective reliability criterion must consider different dimensions of unserved energy;
- Alternative methods for certifying capacity are available;
- A diverse supply mix is a more reliable supply mix; and
- The WEM demand curve is shallower than the demand curve in other jurisdictions.

We also identified several other design features for consideration in later stages of the RCM review.

Capacity market settings can work against decarbonisation

The WEM is amid transition from predominantly grid-connected, fossil-fuelled generation to distributed renewable generation. The WA government has expressed a goal of being net carbon neutral by 2050. To achieve this goal, the WA Government has announced the closure of the Collie Power station in late-2027 and the Muja D Power Station in late-2029, and the energy sector transition must continue. As a key revenue stream for new and existing generation facilities, the RCM must, at minimum, not hinder decarbonisation of the electricity sector, and could play a significant role in supporting decarbonisation.

While all the markets studied are also working to increase renewable generation, several have faced challenges where the design of the capacity mechanism has hindered this goal.

In the WEM, as in other markets, capacity payments generally act to extend the life of existing facilities. Because the incumbent WEM generation fleet receiving capacity payments is primarily fossil-fuelled, this has potential to temper the competitiveness of new renewable capacity in the South West Interconnected System (SWIS). Although new resources can still enter the WEM to provide energy and ancillary services without entering the capacity market, it will take longer to recover the capital cost of their resource, potentially delaying the transition.

Key points

- The review will need to look closely at the impact of capacity payments on the viability of renewable generators.
- The UK experience shows that the WEM should consider emissions parameters for capacity eligibility.

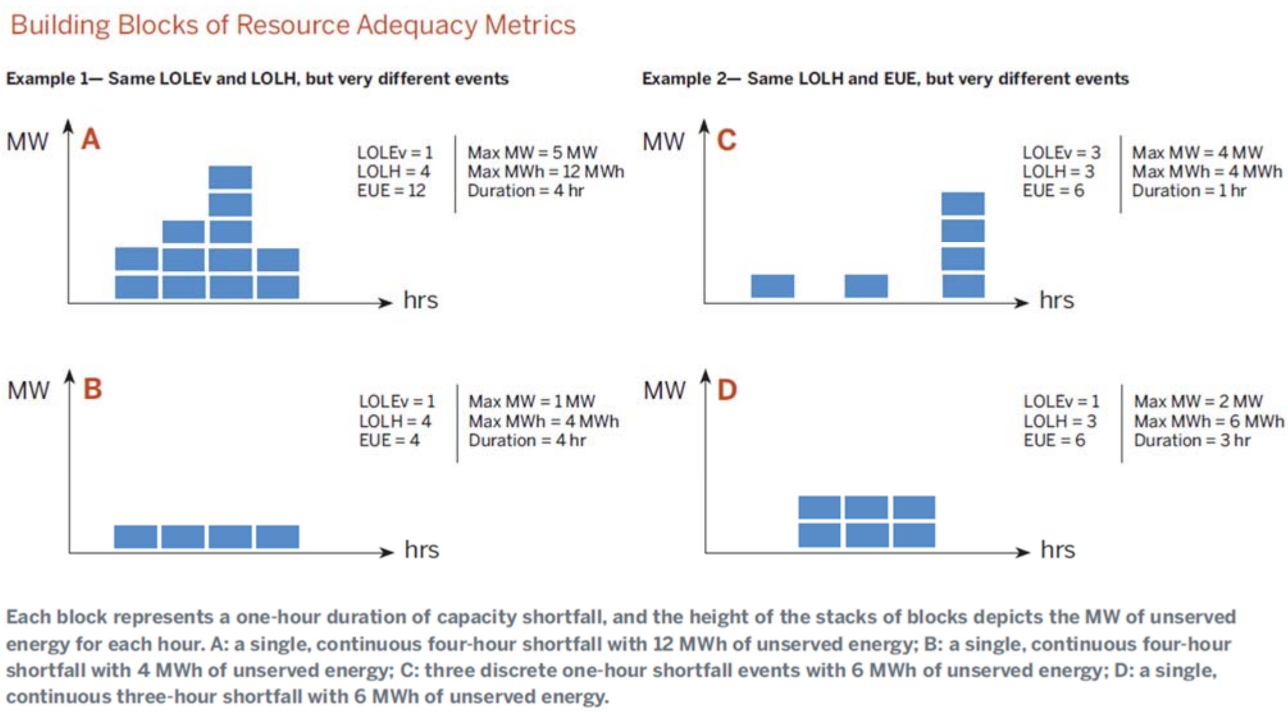
An effective reliability criterion must consider different dimensions of unserved energy

In most power systems, the risk of unserved energy has historically been highest at times of peak demand. Consequently, reliability criteria have largely sought to provide sufficient capacity to meet peak demand.

This made sense when the generation fleet was primarily traditional thermal generation, but as the proportion of intermittent renewables increases, the risk profile is changing, with increased risk of unserved energy in hours outside the peak period.

A 2021 paper by the US research organisation Energy Systems Integration Group[1] included Figure 1Figure 19, providing examples of different types of reliability events, highlighting the different types of outages that may need to be accounted for.

Figure 1: Dimensions of resource adequacy[2]



Key points

- Reliability criteria elsewhere all focus on unserved energy, none include mechanisms to deal with low load conditions.
- The WEM reliability criterion is already more flexible than other markets studied, with two limbs, each addressing a different dimension of unserved energy.
- The system stress modelling conducted as part of the RCM review will inform the type of events to be expected in the WEM, and hence which event dimensions are most important.

[1] https://www.esig.energy/resource-adequacy-for-modern-power-systems/

[2] Redefining Resource Adequacy for Modern Power Systems - Energy Systems integration group

ALTERNATIVE METHODS FOR CERTIFYING CAPACITY ARE AVAILABLE

Different markets use different methods to determine the reliability contribution of eligible resources, with different approaches for different technologies.

The studied markets provide some useful examples of methods different from those currently used in the WEM. In particular, PJM and the UK use probabilistic modelling to assess the incremental benefits to reliability of a given intermittent generator, and ISO-NE is considering a similar approach to account for conventional thermal power plants with slow ramp rates and long start-up times.

This aligns with the recommendation from the Economic Regulation Authority's (ERA) recent review of the WEM's relevant level methodology[3], to develop of a numerical model to better assess the contribution of renewable resources in the SWIS and the ERA's subsequent Rule Change Proposal followed by the Rule Change Panel's Draft Rule Change Report.[4]

Key points

- Other markets are already using probabilistic methods to better assess the contribution of intermittent resources to system reliability.
- A model-based method could potentially be extended to other types of resources, providing a single capacity assessment methodology for all resource types.

A DIVERSE SUPPLY MIX IS A MORE RELIABLE SUPPLY MIX

Several markets studied had issues arising from heavy reliance on a single resource type. This is not solely attributable to capacity mechanism design, but as a major revenue stream, capacity payments have the potential to help or hinder a diverse supply mix.

In the year to July 2022 in the WEM, coal generation provided 37% of electricity supplied, gas 29%, wind 18%, distributed solar 14% and utility solar 2%. The system will become even more reliant on gas generation as the main firming resource, and as the 2050 net zero target approaches, gas fired capacity can also be expected to exit, with intermittent resources becoming the overwhelming source of energy.

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[3] Review of method used to assign capacity to intermittent generators 2018, section 6.

[4] The Rule Change Proposal and the Draft Rule Change Report are published on the Coordinator's website: Rule Change RC_2019_03 (www.wa.gov.au). See section 4.1.2 of the Draft Rule Change Report.

Key points

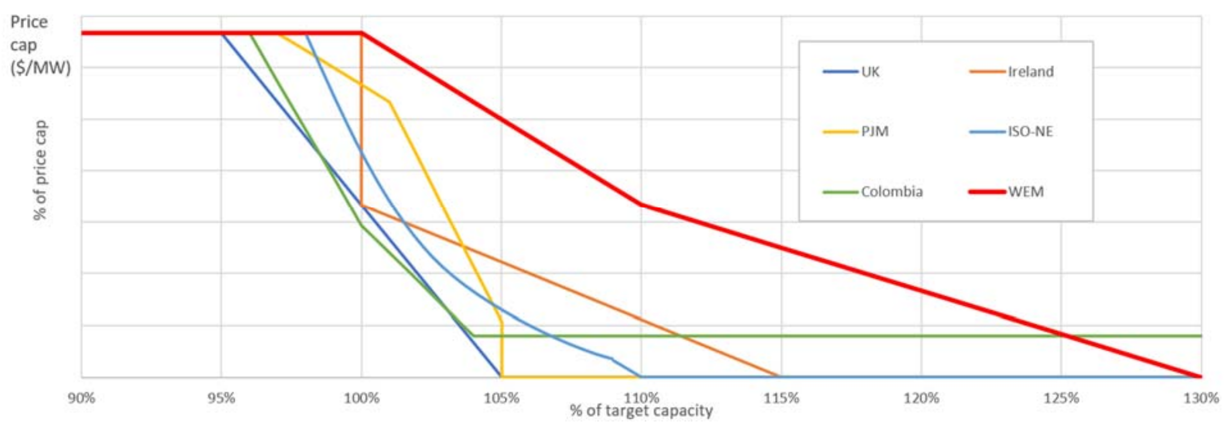
- The small size and lack of interconnection of the SWIS means that the retirement of a single large generator has significant impact on the reserve margin, and hence system reliability.
- The RCM must be able to support entry of new capacity to replace the facilities exiting the market and to manage evolving market conditions, while remaining technology neutral (to renewables, storage, aggregated distributed resources, clean thermal[5] etc.).

THE WEM DEMAND CURVE IS SHALLOWER THAN OTHER JURISDICTIONS

The method of setting the Benchmark Reserve Capacity Price (BRCP) is explicitly in scope of the RCM Review project. The remainder of the pricing regime is out of scope, including the demand curve, the fixed price option, and the refund regime (except for consequential changes required by changes to the in scope items).

The WEM demand curve is a relative outlier compared to the jurisdictions reviewed, though their price curves are used to define the demand in capacity auctions rather than in administered price regime. Figure 2 shows the various demand curves.

Figure 2: Demand curves in selected capacity mechanisms



[5] Clean thermal includes facilities such as green hydrogen or oxy-fuel combustors which produce zero direct emissions.

All markets use a benchmark value to calibrate the demand curve, based on the gross or net cost of new entry (CONE) for a specific new entrant resource.

The CONE is the capital investment costs for the facility, plus the operational and maintenance expenses for the first year of operation.

Net CONE is the CONE less an estimate of the contribution of energy and ancillary services revenues towards capital costs. These are the inframarginal rents, or profits from supplying market services at a profit. This measure assumes that the marginal new entrant would receive some contribution to capital costs from the energy and essential system services markets.

Key points

- There is no consensus on whether CONE or Net CONE is a more appropriate benchmark.
- All markets studied use gas fired generation as the expected marginal new entrant technology.

OTHER DESIGN FEATURES

In addition to the five issues above, we noted a variety of other design features that differ from the WEM approach.

Key points

- PJM has an option for participants to opt out of the capacity mechanism by demonstrating they can meet their own load. This may not be appropriate for the WEM due to the need to allocate costs of capacity credits acquired by AEMO in excess of the reserve capacity requirement.
- A decentralised resource adequacy assessment, as used in France, would require a more complex arrangement if applied to multiple types of system stress,
- Dedicated financial support for specific types of technology is provided separately from the capacity mechanism (for example, renewable subsidies are not part of the capacity mechanism in Ireland, PJM, and ISO-NE, and there is a separate procurement arrangements for storage capacity in France).
- Facility temperature dependence at low temperatures is unlikely to be relevant in the WEM as winter temperatures in the SWIS are unlikely to be low enough to affect facility performance, and peak system demand is expected to continue to be

experienced in summer, even as winter demand increases relative to summer demand.

- Alternatives to the WEM's 'all hours' availability obligation for scheduled facilities could dilute the capacity assurance provided by current WEM settings.
- Penalty payments could be distributed to owners of facilities that over-performed obligations during system stress events, rather than to all holders of capacity.

NEXT STEPS

The lessons from international markets will inform later stages of the RCM review, and in particular, the options for the reliability criterion and the options for certifying capacity contribution of each facility.

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Glossary of Terms

Term	Description
ACR	Avoidable Cost Rate
AEMO	Australian Energy Market Operator
BRA	Base Residual Auction
BRCP	Benchmark Reserve Capacity Price
CAISO	California ISO
CCGT	Combined Cycle Gas Turbine
CCR	Capacity Credit Rights
CfD	Contract for Differences
CONE	Cost of New Entry
CRE	Energy Regulation Commission (in French)
CREG	Commission for the Regulation of Energy and Gas
CRM	Capacity Remuneration Mechanism
CRU	Commission of Regulation of Utilities
CSO	Capacity Supply Obligation
CT	Combustion Turbine
DSP	Demand Side Programme
DSR	Demand Side Response
E&AS	Energy and Ancillary Services
EDF	Électricité de France
EE	Energy Efficiency
ELCC	Effective Load Carrying Capability
EMR	Electricity Market Reform
ENFICC	Firm Energy for Reliability Charge (in Spanish)
ENTSO-E	Europe wide European Network of Transmission System Operators

EOM	Energy-Only-Markets
EPWA	Energy Policy WA
ERA	Economic Regulation Authority
ESO	Electricity System Operator
ESR	Electric Storage Resources
ESS	Essential System Services
EUE	Expected Unserved Energy
FCA	Forward Capacity Auction
FCESS	Frequency Controlled Essential System Services
FCM	Forward Capacity Market
FPR	Forecast Pool Requirement
FRR	Fixed Resource Requirement
ICAP	Installed Capacity
IRCR	Individual Reserve Capacity Requirement
I-SEM	Integrated Single Electricity Market
LDA	Locational Deliverability Areas
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LOLP	Loss of Load Probability
LSE	Load Serving Entities
MEM	Wholesale Energy Market (in Spanish)
MOPR	Minimum Offer Price Rule
MRI	Marginal Reliability Index
NAQ	Network Access Quantity
NBP	Net-Bilateral Position
NCP	Net-Contract Position
ISO-NE	New England Independent System Operator

NEM	National Electricity Market
NERC	North American Electric Reliability Council
NG	Natural Gas
OCGT	Open Cycle Gas Turbines
OEF	Compliance Of Obligation (in Spanish)
Ofgem	Office of Gas and Electricity Markets
PJM RTO	Pennsylvania, New Jersey, and Maryland Regional Transmission Organization
POE	Probability of Exceedance
RCM	Reserve Capacity Mechanism
RCOQ	Reserve Capacity Obligation Quantity
RCP	Reserve Capacity Price
RLM	Relevant Level Methodology
RoCoF	Rate of Change of Frequency
RPM	Reliability Pricing Model
RTE	Réseau de Transport d'Electricité
RTM	Real-Time Market
SEM-O	Single Electricity Market Operator
SESSM	Supplementary Services System Mechanism
SIN	National Interconnected System (in Spanish)
SONI	System Operator Northern Ireland
SSPD	Superintendence of Public and Domiciliary (household) Services
STEM	Short Term Energy Market
SWIS	South West Interconnected Systems
TNUoS	Transmission Network Use of System
ToR	Terms of Reference
UCAP	Unforced Capacity

VoLL	Value of Lost Load
VRR	Variable Resource Requirement
WEM	Wholesale Electricity Market
XM	Compañía de Expertos en Mercados SA

1 INTRODUCTION

1.1 PURPOSE OF THIS REPORT

The WEM comprises several complementary mechanisms that together are designed to ensure secure, reliable, and affordable supply of electricity to consumers in the SWIS.

The Short-Term Energy Market (STEM) and the Balancing and Load Following Markets (to be replaced by the Real Time Market in 2023) are the mechanisms for short term optimisation of the generation fleet. Long term signals for capacity investment are provided through the RCM.

The Coordinator of Energy (the Coordinator) is currently reviewing aspects of the RCM in consultation with the Market Advisory Committee's (MAC) Reserve Capacity Mechanism Review Working Group (RCMRWG).

This paper provides an overview of capacity mechanisms in other jurisdictions, with a focus on identifying:

- Issues the capacity mechanisms aim to address;
- Issues the mechanisms are facing or are expected to face in the future;
- Potential solutions to those issues; and
- How these issues relate to the WEM.

In this report, we review the capacity mechanism arrangements in six markets that have relevance to the WA context and draw out examples and lessons that may be applicable in formulating the new RCM for the WEM.

1.2 STRUCTURE OF THIS REPORT

The report is structured as follows:

- Section 2 provides a brief introduction to the rationale for reserve capacity mechanisms, and various approaches used around the world.
- Section 3 reviews the capacity arrangements in six jurisdictions, the issues they face, and methods used to address them.
- Section 4 summarises key themes, and how they inform the WEM RCM review.
- Appendix A provides an overview of the WEM.
- Appendix B provides a comparative summary of the market design of the jurisdictions under consideration.

2 Introduction to approaches for ensuring resource adequacy

This chapter provides an overview of market design approaches used around the world, how they signal the need for new investment, and how they attempt to ensure capacity is available at times of system stress.

- Section 2.1 discusses markets which pay only for energy supply.
- Section 2.2 provides an overview of different approaches to procuring and providing reserve capacity.
- Section 2.3 covers key aspects of a quantity-based, market-wide procurement mechanism, such as the WEM RCM, and the capacity mechanisms used in the markets studied for this review.

2.1 Energy only markets

Not all modern electricity markets have a capacity mechanism. For example, New Zealand, Singapore, Alberta, and ERCOT are all 'energy only markets' (EOM), where market processes facilitate real-time and/or day-ahead provision of energy and essential system services, but there is no explicit payment mechanism to ensure facilities will be available in real time. The National Electricity Market (NEM) in eastern Australia is currently an EOM but is expected to implement a capacity mechanism in the next few years.

In a competitive EOM, facilities will generally price their market offers to ensure they recover variable costs, with capital costs only recovered in periods where the market price rises above a facility's short-run marginal cost. While the baseload facilities will have much of their output contracted by retailers, infrequent periods of very high prices are needed to allow seldom-dispatched facilities to cover their capital costs. High energy prices indicate a need for additional generation and signal the market to invest.

If market price caps are set at modest levels to protect consumers from generators that can take advantage of market power and to avoid volatility, peaking facilities (which may operate for only a few hours each year) may be unable to earn adequate revenue to recover their costs. Further, with increasing penetration of intermittent renewable generation in the global generation fleet, real-time energy prices will fall, as the short run marginal cost of intermittent renewables is near zero. This dampens the wholesale prices and affects the pricing signal for investments. Finally, uncertainty around the timing, duration, and frequency of high spot prices increases the risk for developers seeking finance for new investment, and there is no explicit guarantee that sufficient generation will be available to meet peak system load, particularly in an abnormally high demand scenario.

For these reasons, many electricity markets go beyond the energy only model to incorporate an explicit mechanism to compensate participants for having 'iron in the ground' which can operate, even if it seldom or never does.

2.2 Capacity mechanisms

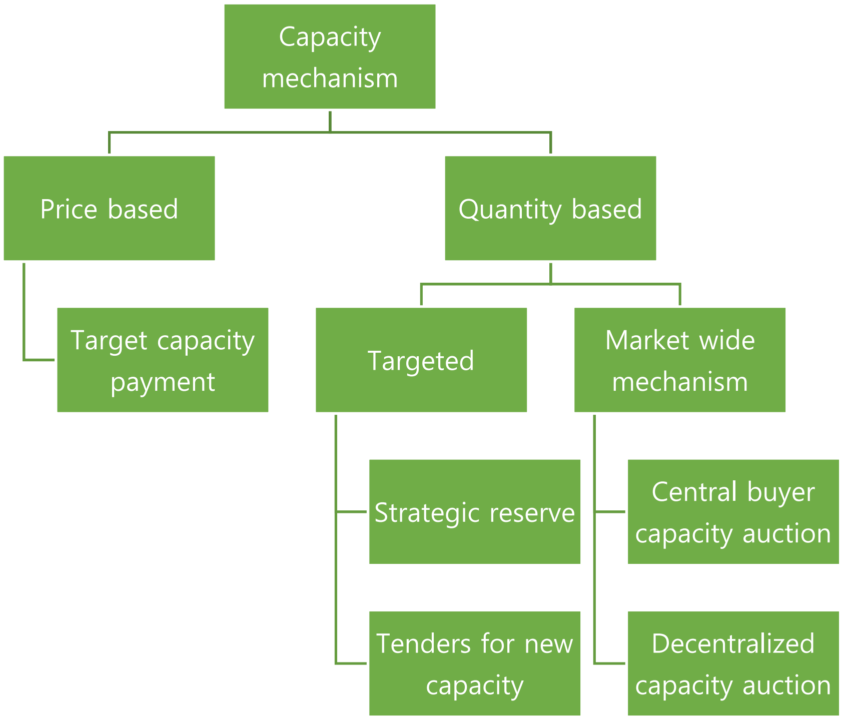
The main objective of a capacity mechanism is to ensure adequate resources are available to provide reliable supply. An explicit mechanism reduces the reliance on spot energy prices to signal the need for investment.

There are various ways to procure capacity. Some of the most common methods are shown in Figure 3. At high level, the two key divisions are whether a regime is:

- price-based or quantity based; or
- targeted to specific facilities or technologies, or applicable to all facilities in the market.

Different regimes may include aspects of more than one type of mechanism.

Figure 3: Capacity procurement options



2.2.1 Targeted Capacity Payment

In a targeted capacity payment regime, only specific types of new entrant technology are eligible for capacity payments. The payment is linked to a contracted strike price, set by a central body to reflect the cost of entry of that technology. There may or may not be restrictions on the quantity of generation that can receive the guaranteed price. This mechanism has been used in Spain and Portugal.

2.2.2 Strategic Reserve

A strategic reserve is a collection of facilities which do not usually participate in the spot energy market. They are held back from dispatch until all other facilities have been used. The strategic reserve facilities are then dispatched and are settled at a very high price. This approach has also been used in various European countries such as Sweden, Germany, Belgium, and Finland. The NEM Reliability and Emergency Reserve Trader regime functions in this way. New Zealand implemented a form of this approach between 2006 and 2010, using a spot price trigger for deploying the reserve.

2.2.3 Tenders for new capacity

Under a targeted tender-based approach, a central body determines capacity needs, requests tenders for building new capacity, and directly contracts with participants for new facility build.

This approach tends to be present in markets where utilities are in public ownership, or there is a single energy buyer. Bulgaria and Croatia use such tenders for procuring capacity.

2.2.4 Central buyer capacity auction

The most common capacity procurement mechanism in deregulated markets is a centralised auction. The capacity requirement is determined by a central body, and capacity is procured centrally through a competitive auction. The system operator assigns capacity based on the capability of the resource, and the auction determines the quantity of capacity each resource is allocated, and the price paid for the capacity. Centralised auctions are used by Italy, UK, Ireland, Poland, ISO New England, Mid-continent ISO, New York ISO, and PJM.

2.2.5 De-centralized capacity obligations

With decentralised obligations, no central party acts as a counterparty to capacity providers. Load serving entities are obliged to forecast their expected load, and to procure the necessary capacity to cover it, either via bilateral contracting or potentially through exchange facilitated trading. Two important markets using this kind of capacity procurement are France and California ISO (CAISO).

2.3 QUANTITY-BASED MARKET-WIDE CAPACITY MECHANISMS

The WEM RCM is a quantity-based market-wide mechanism and will remain so. For that reason, this international scan focuses on markets with those types of mechanism: PJM, ISO New England, France, Colombia, United Kingdom, and Ireland.

While an energy market compensates facilities for providing energy in or near real-time, a capacity mechanism pays facilities to ensure they are available to provide electricity in the future. Capacity payments provide another revenue stream for scheduled generators to cover at least some of the fixed cost of building and maintaining the resource, leaving the energy market primarily as a vehicle to recover variable operational costs. A well-functioning capacity mechanism must be able to:

- procure the right mix of resources to ensure system reliability at the lowest cost, in a sustainable manner;
- avoid price volatility;
- provide a revenue stream for recovering fixed costs; and
- most importantly, provide the right price signals about the level of investment required.

Each jurisdiction will have an explicit or implicit 'capacity price'. A higher capacity price reflects shortage of capacity and encourages investment while a lower (or zero) capacity price reflects excess capacity available.

2.3.1 Reliability metrics and capacity requirements

Some party must forecast grid demand and determine the quantity of capacity required to meet a specified reliability criterion. Projected demand and the reliability criterion must consider a range of issues, including population and economic growth, prevailing weather, climate change, demand response activity and changes in consumption patterns. Most jurisdictions review their capacity requirement every year for a future period based on estimated demand forecasts.

The most common reliability metric is the Loss of Load Expectation (LOLE). A LOLE or Loss of Load Probability (LOLP) analysis is typically performed on a system to determine the amount of capacity that needs to be installed to meet the desired reliability target, commonly expressed as an expected value, or LOLE. Another common metric is Loss of Load Hours (LOLH). These calculations involve combining load profiles and scheduled facility outages with the probability of forced facility outages to determine the expected number of occasions (LOLE/LOLP) or hours (LOLH) in the year when a shortage might occur. LOLP/LOLE/LOLH do not measure the total shortfall in capacity that occurs at the time when there are disconnections, nor do they measure the total quantity of unmet demand. LOLE does not mean power blackouts are expected. It is a metric for Transmission System Operators to use instruments such as temporary voltage reductions or the selective disconnection of large industrial users to prevent blackouts.

Once the overall capacity requirement is calculated, it will be translated into obligations for retailers and wholesale market consumers to hold capacity credits. Obligations reflect net usage during periods of system stress.

2.3.2 Facility capacity contributions

Some party must determine the contribution of each facility to meeting the future capacity requirement.

Usually, a central body assesses the ability of each resource provider to contribute to meeting capacity requirements, accounting for various aspects of operation, including:

- Historic reliability and outage rates;

- Derating[6] factors for intermittent generators;
- Fuel availability;
- Location; and
- Plans for plant retirement.

Each Facility will have capacity credits assigned. The initial holders of these credits are the generators and the demand response providers, who can then either sell them directly to retailers and wholesale market consumers or sell it to a central body who in turn allocates costs to load serving entities. Generators and demand response providers are obliged to provide capacity (for which they will be paid) during the commitment period which can be from a year to multiple years based on the market rules. Facilities failing to provide capacity during stated periods face penalties.

[6] Derating refers to the decrease in the available capacity of the generating unit to consider factors which could prevent it from running at full capacity. For example, a wind generator is derated to account for wind conditions affecting production and solar generation is derated to account for solar irradiance at different times of day.

3 International review of capacity mechanisms

With ambitious climate targets, increased intermittent sources like renewables and batteries and participation of demand side resources, several jurisdictions are considering changes to the way their capacity mechanisms operate. The WEM can learn from the issues faced in other markets and responses to those challenges.

While the overall purpose of every capacity mechanism is to ensure secure, reliable, and affordable electricity for consumers into the future, each market has unique characteristics which differentiate them. For this review, we have considered markets with a quantity-based market-wide capacity mechanism:

- Pennsylvania, New Jersey, and Maryland Regional Transmission Organization (PJM RTO);
- New England Independent System Operator (ISO-NE);

  PJM and ISO-NE are two of the most sophisticated wholesale energy markets in the United States, using a centralized auction for procurement of capacity with interties with neighbouring markets.

- France;

  The French electricity market has a decentralized capacity procurement method with similarities to the WEM RCM, although the generation fleet is very different.

- Colombia;

  Colombia brings in a South American perspective and is one of the few markets which seeks to address the reliability issue over a much longer period (mainly because of hydro risk associated with the generation mix).

- UK;

  The UK was explicitly referenced in the review ToR, having introduced its capacity mechanism in 2013.

- Ireland;

  Ireland is a small market (though larger than the WEM), with high renewable penetration.

Like the WEM, PJM, ISO-NE, UK, and Ireland have a high share of gas resource in their electricity generation mix.

This chapter describes each market, presenting:

- A table summarising key market design elements;
- An overview of the market structure, including design elements and characteristics of the generation fleet;
- A description of the capacity mechanism;
- A discussion of issues faced, and how they are being dealt with.

3.1 PJM

MARKET INFORMATION	
Energy Market	
Gross vs Net pool	Gross pool
Trading interval	5 minutes
Locational pricing	Yes
Day ahead market	Yes
Real time market	Yes
Interties	Yes
Capacity mechanism	
Procurement structure	Reliability Pricing Model
Additional features	Bilateral trading
Auction type	Mandatory centralized uniform price auction
Resource adequacy requirement	System wide and local requirements set by 0.1 LOLE study (i.e.) 1 event in 10 years
Timeline	3 years in advance. Incremental auctions are held up to the delivery year.
Price information	Sloped demand curve is used based on the system capacity requirement, the net-CONE, and demand reservation prices.
Intermittent in capacity mechanism	Can receive RE support from state as well as partake in capacity market

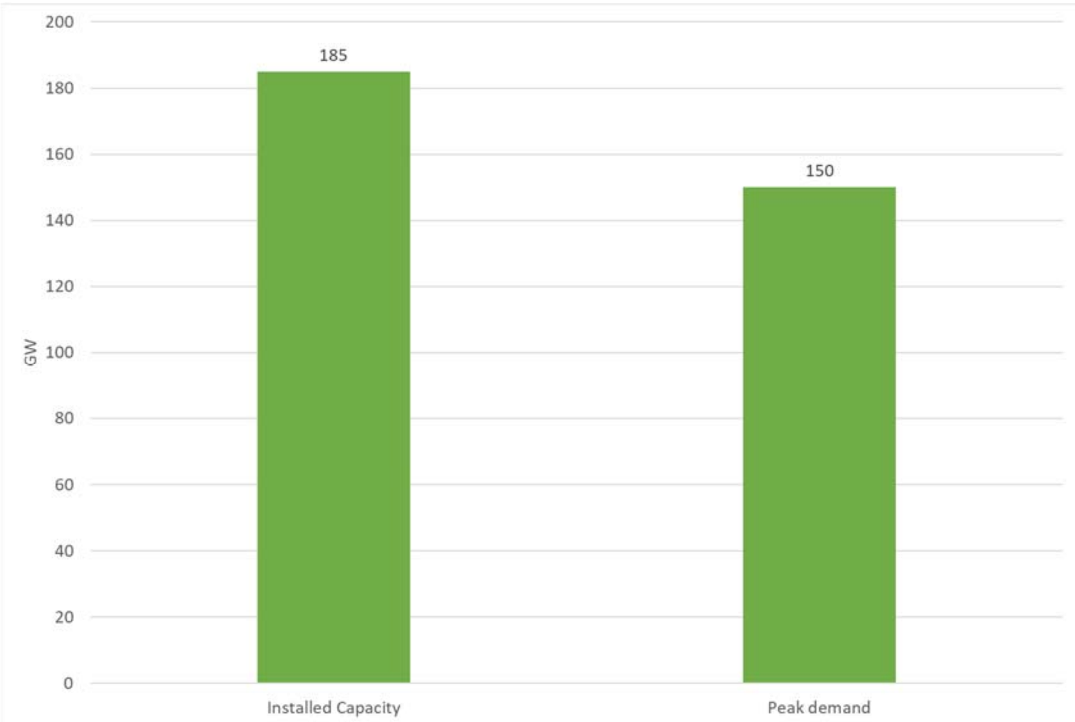
3.1.1 Market structure

PJM is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of 13 states and the District of Colombia. PJM's wholesale market was established on 1 January 1999. It is connected to neighbouring regions through high voltage DC lines. In 2007, the market was redesigned to reflect incremental improvements and retail deregulation. The wholesale markets run on a gross pool arrangement where electricity is traded every 5 minutes. PJM administers and runs the following markets to ensure the reliable and affordable delivery of electricity:

- Day-ahead energy market;
- Real-time energy market;
- Capacity market;
- Financial transmission rights market;
- Day-ahead scheduling reserve market;
- Synchronized reserve market[7]; and
- Regulation market.

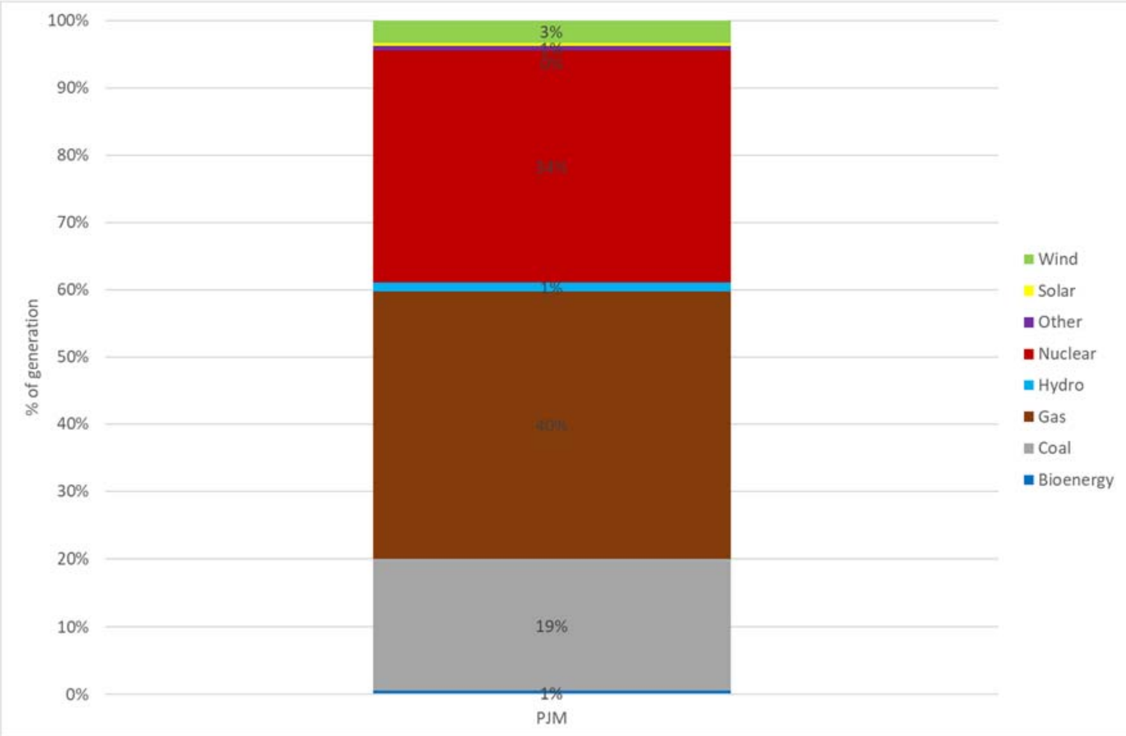
In 2019, the installed capacity was 22% higher than the peak demand. The generation mix was dominated by natural gas in 2020, which contributed to about 40% of the total generation, followed by nuclear and coal. Wind contributed to about 3% of the total generation while solar generation was less than 0.5% of the total generation.

Figure 4: PJM - 2019 Installed Capacity vs Peak demand



[7] Energy and reserve markets in PJM are co-optimized during dispatch.

Figure 5: PJM - 2020 Generation mix[8][9]



3.1.2 Capacity mechanism arrangement

Market structure

PJM's capacity mechanism is called the Reliability Pricing Model (RPM). This is used to acquire resources to meet the North American Electric Reliability Council (NERC) Reliability Standards. RPM divides the PJM region into Locational Deliverability Areas (LDAs) that reflect the supply and demand conditions in different locations, reflecting zones of expected transmission congestion. There are 25 LDAs in PJM, which consists of regions, zones, and subzones. The goal of the RPM is to align capacity pricing with system reliability requirements and to provide transparent information to all market participants, far enough in advance to allow the participants to take actionable response to the information. In the RPM, the fundamental elements to achieve this are:

- Locational Capacity Pricing to recognize and quantify the locational value of capacity;
- Variable Resource Requirement mechanism to adjust price based on the level of resources procured and to generate the demand curve used in the Base Residual Auction (BRA);

[8] The total may not add up to 100% because of rounding.

[9] 'Other' includes methanol, oil, distillate, steam, wood, fuel-cell, jet fuel.

- Forward Commitment of supply by generation, demand resources, energy efficiency resources, and qualified transmission upgrades cleared in a multi-auction structure; and
- A Reliability Backstop mechanism to ensure that sufficient generation, transmission, and demand response solutions will be available to preserve system reliability.

The RPM is a multi-auction structure designed to procure services from resource providers and Load Serving Entities (LSE) to satisfy the region's *unforced* capacity obligation through the following market mechanisms:

- The Base Residual Auction (BRA): The BRA is a mandatory centralized forward uniform price auction which is held three years prior to the start of the Delivery Year. It allows for the procurement of resource commitments to satisfy the region's unforced capacity obligation based on peak load forecasts and the Forecast Pool Requirement (FPR)[10]. This allocates the cost of those commitments among the LSEs through a Locational Reliability Charge.
- Incremental Auctions: At least three Incremental Auctions (First, Second and Third) are conducted after the Base Residual Auction to procure additional resource commitments needed to satisfy changes in market dynamics such as replacement resource procurement, and increases and decreases in resource commitments that are known prior to the beginning of the Delivery Year. Conditional Incremental Auctions may be conducted if a Backbone transmission line is delayed and results in the need for PJM to procure additional capacity in a LDAs to address the corresponding reliability issues.
- The Bilateral Market: The bilateral market provides resource providers an opportunity to cover any auction commitment shortages. The bilateral market also provides LSEs the opportunity to hedge against the Locational Reliability Charge. The bilateral market is facilitated through the Capacity Exchange system.

LSEs and resource providers can either participate in the BRA and three incremental auctions following that or can opt out of the BRA by participating in the Fixed Resource Requirement (FRR) alternative. The FRR Alternative provides an LSE with the option to submit a FRR Capacity Plan and meet a fixed capacity resource requirement as an alternative to the requirement to participate in the RPM, which includes a variable capacity resource requirement.

[10] $FPR = (1 + InstalledReserveMargin) * (1 - PoolWideAverageEFORd)$

Reliability criterion

PJM performs resource adequacy calculations every year for an 11-year future period. The reliability criterion in PJM is 0.1 (i.e. 1 event in 10 years). The analysis considers load forecast uncertainty, forced outages, planned and unplanned maintenance.

The target reserve margin is established by running a probabilistic model that predicts conditions like resource outages and demand from loads. This is given by the formula

$$LOLE = \sum_{i=1}^{260}\sum_{j=1}^{21} P(D_j) \times P(G < D_j)$$

Where i is the number of weekdays for the given capacity year (number varies based on the year), j is the position in the 21-point Gaussian distribution representing weekday i's Most Probable Peak, $P(D_j)$ is the probability of j^{th} load value occurring and $P(G)$ is the probability of available generation.

The process of determining the reserve margin for meeting the reliability criterion assumes that the network is unconstrained. However, since there will be limits on transmission lines, Load Deliverability tests are conducted by dividing the whole region into three LDAs.

Demand curve

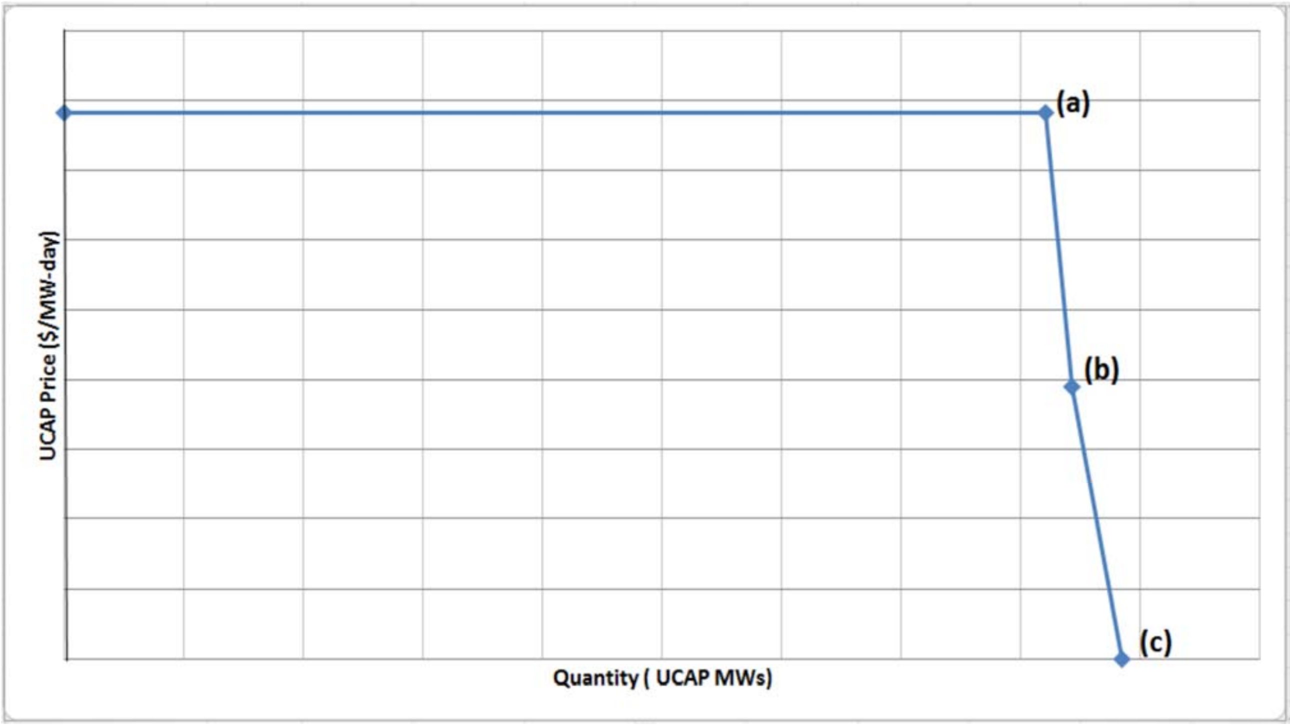
The Variable Resource Requirement (VRR) is the demand curve that represents the trade-off between reliability and cost. The VRR curve is defined in such a way that the 1-in-10-year LOLE reliability standard is achieved and maintained over time based on the CONE.

The value for CONE is determined as entry of a Combustion Turbine (CT) generating station, configured with a single General Electric Frame 7HA turbine[11]. The upper limit of the VRR curve is determined by the net CONE which is the gross CONE for the PJM Region minus the Net Energy and Ancillary Services (E&AS) profit offset for the PJM Region.

After satisfying the reliability requirements, the value the customers place on additional capacity for improved reliability drops rapidly, leading to a steep downward slope, as shown in Figure 6.

[11] PJM CONE

Figure 6: Variable Resource Requirement Curve (PJM Manual 18: PJM Capacity Market)



Market clearing

The capacity market clears on an Unforced Capacity basis (UCAP) as opposed to an Installed Capacity (ICAP) basis.

- The installed capacity value of a generation resource is based on the summer net dependable rating of a unit, also referred to as "Iron in the Ground".
- The unforced capacity value of a generation resource is installed capacity rated at summer conditions that is not on average experiencing a forced outage or forced de-rating.

The market clears both system-wide and for each capacity zone to meet the requirement as reflected through the VRR curves. This process produces different locational prices when transmission constraints between the zones are binding.

The supply offers are bid into the auction by the resource providers or demand side resources forming the supply curve which intersects the demand curve to determine the market clearing price for the BRA. Capacity suppliers are paid the clearing price associated with the location at which their resources clear.

If existing resources cannot offer bids lower than the cost of entering the market, then it signifies that it is cheaper to build new generation than to use existing resources. In 2021/2022 BRA, CONE was $135,309/MW/year and the net CONE was $110,458/MW/year while for the same period, the PJM capacity market attracted close to 170,000 MW at a capacity-weighted average 51.1% below net CONE, demonstrating a healthy competitive environment[12].

Determining Capacity Contributions

The purpose of the market is to meet the forecast load and to match the reliability criterion. To achieve this, resources must participate in the market and prove their reliability based on various tests determined by PJM.

The reliability value of a resource depends on two variables:

- The installed capacity of the resource; and
- A probability that a resource will not be available due to forced outages or forced deratings.

The combination of the two determines the UCAP of the resource. For a resource to qualify as a Capacity Performance Resource, it must be capable of providing sustained and reliable supply of energy throughout the entire delivery year, to ensure it is available during emergency conditions.

The resource adequacy of a conventional generation source is determined based on its nameplate capacity around the year. It is the obligation of the generating resource to ensure adequate supply of fuel if it is qualified as a capacity resource, failing which it will face penalties.

Wind and solar resources are not required to offer into the capacity market and may need to aggregate with other seasonal resources to provide the year-round capability required of all Capacity Performance resources. Given the weather dependant nature of intermittent generators (solar, wind) as well as capacity storage resources, the unforced capacity for these facilities is based on the average hourly output during expected performance hours in summer and winter. The expected performance hours in the summer are hours ending 15:00 through 20:00 EPT in June, July, and August. The expected performance hours in the winter are hours ending 6:00 through 9:00 EPT and 18:00 through 21:00 EPT in January and February.

An Energy Efficiency (EE)[13] resource must achieve a continuous, permanent reduction in energy consumption at the end customer's retail site, which will be calculated during EE performance hours between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from

[12] 2021-2022 RPM Base Residual Auction Planning Parameters.

[13] EE Resource is a project that involves the installation of more efficient devices/equipment, or the implementation of more efficient processes/systems, exceeding then-current building codes, appliance standards, or other relevant standards

June 1 through August 31, inclusive, of such Delivery Year, that is not a weekend or federal holiday. A qualified transmission upgrade can be bid into the BRA to increase the transmission capability between constrained LDAs.

3.1.3 Issues with the capacity mechanism

Historically, the capacity market has been able to acquire adequate resource to remain within the 1-in-10 LOLE reliability criterion. With new technologies such as renewables and storage resources entering the market, PJM has investigated or is investigating potential changes to various aspects of the capacity market to better suit the changing circumstances.

Suitability of the reliability criterion

The current reliability standard is 1-in-10 LOLE or 0.1 LOLE. This means that the capacity mechanism procures resources to a level that allows for, on average, one loss of load event every 10 years.

This 0.1 LOLE standard was set when the only power producers were conventional generators, which could provide power 24 hours a day, except when on planned or forced outage.

From 2014 to 2018, the forecast based on the 1 in 10 peak reliability standard has been historically 2.5% greater than the actual demand. This has been sufficient to allow PJM to acquire resources to ensure reliability of supply. With more intermittent resources on the system, this reliability standard may not appropriately reflect all system stress events, as it does not consider the magnitude or duration of the LOLE event. For example, a load shed event of one MW in one hour is treated the same as 1000 MW load shed across 10 hours.

PJM considers it is important now to consider the duration and the amount of load shed in determining the reliability criterion. We discuss this issue further in section 4.2.

Reliability contribution of renewable resources

Under current arrangements, the unforced capacity of intermittent resources is evaluated for defined periods in summer and winter – the expected performance hours.

Increasingly, performance in hours outside the expected performance hours is becoming more important.

Seeking to address this issue, PJM proposed to FERC a new method for evaluating the contribution of renewable resources based on their Effective Load Carrying Capability (ELCC). A resource’s ELCC value measures the equivalent amount of additional load the system could serve (“carry”) with the resource (versus without it), while meeting the same LOLE target. ELCC would involve a more robust probabilistic analysis which considers the contribution of the resource across time, to account for both peak and net-peak demand hours[14], correlation with other intermittent resources, and the availability and operation of storage resources.

Minimum Offer Price Rule

PJM's current Minimum Offer Price Rule (MOPR) was intended to ensure that vertically integrated entities cannot exercise buyer-side market power by offering capacity they own at artificially low prices that supress the total capacity price. It functions by setting a minimum price for new entrant capacity offers. This rule also captures facilities which receive or are eligible to receive state subsidies. Currently, all new resources as well as some existing resources receiving subsidies are subject to MOPR.

The offer price floor for new resources is equal to the (administratively determined) unit specific net CONE, which is the revenue that a plant needs to earn during its first year in the capacity market to cover investment and fixed operating costs, minus the expected profits earned from the energy and ancillary services markets. For existing resources, MOPR is set equal to the net Avoidable Cost Rate (ACR), which is the same for every unit of a particular resource type, based on the annual fixed costs minus expected profits from energy and ancillary services markets. The MOPR for new renewable resources is higher than the capacity clearing prices (ranging from $140 to $205 per MW per day in the 2021/2022 BRA[15]).

Critics of MOPR argue that it protects incumbent fossil-fired power plants from competition from new plants being built as a part of modernizing the grid. This is because renewables and state supported renewable plants are forced to offer their capacity at artificially higher prices to account for other revenue streams while plants close to end-of-life and fossil generators can offer their capacity at low prices, clear in the capacity market, and receive an extra revenue stream sufficient to postpone retirement. This also affects the state-supported nuclear power plants which can provide large quantities of zero-emission electricity. While most existing renewables are not bound by MOPR, new renewables are heavily affected. New renewables can still enter the energy and ancillary services markets without participating in the capacity market, but since the rule increases capacity prices, end users pay a higher charge for the same amount of capacity that they would have otherwise paid if not for the MOPR rule.

PJM is progressing a 'focused' MOPR rule to allow resources like wind and nuclear power plants receiving state subsidies to bid into the capacity market without being subject to a minimum offer price.

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[14] Net peak demand is the total electricity demand minus utility-scale solar generation at a given time and net-peak-demand hours (the "net peak" for short) typically occurs later in the evening than the actual demand peak.
[15] MOPR for Clean Energy in PJM

State participation in capacity procurement

According to the Federal Power Act, each individual US state has control over:

- Generation in its territory;
- Utilities serving customers; and
- Transactions between generators and utilities.

Because all load serving entities in PJM are required to participate in the capacity mechanism, PJM has complete control over the procurement of capacity for all 13 states within its purview. In effect, PJM's arrangements have precluded the potential for individual states to shape the generation fleet. The FRR does provide an alternative for LSEs to avoid direct participation in the capacity auction, but it does not allow them to do so in a way that states can use to further their own energy policy.

This issue will be addressed by making the PJM-administered capacity mechanism voluntary. PJM would still be responsible for guaranteeing resource adequacy, but states could procure capacity based on their own renewable energy and climate ambitions. Load serving entities will be able to procure capacity outside the PJM auction through state approved mechanisms and source any remainder through the PJM auctions. State regulators would have the authority to review adequacy of capacity purchases outside or within the PJM-administered mechanism.

3.2 ISO-NE

MARKET INFORMATION	
Energy Market	
Gross vs Net pool	Gross pool
Trading interval	5 minutes
Locational pricing	Yes
Day ahead market	Yes
Real time market	Yes
Interties	Yes
Capacity mechanism	
Procurement structure	Forward Capacity Auctions
Additional features	Bilateral trading
Auction type	Mandatory centralized descending clock auction
Resource adequacy requirement	System wide and local requirements set by 0.1 LOLE study
Timeline	3 years in advance. Incremental auctions are held annually and monthly
Price information	Sloped demand curve is used based on LOLE and net-CONE
Intermittent in capacity mechanism	Can receive RE support from state as well as partake in capacity market

3.2.1 Market structure

ISO-NE is an RTO that serves six states in the New England region. It is responsible for operating the 31,500 MW electric power system, ensuring day to day operation of the wholesale electricity market, and planning the region's electric power system. ISO-NE was created in 1997 to replace the New England Power pool. The wholesale spot market for electricity runs a gross pool market with electricity being traded every 5 minutes. ISO-NE operates the following markets mechanisms:

- Day ahead market;
- Real time market;

- Financial Transmission Rights market;
- Forward Capacity market;
- Forward Reserve market; and
- Regulation market.

In 2019, the installed capacity was 32% higher than the peak demand during the summer peak in July. The generation mix is dominated by natural gas followed by nuclear and hydro. Other renewable sources[16] contributed about 12.5% of the total generation in 2020, and this figure is increasing.

[16] The various types of hydroelectric generation (i.e., storage hydro, run-of-river, pumped storage) are not consistently defined as renewable in the six New England states.

Figure 7: ISO-NE - 2019 Installed Capacity vs Peak demand

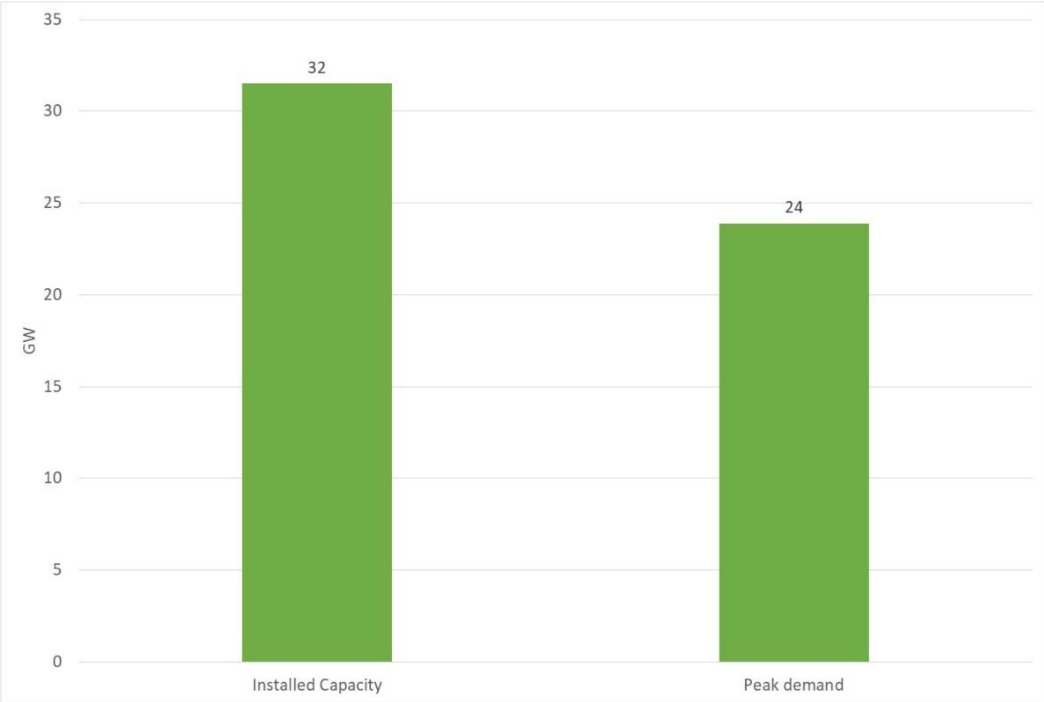
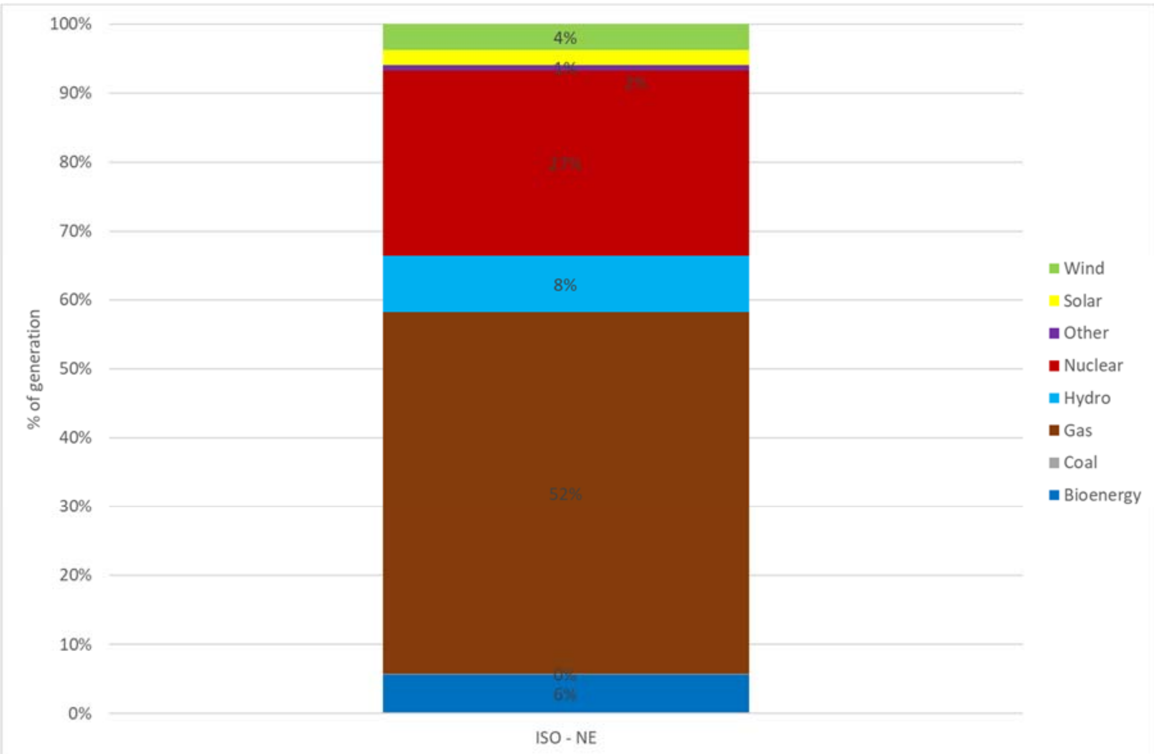


Figure 8: ISO-NE - 2020 generation mix



3.2.2 Capacity mechanism arrangement

In 1998, ISO-NE adapted an Installed capacity market to ensure availability of generation in times of high demand. The Forward Capacity Market (FCM) was established in 2008 and the first auction was held for the year 2010. As in PJM, capacity is procured to meet both the system wide requirement for the New England control area and the requirement in each of the four capacity zones.

FCM consists of a three year ahead mandatory capacity auction with a bilateral arrangement for trading capacity outside the auction among resource providers and buyers. The delivery period is called Capacity Commitment Period. The Forward Capacity Auction (FCA) is organized in a descending clock format basis where the market is cleared when supply offered by the resource providers (generating resources and demand participants) meets the demand which is based on the resource adequacy requirement. The resource adequacy requirement is based on a LOLE of 0.1 events per year (i.e. 1 event in 10 years). Following the three years ahead auction, there are monthly and annual auctions for parties to procure/provide resources based on market conditions closer to the delivery year.

The demand curve in the FCA is based on the CONE, net CONE, and LOLE. The CONE for the FCA for the commitment period beginning in 2025 is $12.400/kW-month ($148,800/MW/year) while the net CONE is from the same period is $7.468/kW-month ($90,000/MW/year)[17]. CONE and net CONE will be calculated every three years. Initially, the demand curve after a specified reserve margin was vertical. This meant that the implied value of capacity changed from high to zero with the addition of a single MW, increasing the risk for new investment and loads around this point in the demand curve. A sloped demand curve was then introduced to reflect the decreasing value of capacity greater than the reserve capacity margin: i.e. a high-capacity price signals that the region needs new power resource and addition of another resource would substantially improve reliability while a lower capacity price reflects excess supply, meaning that additional capacity would not improve system reliability as much.

Supply is offered by the resource providers in up to five price-quantity pairs in ascending price order, which cannot exceed the Capacity Supply Obligation (CSO) obtained in the primary auction. In the first round the market opens between two high prices and bidders are requested to bid within this price range. If at the end of round one, the offered quantity at the lower price bound is more than the demanded value, then the next round of auction begins with a price range between the lower price bound of round one and a new lower bound for round two. The auction ends when the offered quantity meets the demanded value, and at this point the clearing price and the corresponding quantity are determined. For each resource provider their Capacity Supply Obligation is based on the amount of capacity cleared in the auction.

[17] BRA planning period parameters

Determining Capacity Contributions

To participate in the FCM, resources must show capability to provide the necessary capacity during periods of peak demand. ISO-NE provides a platform for resources to provide commitment during either summer or winter peak demand periods.

The summer or winter Qualified Capacity of an existing generating capacity resource (excluding intermittent resources) for the FCA is the median of the existing generating capacity resource's summer or winter seasonal claimed capability rating for the previous five years.

For an intermittent resource, the ISO determines the median of the resource's net output in the summer intermittent reliability hours for the previous five years. The summer intermittent reliability hours are chosen to find the resource's contribution to capacity during peak demand periods (the hours ending 14:00 through to 18:00 each day between June and September and any other summer periods where there was a scarcity condition). Similarly, for winter reliability, the median of the resource's net output during the previous five winter intermittent reliability periods is chosen (the hours ending 18:00 through to 19:00 each day between October and May of the next year and any other winter periods where there was a scarcity condition). Reserve Constraint Penalty Factors are rates, in $/MWh, that act as a cap on the price that the ISO may pay to procure additional reserves; reaching this cap signals that the system is in a reserve deficiency/scarcity condition. RCPFs are intended to send price signals to the marketplace when resources are scarce. Higher RCPFs provide stronger signals for resources to increase supply and for customers to reduce demand.

Demand capacity resources consist of one or more demand resources located in a single dispatch zone. Demand resources may take the form of load management, distributed generation, energy efficiency, or a combination of these resources. The reliability of these resources is also measured during historical peak demand and system stress periods

3.2.3 Issues with the capacity mechanism

An efficient capacity market compensates resources according to the marginal reliability value[18] it provides to the market. To achieve efficiency, ISO-NE must accurately assess reliability and system adequacy needs and how reliability is affected by addition or loss of different resources. Not doing so will distort price signals and could lead to inadequate procurement of resources to meet the reliability criterion. Currently, ISO-NE compensates capacity in a way that is inconsistent with the marginal impact on reliability. Current methods do not account for conventional generators with low flexibility, large generators whose outage leads to large and more impactful

[18] The improvement in system reliability that a small increment of the resource provides.

fall in supply, gas units that lack backup fuel, intermittent resources, and energy storage. To this end, the following issues were identified with the FCM:

Method of assigning capacity credits

Each capacity credit represents one MW of capacity that a resource may offer into the capacity mechanism and be compensated for if clearing the capacity auction. The resource is given a Capacity Supply Obligation (CSO) based on its Qualified Capacity rating, calculated as the maximum rated output for conventional generators and the seasonal median output during set hours of the day (as mentioned in the previous section) for intermittent resources.

In the calculation of Qualified Capacity for conventional generators, the following factors are not considered:

- Lower flexibility of some of the resources due to longer start time and limited operational flexibility. This is not accounted for in the Qualified Capacity for the unit;
- The size of the resource is not account for in assigning Qualified Capacity. The issue is that larger units provide less reliability when compared to several smaller units of the same capacity as an outage of a single large unit leads to contingency issues while simultaneous outages of multiple small units are much less likely.

For intermittent resources, the Qualified Capacity is calculated based on the seasonal median output during certain times of the day. The hours chosen are based on the historical peak periods during which conventional generators supplied more than 90% of total energy generated. With more renewables entering the market, the current Qualified Capacity fails to capture the contribution of intermittent when the risk of load shedding is the highest. This is because output of several intermittent resources of the same type and the geographic area is correlated. The hours when output from all wind or solar capacity is low are more likely to be when additional capacity is needed, and the current median output calculation does not reflect this dynamic. A higher share of intermittent resources shifts the net (of intermittent) peak demand towards a time when the output of intermittent is low – i.e. not the historical peak demand period during summer and winter evenings. These are the hours when the net load that must be served by other resources is high even though the gross demand may not be particularly high.

Under the current rules for storage capacity accreditation, storage that can discharge for two hours can offer Qualified Capacity up to 100% of its installed capacity. But the marginal reliability of storage resources depends on the number of hours it can run, penetration of renewable resources and other storage resources. The current system for determining the Qualified

Capacity of storage resources fails to capture these factors which must be accounted for in determining their contribution to reliability.

Inefficient assignment of capacity credits can lead to price signals being distorted for investment in the right technologies and lead to over investment in resources which do not provide the necessary reliability.

Reliance on gas

With gas-fired resources providing over 50% of total electricity generated, ISO-NE is now highly reliant on the natural gas supply chain for fuel to supply the gas plants providing capacity. The system has run near capacity during periods of peak demand in winter due to the time consuming need to ship natural gas over long distances. With natural gas, wind, and solar resources pushing oil peakers and historically baseload coal resources out of the market (mainly due to emission targets), gas-fired power plants are increasingly needed to provide capacity during periods of peak demand.

One supply issue with the provision of natural gas is that most of the gas generators do not have firm gas supply contracts and tend to buy gas on the spot market. The gas supply chain is highly influenced by global economics and logistics. This can in part be addressed by energy storage, wind and solar power but given the weather dependant nature of these resources, a reliable source of gas is necessary for ensuring security of supply.

Some of these issues can be addressed by investing in a diverse resource mix, by rewarding resources which are uncorrelated with each other thereby reducing the dependence on a single fuel source.

3.3 France

MARKET INFORMATION	
Energy Market	
Gross vs Net pool	Net pool
Trading interval	30 minutes
Locational pricing	No
Day ahead market	Yes
Real time market	Yes
Interties	Yes
Capacity mechanism	
Procurement structure	Decentralized capacity procurement
Additional features	Optional participation with obligation
Auction type	Optional auction
Resource adequacy requirement	Local requirements based on LOLE which is 3 hours per year
Timeline	Market operates on a continuous basis until delivery. Trades can take place in OTC or organized exchanges
Price information	Certificates are traded with a price cap of €60 000/MW (2020)
Intermittent in capacity mechanism	Diminishes RE revenue when participating in the capacity mechanism

3.3.1 Market structure

France is usually a net exporter of electricity. The overall operation of the French electricity and gas market is regulated by Energy Regulation Commission (CRE). Réseau de Transport d'Electricité (RTE) is the transmission system operator, responsible for maintaining and operating the grid and balancing supply and demand in real time. RTE also is responsible for operating the capacity mechanism to ensure enough capacity to meet the peak demand which generally occurs during winter periods. RTE runs a competitive wholesale electricity market to ensure secure and reliable supply of power to end users while compensating the power producers in a fare and competitive way. The wholesale market includes:

- Capacity mechanism;
- Exchange traded financial markets;
- Day ahead market;
- Intraday market; and
- Balancing and system services with reserves.

In 2019, the peak demand was 88.5 GW in January while the installed capacity was 96.8 GW (including interconnections) which is 9% higher than the peak demand. Nuclear energy produces around 70% of the total electricity demand, followed by hydro and gas. Wind, biogas and solar contribute to around 10% of the total generation in 2020. RTE’s market rules are well equipped to allow participation of intermittent renewable generation and flexible capacity facilities (including batteries) through explicit renewable support funding and the through the capacity mechanism.

Figure 9: France – 2019 – Installed Capacity vs Peak Demand

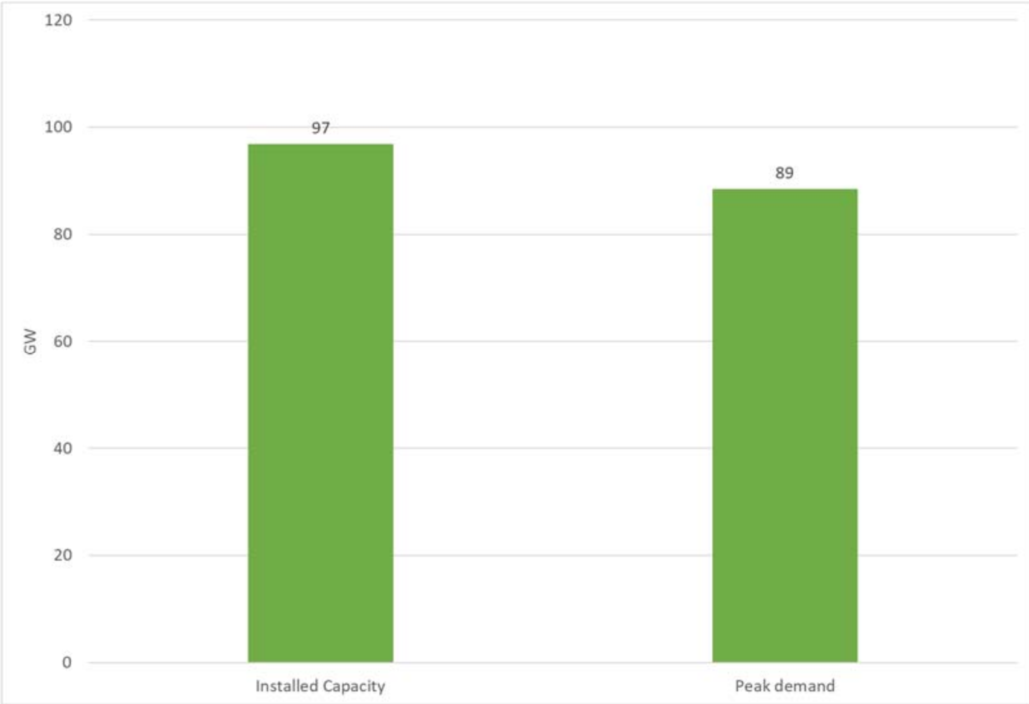
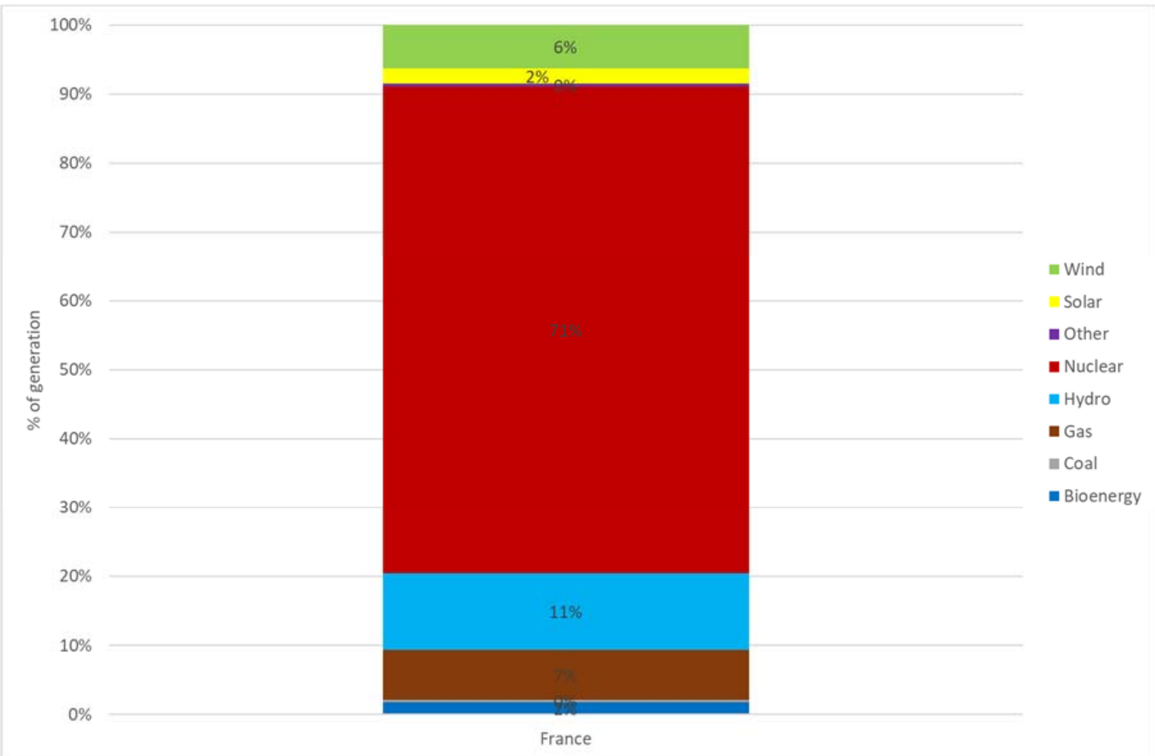


Figure 10: France - 2020 Generation mix



3.3.2 Capacity mechanism arrangement

France first implemented its capacity mechanism in 2016 for the 2017 delivery year. The market is a decentralized capacity mechanism with reliability obligations. Under a decentralized model, suppliers are responsible for system adequacy, matching their own supply and demand. The reliability criterion provides for a 3-hour LOLE. Capacity providers offer capacity when the demand is the highest, especially during peak winter periods. The capacity mechanism is open to generators and demand response providers in France and neighbouring countries.

In addition to the decentralised capacity scheme (which only provide capacity resources with a single year of revenue at a time), RTE also operates underwriting schemes to provide longer term support for specific types of generation and demand response. Through this underwriting scheme, new low emission facilities and energy storage can be offered up to 7-year contracts if they are shown to be more competitive than existing capacities. In the 2020 underwriting auction held by RTE for new capacity, 253 MW of energy storage and 124 MW of demand response capacity were awarded 7-year contracts. The auction had strict emission requirements of 200 g of CO_2 per kWh or less, which led to the disqualification of two of the four applicants seeking 7-year contracts. Separate contracts are provided for battery storage in France whereas in UK, it participated as demand side response[19].

RTE provides the following services in relation to the operation of the decentralised capacity mechanism:

- Preparing energy consumption forecasts in the short term to determine peak demand periods and assist participants to identify the capacity needed for that period;
- Issuing of capacity certificates, calculation, and notification of obligations for each capacity provider during periods of peak demand based on the commitments made by the party to offer/curtail capacity;
- Assessing the effectiveness of the capacity suppliers (including curtailment), calculation of capacity gaps based on ex-post data, keeping records of the certified capacities and of the capacity guarantees; and
- Proposing rules for the capacity mechanism.

First, the suppliers are obliged to obtain capacity certificates to meet their expected peak demand based on their end customer energy usage. Then the generation resources are then certified by RTE based on the generation capacity which they are willing to offer during periods of peak demand. Each certificate is equivalent to 0.1 MW. Generators are required to certify their capacity four years before the delivery year.

[19] Storage prevails in France's capacity auction

Demand-side response can be used by two different methods: either by reducing a supplier's capacity obligation by reducing consumption ('implicit demand-side response') or by certifying demand-side response capacity ('explicit demand-side response').

Market participants and resource owners can exchange certificates either bilaterally on the OTC market or enter auctions organised by EPEX SPOT (a commercial entity). In 2020, the price for capacity certificates was capped at 60,000 €/MW[20]. This price cap is the penalty set for the obligated parties for failing to acquire enough capacity certificates.

During the delivery year, RTE notifies participants a day ahead that the following day will be a peak demand day, also referred to as a Peak Performance (PP) days. There are two categories of PP days, each relating to different obligations on market participants:

- PP1 days (15 days) which are used to determine obligated party (retailers and end users) actual consumption for comparison to the level of capacity credits held. On these days, suppliers have incentive to limit their consumption in peak periods to the level of capacity credits they have procured. There are generally 11 PP1 days in January-February-March period, and 4 over the November-December period.
- PP2 days (25 days, of which 15 will also be PP1 days) during which capacity suppliers (generation and demand response) are required to perform, and on which their availability will be assessed.

The obligations for the two types of demand-side response capacity are different: implicit demand-side response must be activated during PP1 hours, whereas explicit demand-side response must be available during PP2 hours.

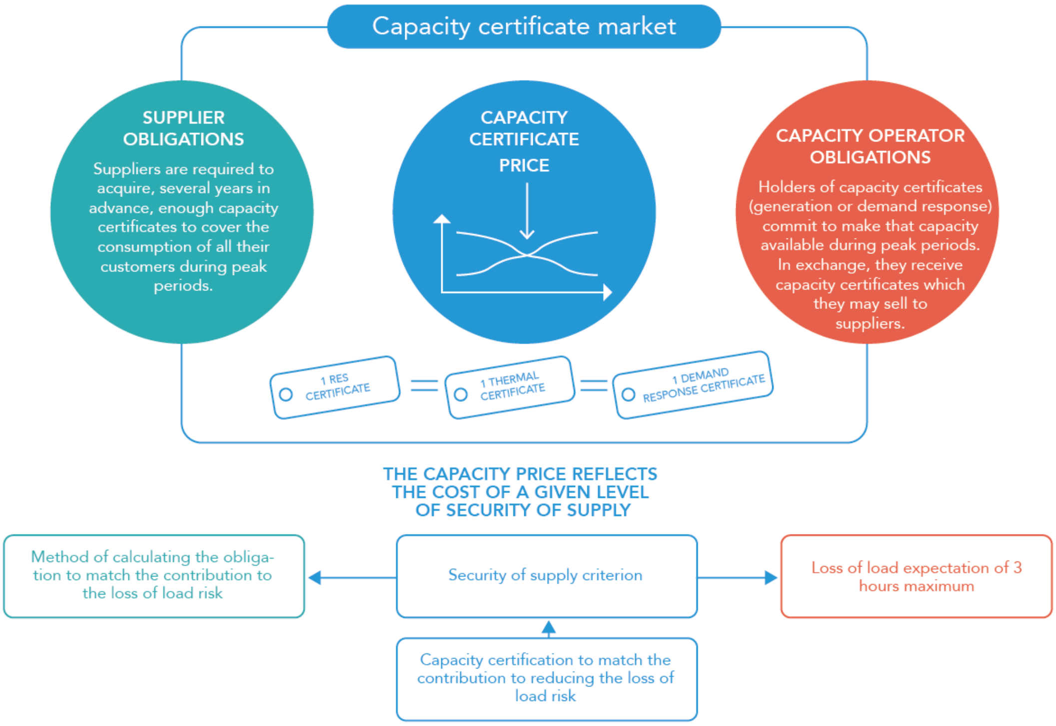
PP1 and PP2 days are differentiated based on a threshold of expected demand. On both types of day, the respective parties must fulfil their capacity obligations from 7:00 to 15:00 and from 18:00 to 20:00[21].

Three years after the delivery year, RTE informs suppliers of their final obligation level (based on actual usage in the PP1 days) and calculates actual availability for capacity providers. Differences and penalties are settled by RTE.

[20] Capacity Certificate price cap

[21] Capacity mechanism in France

Figure 11: Working of French Capacity Mechanism (RTE Electricity Report 2020)



Determining Capacity Contributions

The capacity mechanism does not explicitly distinguish between different capacity sources for providing capacity certificates and there are no locational distinctions. Each thermal facility is awarded certificates based on its nameplate capacity as indicated by the capacity owner and provides the offered capacity during periods of peak demand. For intermittent generators, RTE issues certificates, calculated based on the original data, together with corrections reflecting the risk of non-availability, for example in the case of wind, hydro, or solar generation.

Foreign capacity providers can participate in the capacity mechanism if they obtain 'French Mechanism Admission Tickets' auctioned at each border, based on interconnector capacity.

Initially intermittent generators were not allowed to participate in the capacity mechanism, on the basis that feed-in tariffs were already compensating for full project costs, but CER determined that there should be no exceptions or distinction between capacities in the capacity mechanism. Intermittent energy providers are now allowed to participate in the capacity mechanism, but any compensation from renewable subsidy mechanisms is reduced equivalent to the capacity revenue. Though the compensation is reduced; wind can be offered seven year contracts to facilitate new investments and to provide a steady stream of revenue in the long run.

Wind and solar resources can opt for two different certification processes:

- **The standard procedure:** The certified capacity assigned to each resource depends on its production during winter peak-demand hours - from 7 a.m. to 3 p.m. and from 6 to 9 p.m. of the peak performance days. Resources estimate in advance their expected production during these peak hours (self-certification) and this forecast is then verified ex-post according to the actual production to calculate possible unbalances to be settled. With this method, they are exposed to the risk of forced outage of their facility as well as to the risk of unavailability of the primary energy source.
- **The normative procedure:** The normative certified capacity is computed from the historical average production of each resource during peak hours. This is similar to ELCC where the installed capacity of the technology under study is incremented in a reference system and the resulting LOLE is computed; some capacity of a "perfect resource" is added to the same reference system until reaching the same value of LOLE. This is calculated by the system operator and hence are exempted from the risk related to the unavailability of the primary energy source

3.3.3 Issues with the capacity mechanism

Market concentration

As mentioned in section 3.3.1, nuclear power dominates the electricity mix, and France is a net exporter of electricity to neighbouring countries at times of peak demand. All nuclear generation facilities in France are owned by Électricité de France (EDF), meaning that one entity owns most of the generation portfolio.

This lack of diversification can lead to problems with resource adequacy when there are problems with nuclear generation. Recently, five of EDF's 56 reactors were simultaneously affected by the same technological issue. As a result:

- French nuclear output in 2022 will be the lowest in the last 30 years[22].
- France had to import power from UK during peak hours over the 2021-22 winter.
- The wholesale electricity price will be four times higher than previous years due to the loss of baseload generation.

This problem has been exacerbated by record high gas, coal and carbon permit prices and shortfall in other generation capabilities. During the fourth quarter of 2021, France became a

[22] French Nuclear Giant's Fall Risks Energy Security for All Europe - Bloomberg

major importer moving into winter as day-ahead prices rose on the continent and high French electrical heating demand in conjunction with low nuclear production pushed up prices relative to neighbouring countries over much of November and December, incentivising more flows into France.

In response to the high prices, the French government has intervened in the market to cap retail energy bill increases to 4% and require that EDF must supply electricity at artificially lower prices. While this shields consumers from the high prices, it comes at the expense of losses for EDF, and reduced confidence in the stability of electricity trading arrangements.

This issue highlights the importance of diversifying generation sources. The political implications of encountering high electricity prices can be mitigated by investing in different technologies and diversifying resources.

3.4 COLOMBIA

MARKET INFORMATION	
Energy Market	
Gross vs Net pool	Gross pool
Trading interval	1 hour
Locational pricing	No
Day ahead market	Yes
Real time market	Yes
Interties	Yes
Capacity mechanism	
Procurement structure	Firm energy obligation auction
Additional features	Call option and bilateral trading through a reliability mechanism
Auction type	Centralized descending clock auction
Resource adequacy requirement	Local requirements set by CONE and LOLE
Timeline	3 years in advance. but this will increase by six months in each successive auction, until it reaches 4 years
Price information	Sloped demand curve with firm energy price having a ceiling of two times CONE and a floor of one-half times CONE.
Intermittent in capacity mechanism	Tenders occur in parallel but do not overlap

3.4.1 Market structure

In 1994, the Colombian government created the Colombian Wholesale Energy Market (MEM in Spanish) on the National Interconnected System (SIN). The market currently operates a single-node, day-ahead, bid based mandatory gross pool without locational constraints. Generators, network owners, distributors, energy consumers and unregulated users trade electricity at prices reflecting the marginal cost of supply. MEM is overseen by the Superintendent of Public and

Domiciliary (household) Services (SSPD). Compañía de Expertos en Mercados SA (XM) is the system and wholesale energy market operator. MEM includes three mechanisms:

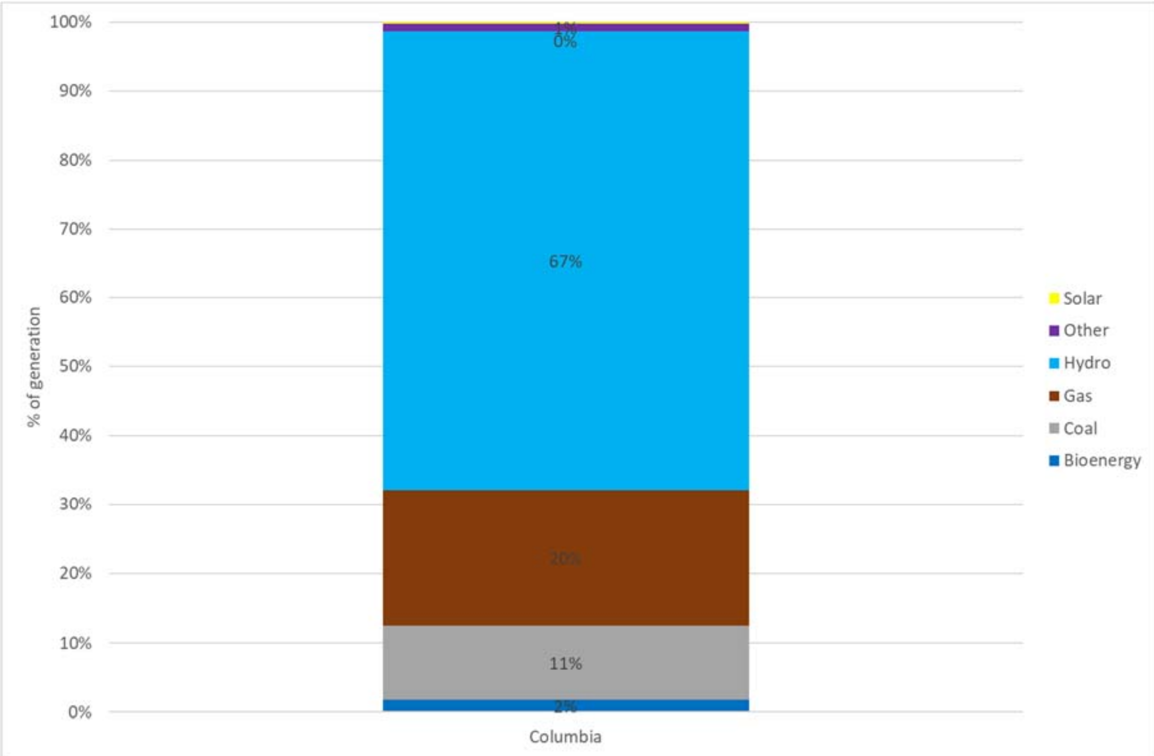
- Bolsa de Energia: A day-ahead spot market for day-to-day trading of electricity between all the generators on the market. All registered generators are mandated to participate in the spot market;
- Bilateral contracts: Bilateral contracts for long-term contracts provide the opportunity for sellers and producers to fix cost and hence minimizing their exposure to the volatile spot market cost; and
- Firm Energy Obligation Auctions: Reliability auctions for procurement of capacity in the long run.

The day-ahead spot market does not include any representation of the transmission network, so network constraints are not accounted for. Resources are ordered based on offer price, and this merit order is used to determine the 'ideal dispatch'. XM combine the ideal dispatch with network constraints to determine the actual dispatch. The point at which demand crosses the merit order becomes the reference price for settlement in the spot market and for long-term contracts. The spot price is the price of the last resource meeting the demand and clearing the market. All sub-marginal resources offered in the same hour will be remunerated. Since the actual dispatch differs from the ideal dispatch, departures from the ideal dispatch position are settled at a regulated conciliation price.

Generators and purchasers can agree bilateral contracts to reduce exposure to volatile spot prices. Unregulated users can freely negotiate contract terms (including price and quantity) while regulated users must abide by set rules that enhance competition between generators. Bilateral contracts must specify the amount of energy that will be delivered per hour for scheduling generation. Committed energy is delivered through the spot market.

There is significant market power in the Colombian market because of vertical and horizontal integration. As shown in Figure 12, hydro dominates electricity generation. Almost 70% of the total electricity generated in 2020 came from hydro sources, followed by natural gas and coal. Hydro generation is volatile and difficult to predict year by year. El Niño and La Niña weather patterns drive large fluctuations in hydro levels, and in turn that drives large fluctuations in spot market prices. Further, domestic natural gas prices are linked to international market costs, which also increases electricity price volatility. Other than hydro, renewable penetration is limited, and the capacity mechanism has not yet had time to promote significant development of intermittent generation technologies and batteries.

Figure 12: Colombia – 2020 Generation mix



3.4.2 Capacity mechanism arrangement

In the 1990s, almost 80% of the electricity generated was from hydroelectric sources. During periods of heavy rainfall, abundant hydro generation would drive spot prices to plummet, making it almost impossible for CCGTs to recover their costs. As a result, there was limited investment in new thermal plant, making the country vulnerable during periods of drought.

The first capacity payments were made using an administered price rather than an auction-based mechanism. In 2008, the administered price mechanism was replaced by a reliability mechanism with auctions to procure new capacity and to compensate existing capacity and the first auction was held the same year. The elements making up the reliability mechanism are:

- Firm energy obligation auction;
- Call option based on spot price; and
- Performance guarantees.

The Firm Energy Obligation Auction is a capacity procurement mechanism which is used to ensure sufficient capacity in dry hydrological periods.

These auctions are held three years before the delivery period. The auction takes place in a descending clock format. Generators and investors actively participate in the auction, while the demand curve is made up by price quantity pairs produced by Commission for the Regulation of

Energy and Gas (CREG). Several rounds of auction take place with each round between a pair of prices until the supplied quantity meets the demand curve.

The quantity of capacity offered by each resource cannot exceed the Firm Energy for Reliability Charge (ENFICC in Spanish) which XM calculates considering the technical aspects of the plant, forced outages, fuel availability, hydrological risk, and natural gas supply. This determines the capability of the resource during a dry hydrological period.

All generators that have cleared the market are paid monthly reliability charges based on the firm energy awarded to each generator and the market clearing price. Cleared resources receive a stable and continuous reliability revenue for:

- Existing plants – 1 year;
- New plants (not under construction during auction) – Between 1 and 20 years; and
- New plants (under construction during auction) – Between 1 and 10 years.

In exchange, generators offer their capacity during periods of scarcity.

Capacity providers must offer their service during periods when the spot price exceeds a specified call price called the scarcity price. The scarcity price is calculated by CREG and was initially set at the 95th percentile of prices from the previous eight years[23]. When the spot price exceeds the scarcity price, generators with capacity obligations must cover their firm energy commitments in the ideal dispatch[24]. During periods of scarcity, generators receive the scarcity price for each unit produced as per their firm energy obligation. If the generator produces more or less than its firm energy obligation, the difference is settled in the spot market. A generator producing less than its obligation will purchase the required energy, while a generator producing more than its obligation will be paid the spot price for the excess energy generated.

Parties can trade obligations via bilateral contracts, voluntary interruptible demand can participate, and reconfiguration auctions can be conducted to adjust the procured capacity based on market conditions.

[23] In 2015, the scarcity price was set at $470,660/MWh.

[24] Dispatch when considering a single-node network and no transmission restrictions or security constraints.

3.4.3 Issues with the capacity mechanism

Penalty regime

In 2009/2010, Colombia's capacity mechanism failed to operate as expected to deal with the dry hydrological year. While the market did manage to operate without curtailment, several concerns were raised regarding the capacity mechanism[25].

Hydro power plants prioritised honouring their bilateral energy sales commitments rather than conserving water in preparation for a dry year. Hydro owners preferred the risk of future non-performance against immediate economic loss which they would have incurred if they had purchased power in the market to meet the bilateral obligations. Because generators were not deterred by prospective penalties for under performance, regulators intervened to change dispatch order to deliver more thermal sourced electricity and reduce hydro output. Spot prices increased due to the dependence on thermal power plants, providing incentive for them to stay in the market. Despite holding firm gas supply contracts, some of the thermal plants did not receive sufficient gas supply due to pipeline capacity constraints. Some could switch to liquid fuel but did not have supply infrastructure in place.

The intervention could have been avoided by enforcing stricter policy regimes for future non-Compliance Of Obligation (OEF) incentivizing owners to conserve more hydro reserves to prevent potential future charges. This could have also mitigated the fuel shortage issue leading to reduced power output from thermal power plants by encouraging thermal plants to sign firm fuel supply contracts and making sure suppliers deliver the fuel according to the contract by reinforcing the pipeline network.

This illustrates the issue with establishing 'firmness' of supply over extended periods of time. Resource adequacy depends not just on nameplate rating and weather patterns, but also on fuel supply, transmission network resilience, and commercial behaviour.

Market power in the auction process

The first auction in May 2008 led mostly to existing plants securing capacity – only three of ten prospective new plants were awarded capacity. In the second auction held in June 2008, the information on demand and supply conditions released between the rounds caused one bidder to realise that it was pivotal in the auction. It acted on that market power, withdrew one of its offers, drove the capacity market clearing price up and increased its profit.

[25] Learning from Developing Country Power Market Experiences: The Case of Colombia

Two responses were identified:

- Increasing the slope of the demand curve to reduce the potential for market power abuse, as strategic bidders would then have to make a trade-off between pushing up the price with a lower accepted volume.
- Hiding the true demand curve to reduce bidders' ability to discern if they are pivotal while still providing intra-round information, by adding an artificial tolerance band or sharing only a range of excess supply information instead of the exact volume.

In the 2011 auction, the regulators reduced the amount of information on demand and supply revealed during the auction, but the auctioneers ultimately abandoned the auction due to concerns that the pivotal generator was likely to exercise market power again after two rounds and a sealed bid auction was held in its place.

Insufficiency of administered scarcity prices

In 2014-15, the scarcity prices (the price at which reliability obligations become operative) dropped to 302.43 COP/kWh (302,430 COP/MWh) following the monthly indexation to the price of fuel oil as the oil prices fell[26]. This coincided with an El Niño event causing droughts, fuel shortages and increased demand. As the variable cost of thermal resources was higher than the scarcity price at that time, reliability providers were making a loss whenever required to generate. CREG again intervened in the market to set a new scarcity price (470,660 COP/MWh) for thermal power plants operating with liquid fuels. This reduced their operating loss, and the higher prices were passed on to end consumers.

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[26] Colombia Firm Energy Market

3.5 United Kingdom

MARKET INFORMATION	
Energy Market	
Gross vs Net pool	Net pool
Trading interval	30 minutes
Locational pricing	No
Day ahead market	Yes
Real time market	Yes
Interties	Yes
Capacity mechanism	
Procurement structure	Capacity market with auctions
Additional features	Bilateral trading
Auction type	Voluntary centralized descending clock auction
Resource adequacy requirement	Local requirements based on LOLE which is 3 hours per year
Timeline	There is a four-year-ahead auction followed by a year-ahead auction
Price information	Sloped demand curve with a price cap of GBP 75,000/MW (2014). 95% target capacity at price cap and 105% target capacity where price reaches zero
Intermittent in capacity mechanism	Prohibits RE support when participating in the capacity market

3.5.1 Market Structure

The Electricity Act of 1989 de-regulated the UK electricity market paving the way for privatization of sector participants. A capacity market was introduced in 2014 to contain price volatility and attract entry of efficient resources to provide supply during periods of system stress. The mechanism is administrated by National Grid Electricity System Operator (NGESO), under the oversight of the Office of Gas and Electricity Markets (Ofgem). NGESO is also responsible for matching the demand and supply second by second. The wholesale market is designed as a net-pool arrangement where the NGESO attempts to schedule generators according to their desired output. This self-scheduled position is notified to NGESO which runs a voluntary balancing mechanism to account for network issues and match supply and demand via increments and decrements around the scheduled positions.

UK electricity generation is now transitioning from a large-scale, conventional fossil-fuel dominated generation mix to renewable generation such as wind and solar farms. Electricity and gas can be imported or exported through interconnectors. Between 2010 and 2019, the share of renewable generation in total electricity generation in the UK increased fourfold, and in 2019 renewables contributed 37.1% of total electricity generation. National Grid ESO's 2020 Future Energy Scenarios estimate that 42% of the generating resources in UK will be connected to the distribution network leading to a large-scale decentralized network[27].

The UK has one of the highest wholesale market prices for electricity in the world, close to USD 120/MWh. In 2019, the installed capacity was close to 79 GW which was 31% higher than the peak demand during the same year (60 GW). Generation is dominated by gas as the primary fuel, making up 41% of the total generation followed by wind and nuclear energy. More than 90% of electricity is generated from low-emission sources due to the abundance of gas supply. Electricity prices are highly correlated with gas prices.

27 National Grid ESO. Future Energy Scenarios

Figure 13: UK 2019 Installed Capacity vs Peak Demand

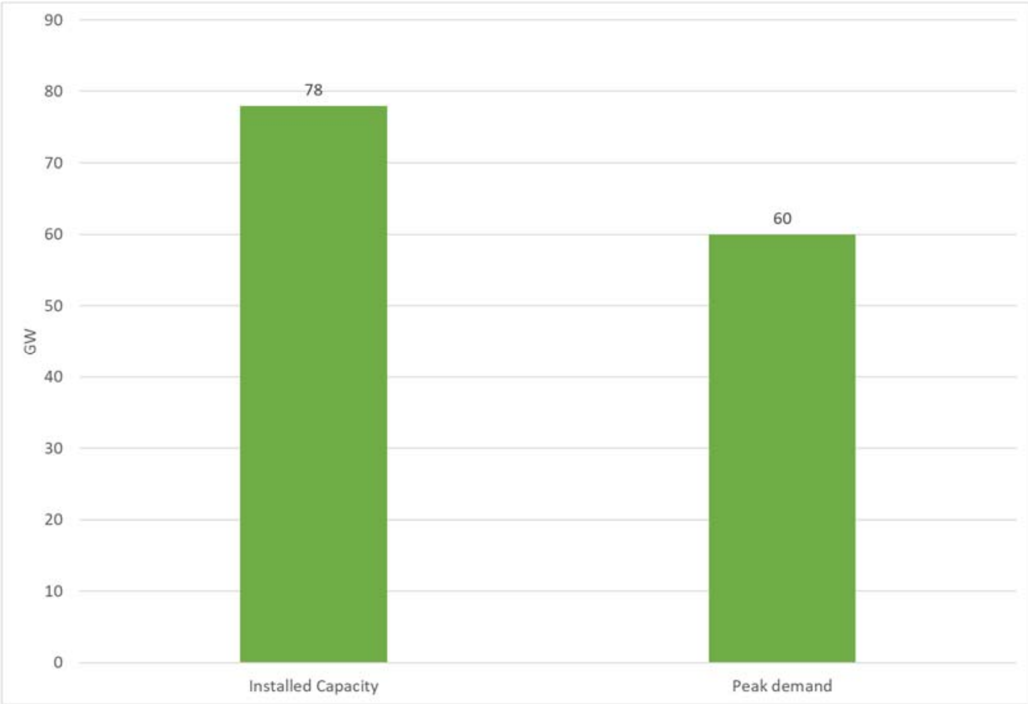
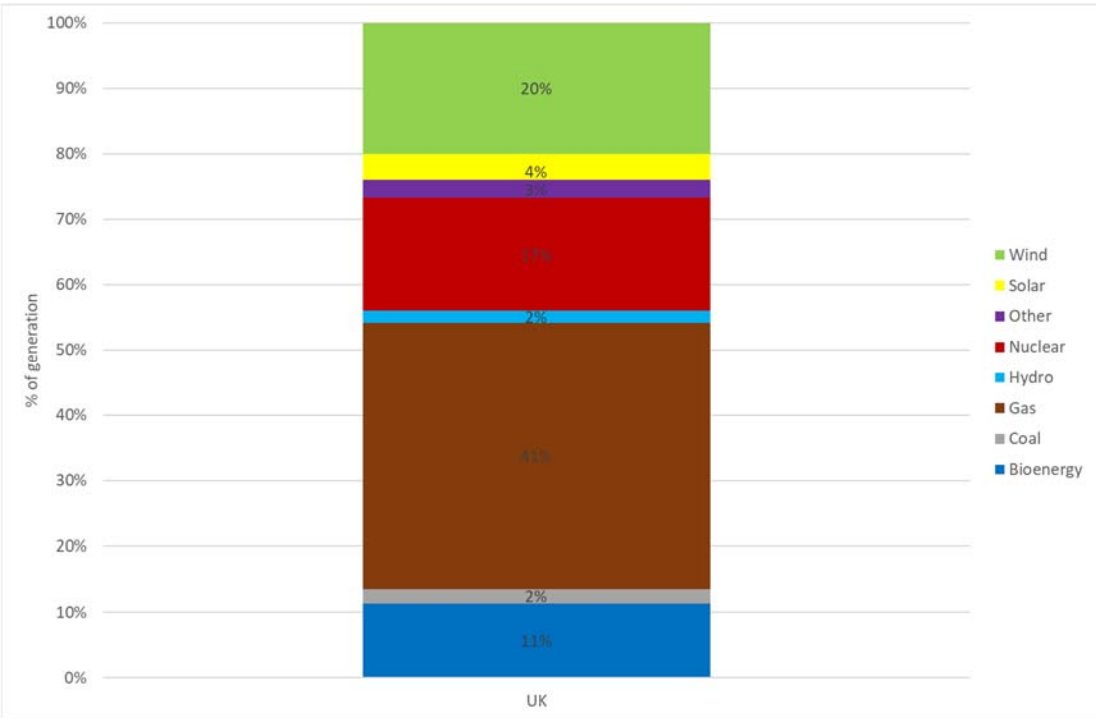


Figure 14: UK – 2020 Generation mix



3.5.2 Capacity mechanism arrangement

The UK capacity mechanism is intended to ensure security of electricity supply at the least cost to consumers by providing the right incentives to capacity providers to deliver power when needed, especially during system stress periods. Eligible capacity providers bid into the competitive capacity auction, and successful capacity providers are obliged to provide the agreed capacity when needed. Capacity providers receive steady payments in exchange for their availability to meet demand at times of system stress. The capacity payment is supposed to maintain and refurbish existing capacity as well as to finance new capacity when and where necessary. Bilateral trading also takes place between parties to adjust their position based on market conditions.

The capacity market was first introduced in 2014 and procured 50 GW of derated capacity[28]. The first auction is held 4 years prior to the delivery period (T-4) followed by a supplementary auction 1-year ahead of delivery. The reliability criterion is based on a LOLE of 3 hours per year. Network constraints are not accounted for, and there is no locational differentiation – it is a nationwide market. If necessary to manage constraints, National Grid can run zonal auctions, but must have approval from Ofgem before doing so.

The capacity mechanism is run in a descending clock format with 'pay-as-clear[29]' structure. The auction starts at £75,000MW/year and prices gradually reduce until a point where the supply of capacity offered meets the volume required. This price cap of £75,000/MW/year is set based on 1.5×Net CONE. Net CONE is calculated as the price equal to the procurement of a new Combined Cycle Gas Turbine (CCGT) investment above the expected revenue earned in the market. The clearing price at the first T-4 auction was £19,400/MW/year[30]. The hourly penalty rate for non-compliance is 1/24th of the respective auction clearing price.

Facility providers are classified broadly into two types – price takers and price makers. Almost all facility providers are price takers. These facilities are not expected to incur building costs for rolling out new capacity and are required to only bid below a certain price threshold. New entrants and Demand Side Response (DSR) resources are classified as price makers and can bid up to the price cap as described by CONE. DSR resources are also eligible to participate in intermediate auctions before the main auction, to stimulate investment in that class of resources.

One year Capacity Agreements are offered to existing plants. Capacity Agreements of up to three years are offered for existing plants that can demonstrate that they require major refurbishment (Refurbishing CMUs). New plants or those with certain new build elements (New Build CMUs) can access contracts up to a maximum of 15 years.

The image below from the Department of Energy and Climate Change (DECC) outlines the mechanism for capacity procurement.

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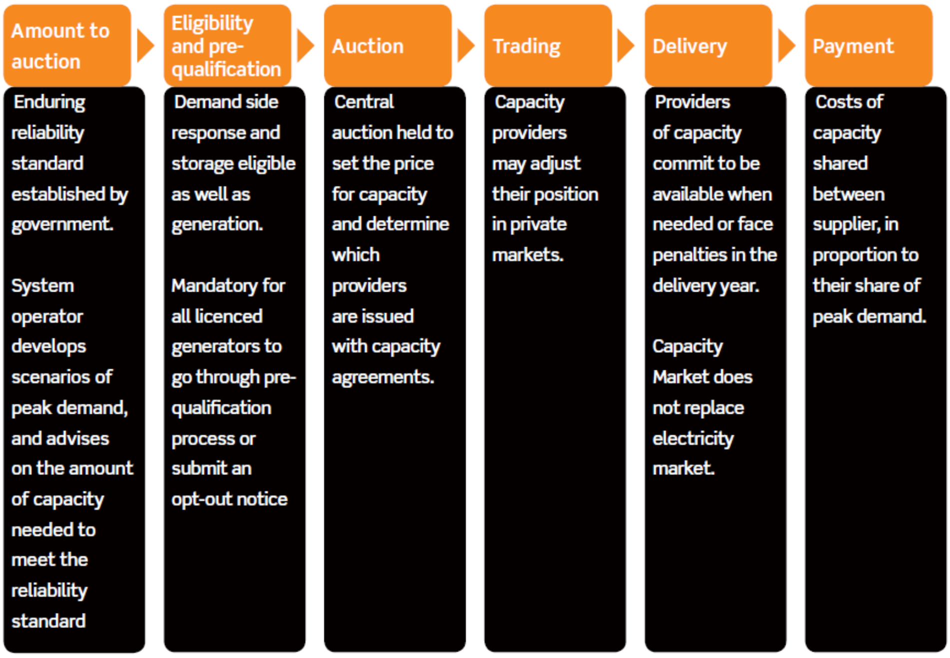
[28] UK Capacity Market

[29] 'Pay-as-clear' means participants will be paid the market clearing price set by the marginal bidder.

[30] Why low UK capacity prices come at a cost

Figure 15: UK Capacity Auction process (DECC)



Source: DECC

Determining capacity contributions

The LOLE target in the UK is 3 hours. The market does not differentiate between technology types i.e. there is only a single capacity product, and the auction does not seek to procure allocated volumes from specific technology types. However, there are restrictions on how different resource types can participate in the auction. Intermittent renewable generators cannot participate in the capacity mechanism if they receive subsidies from other state funded schemes.

All capacity facilities are derated to account for unplanned plant closure or maintenance. Rather than calculating the availability of each individual resource, derating is conducted on a facility class basis. This derating factor is based on the ability of the facilities in the class to provide capacity during periods of system stress in the year under consideration. Imports through interconnectors (both existing and new) are allowed and are additionally derated to account for interconnector performance.

Table 1 shows availability ratings for resource classes in the UK.

Table 1: Availability ratings for different technologies

Fuel type	Winter availability	Summer availability
Coal (and biomass)	87%	61%
Gas CCGT	86%	69%
OCGT	77%	63%
Gas CHP	86%	89%
Hydro	92%	84%
Pumped storage	95%	95%
Nuclear	83%	71%
Oil	81%	47%
Wind[31]	20%-22%	11%

3.5.3 Issues with the capacity mechanism

The two major areas of concern expressed in the UK capacity mechanism to date have been:

- The perceived over-procurement of high-emissions thermal capacity and dampening of on-peak load pricing in the wholesale spot market.
- Perceived barriers to participation of demand side resources.

Advantages for incumbent resources

The results of the first T-4 auction showed that the mechanism as originally designed was more likely to support incumbent diesel and gas fired power plants than new renewable generation. 11,250 MW of new capacity bid into the auction, and only 2,600 MW cleared. One new CCGT of 1650 MW capacity cleared the auction but withdrew after failing to raise finance. A large volume of distribution connected Open Cycle Gas Turbines (OCGT) and small (~10 MW) diesel power plants cleared the auction. This distribution connected generators were not subject to Transmission Network Use of System (TNUoS) charges which transmission connected facilities must pay. Although the capital costs of such facilities were low, and the high running cost would only be incurred during system peak demand, there was general concern that the capacity mechanism favoured inefficient plants rather than cleaner, more efficient CCGTs. Further, at the first T-4 auction, interconnectors were not allowed to participate.

[31] Wind availability calculated using Equivalent Firm Capacity (EFC) method. An EFC is defined as the precise amount of perfectly reliable firm capacity a resource can displace while maintaining the exact same level of risk on the system. EFC can be defined with respect to either the LOLE or the EUE risk metric (as can ELCC).

While the capacity mechanism was able to procure the required capacity at a relatively low price, the mix of capacity that cleared the auctions may not have done so at the lowest overall economic cost once environmental considerations were included. Environmental organizations were not happy with coal and diesel receiving capacity payments. DSRs saw the Capacity Mechanism as unbalanced and undermining their main potential market of responding to scarcity pricing in the wholesale market. DSR owners argued that the price and the true economic cost were not aligned as the transmission and the distribution tariffs failed to provide the right economic signals to inform efficient location decisions.

Diesel generators were effectively barred from entering the auction in 2016 by new environmental and emission standards. Embedded generation still dominated the winning bids in the subsequent auctions, though with more battery participation.

Participation of demand response

In the UK capacity market, new generation and demand response are awarded different length contracts. All participants in the auction are eligible for one-year contracts, while longer contracts are available for resources whose capital expenditure is more than £255,000/MW. Demand response does not fulfil this criterion. As a result, successful new entrant demand response providers can only get a one-year contract, while successful new entrant generators are eligible to be awarded contracts for up to 15 years.

Longer contracts provide assurance of stable revenue on which a new entrant can build a business case, secure investment in the development of new technology, and enter the market on a sound footing. DSR proponents argue that a one-year contract does not guarantee sufficient time to develop and install a new demand response technology, and DSR providers are therefore at a disadvantage to new supply, even though demand shifting should be a more efficient overall approach. They have proposed adjustment or removal of capital expenditure thresholds for contract length eligibility, with all new entrants able to bid for contracts up to five years long.

3.6 IRELAND

MARKET INFORMATION	
Energy Market	
Gross vs Net pool	Gross pool
Trading interval	30 minutes
Locational pricing	No
Day ahead market	Yes
Real time market	Yes
Interties	Yes
Capacity mechanism	
Procurement structure	Capacity Remuneration Mechanism – Reliability Options
Additional features	Bilateral trading with reliability options
Auction type	Central buyer uniform price sealed bid auction with locational network constraints
Resource adequacy requirement	Local requirements based on LOLE which is 8 hours for Ireland and 4.9 hours for Northern Ireland
Timeline	There is a four-year-ahead auction followed by a year-ahead auction
Price information	Sloped demand curve with price cap at 150% of CONE. 100% of target capacity at price cap, then target capacity at 100% CONE and finally zero price at 115% target capacity
Intermittent in capacity mechanism	Diminishes RE revenue when participating in the capacity mechanism

3.6.1 Market structure

The Irish Integrated Single Electricity Market (I-SEM) covers the whole island of Ireland, including both the Republic of Ireland and Northern Ireland. Before 2007, the two jurisdictions were operated separately, with Northern Ireland managed as a part of the UK electricity market. In 2007, the two system operators (System Operator Northern Ireland (SONI) and EirGrid) cofounded the Single Electricity Market Operator (SEM-O). SEM was designed to provide access to electricity at least cost across the whole island. The SEM is a mandatory gross pool market. This meant that all electricity that is generated, consumer, imported or exported must be sold and purchased through SEM.

Electricity in the Republic of Ireland is regulated by the Commission for Regulation of Utilities while in Northern Ireland, it is regulated by Northern Ireland Authority for Utility Regulation. EirGrid and SONI operate the transmission systems in their respective markets. Ireland is a part of the Europe wide European Network of Transmission System Operators (ENTSO-E) and has interconnections with UK which connects them to rest of the EU. SEM is integrated with the other EU market (via Great Britain) using the Europe-wide Single Day Ahead Market Coupling mechanism.

Since 2017, the I-SEM comprises:

- Day-Ahead Market (DAM);
- Intra-Day Market (IDM);
- Balancing mechanism; and
- Capacity Remuneration Mechanism (CRM).

The CRM replaced a previous capacity payment scheme which provided payment to all facilities and seeks to promote more renewable and demand side participation in the wholesale market.

The installed capacity in Ireland is 16.8 GW which is significantly higher than the peak demand (6.8 GW) in 2019. This is due to both a high penetration of low capacity factor wind generation, and to locational constraints accounted for in the CRM (see below). Like the UK, electricity generation is dominated by gas (51% of electricity produced in 2020), followed by wind (36%). From 2019 to 2020, the renewable share grew by 14.3% due to an increase in wind production and a huge fall in peat generation[32].

Ireland trades with Europe using two interconnectors – the East West interconnector between Wales and Ireland, and the Moyle interconnector between Northern Ireland and Scotland. Given the size of the grid, imports from a major portion of Ireland's electricity supply. Ireland is a net importer of electricity from UK, and Northern Ireland is a net electricity importer from Ireland.

[32] How Ireland is abandoning its dirty fuel-BBC

Figure 16: Ireland 2019 Installed Capacity vs Peak Demand

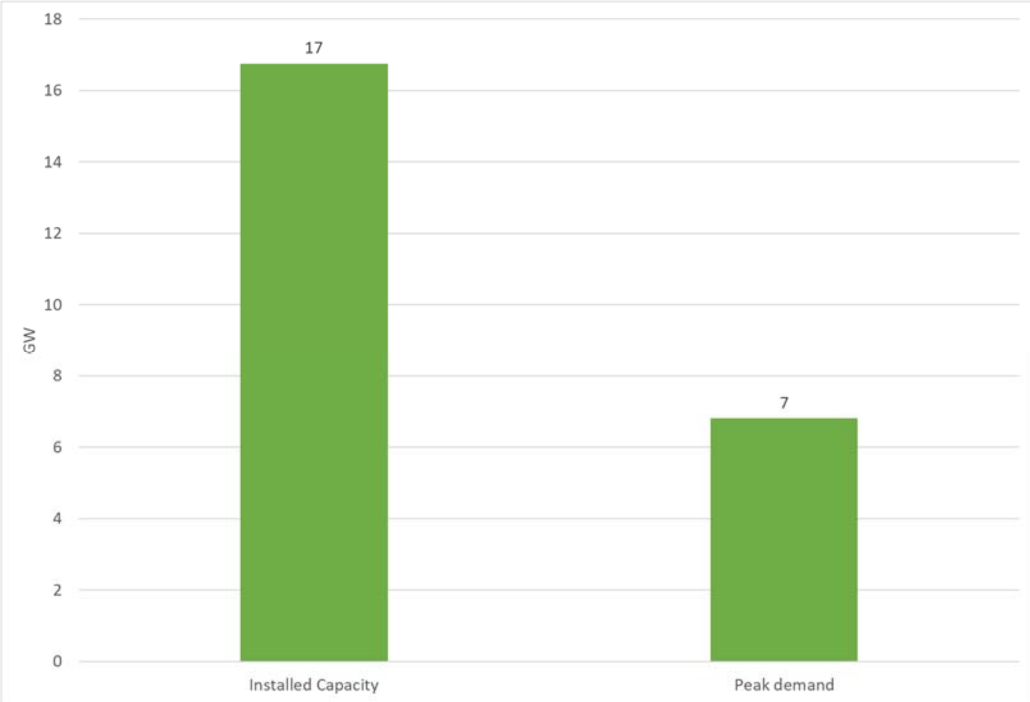
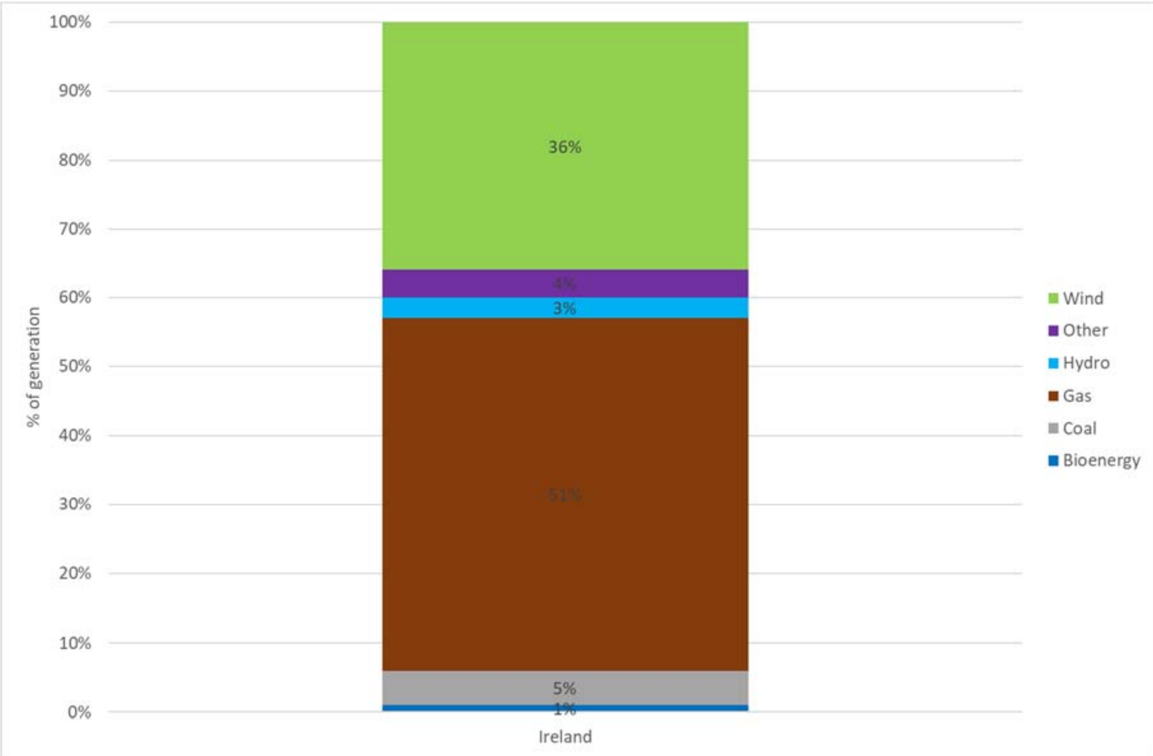


Figure 17: Ireland 2020 Generation mix



[33]

3.6.2 Capacity mechanism arrangement

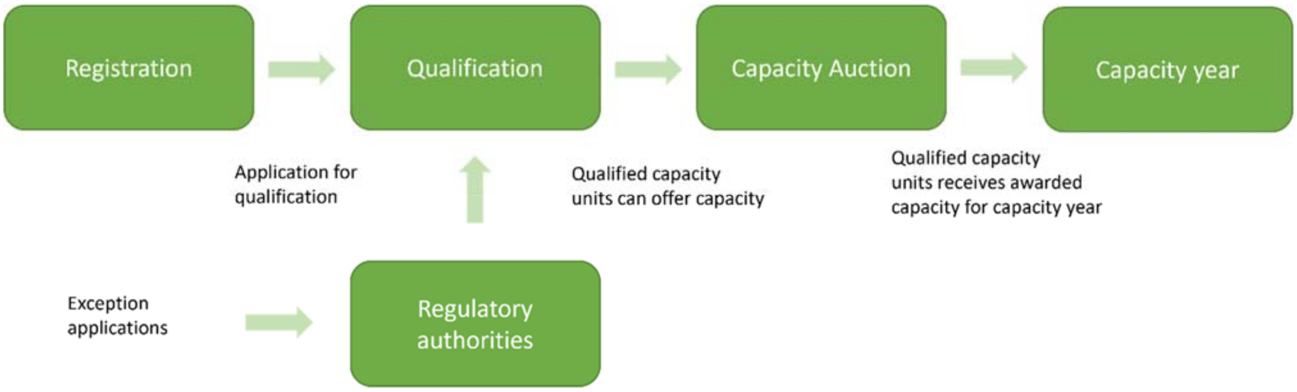
Ireland's current CRM went live in 2017. It is a central buyer capacity mechanism using volume-based reliability options.

SEM uses a reliability option which is a one-sided Contract for Differences (CfD). The capacity provider is committed to a payment that is the difference between the market price and a set strike price. The strike price is set such that it is at or slightly higher than the marginal cost of the peaking plant so that the cash flow captures the scarcity rent that would be earned by the providers when the capacity of the peaking unit is exhausted. The reliability option provides capacity suppliers the opportunity to swap the risky scarcity rent with a predictable capacity payment. In turn, consumers are protected from the price spikes in return for a fixed rate of payment.

The auctions are conducted as a sealed bid combinational auction with uniform clearing price organized by the System Operator SEM. Bids are submitted into the auction simultaneously by resource providers, and each bidder knows only its own bid. Multiple bids from a single resource are allowed, but only one will be cleared. Like the UK, there is an initial auction 4 years ahead of delivery followed by an auction a year ahead.

[33] The sum of the percentages may not add up to 100% due to rounding off

Figure 18: SEM capacity mechanism (adapted from SEM committee website)



The reliability criterion is based on a LOLE of 8 hours for Ireland and 4.9 hours for Northern Ireland. Northern Ireland assumes a 200 MW capacity reliance on Ireland while Ireland assumes a 100 MW capacity reliance on Northern Ireland

CONE is calculated based on a new flexible CCGT. A sloped demand curve is developed based on net CONE and the reliability target. The price cap for the CRM auction is set at 150% of CONE.

Bids are arranged from lowest to highest based on price until the capacity requirement for the capacity year is satisfied.

CRM accounts for locational constraints. This ensures that a minimum quantity of de-rated capacity is cleared in the auction in each area where constraints are identified in the network. This means that additional capacity or more expensive capacity may be procured than otherwise would be if the network was considered unconstrained.

Determining capacity contributions

Like the UK capacity mechanism arrangement, capacity is derated to consider the probability of forced outages. Derating is based on historic performance data, but sometimes expected changes in future performance can be accounted for. Facilities with higher reliability will have a smaller derating, meaning they can offer a larger share of their installed capacity into the auction. Interconnectors, demand response, existing capacity, new capacity, and storage can all bid in the auction. All qualified capacity, except intermittent and new entrant resources must bid into the auction.

For variable intermittent like solar and wind, whose availability is highly correlated, the derating is based on entire class of the resources rather than individual units. The availability of the wind technology class is based on the actual output of all wind units relative to their installed capacity and defines a profile of wind generation for a year.

Energy storage resources are de-rated according to technology specific curves and facility specific storage duration. Pumped hydro storage units have a set of de-rating curves based on historical outage statistics, and new storage types (such as batteries, compressed air, and flywheels) have a different set of curves based on system wide outage statistics. When capacities of equal economic and technical circumstances are competing in the auction, low emitting technologies are favoured.

Renewable capacity may receive revenue from other support schemes. In the Republic of Ireland, capacity revenue is deducted from Renewable Energy support payments, while in Northern Ireland, Renewable Obligation Certificate holders cannot participate in the capacity mechanism to prevent double subsidization.

3.6.3 Issues with the capacity mechanism

Market concentration

Given the small size of the Irish market and the relatively large size of each generator, most capacity providers have market power. This is exacerbated by the necessary inclusion of locational distinctions in procuring capacity.

In 2018, Viridian offered both units in its 744MW Huntstown gas-fired power plant north of Dublin into the T-1 capacity auction. Only one unit cleared. Viridian indicated that without the reliability options for both units, it would not make economic sense for them to run the plant, and it formally provided the required three-year notice of closure[34]. Since no new capacity was procured in that auction and the generation unit formed a significant source of supply for that area, it was necessary to keep the generating unit running to ensuring security and reliable supply for Dublin. The SEM Committee and EirGrid/SONI assessed the possibility for the generating units to be viable without the reliability options and agreed with Viridian's analysis. The Commission of Regulation of Utilities (CRU) reached an agreement with Viridian outside the market to keep both the units for the plant running for the next 3 years.

This shows the issues faced in a small market with a small number of large generators. Although the capacity auction in Ireland has secured capacity for consumers at low cost, the failure of a single market participant can cause an instability in the market. Ireland has since focused on removing barriers to entry, and ensuring incumbents have the right incentives to remain or exit.

Incentivizing renewable participation

All resource types, including intermittent renewables, can participate in the auction, even if they are entitled to state funding or other state support. While this provides another potential source

[34] Transition to a Capacity Auction: A Case Study of Ireland

of revenue for renewable developers, they must effectively choose either capacity revenue or other state programmes.

Under the current CRM arrangement, generators are rewarded based on their availability to provide generate during periods of high demand. If a renewable generator with capacity obligations does not perform during periods of system stress, it is subjected to penalties which include paying back the entire market reference price for its obligation volume for that period. Under other programmes, renewable generators face fewer obligations and less risk of penalty.

In addition, the use of resource-class-wide derating factors means that the capacity obligation for a particular renewable resource may be greater or less than a facility specific derating factor would provide, and as a result, some intermittent generators choose not to participate in the capacity mechanism. By opting out, they avoid the risk of not being able to deliver their (centrally set) derated capacity quantity during those periods, while still receiving the same net revenue from other support schemes.

Non-participation of renewable resources in the capacity mechanism increases the likelihood of incumbent fossil-fuelled resources clearing the auction, receiving capacity payments, and delaying retirement.

4 CONSIDERATIONS FOR THE WEM

This chapter discusses how the issues identified in other markets could apply to the WEM.

We identified five themes relevant for the WEM in the issues faced in other markets:

- The potential for capacity market settings to work against decarbonisation (PJM, UK, and Ireland);
- Single-dimension reliability criteria do not work as well in high intermittent penetration environments (PJM and ISO-NE);
- Alternative methods to better approximate capacity contribution of intermittent resources (PJM, ISO-NE, UK);
- Issues arising from a non-diverse generation fleet (ISO-NE, France, Colombia, and Ireland); and
- The WEM demand curve is significantly shallower than that used in other markets.

Finally, we identified a range of other design differences, some of which could be considered in the WEM.

Each section below sets out the issue, examples from other markets, and application for the WEM.

4.1 CAPACITY MARKET SETTINGS CAN WORK AGAINST DECARBONISATION OBJECTIVES

The WEM is amid transition from predominantly grid-connected fossil-fuelled generation to distributed renewable generation. The WA government has expressed a goal of being net carbon neutral by 2050. To achieve this goal, the energy sector transition must continue. As a key revenue stream for new and existing generation facilities the RCM must, at minimum, not hinder decarbonisation of the electricity sector, and could also play a significant role in supporting decarbonisation.

While all the markets studied are also working to increase renewable generation, several have faced challenges where the design of the capacity mechanism has hindered this goal.

4.1.1 PJM

PJM's Minimum Offer Price Rule requires new facilities to offer into the capacity auction with a minimum price calculated with respect to their total capital costs. This rule was initially envisaged as a market power mitigation measure, to avoid vertically integrated entities offering new generation at artificially low prices to reduce the overall capacity price. With the introduction of state-level subsidies for renewable generation, new wind and solar plant is forced to offer capacity at a price that recovers all its costs, rather than its costs less the state subsidy. As a result, capacity prices are higher than they would be otherwise, meaning that less efficient (and potentially more polluting) facilities clear the capacity auction instead.

4.1.2 UK

In the initial UK capacity auction, a high proportion of embedded diesel fuelled generators cleared, as they could offer at prices lower than transmission connected facilities through avoiding transmission-use-of-system charges. If repeated over time, this would likely have resulted in an increase in overall emissions intensity rather than a decrease. In subsequent auctions, eligibility requirements for capacity credits were tightened to include strict emissions criteria.

While the UK does not explicitly procure different types of resources, its cost-based rules for multi-year contracts mean that demand side resources are only eligible for one-year contracts. This differential treatment could distort efficient outcomes given that Demand Side Programmes are often the most cost-effective source of peak shaving.

4.1.3 Ireland

The Irish market (like the UK) derates capacity providers on a class basis rather than an individual facility basis. This means that renewable facilities which have a different output profile than the class as a whole are more likely to face penalty payments for not meeting capacity obligations. At the same time, capacity payments to renewable generators are netted out of their government subsidy payments, so there is limited upside in joining the capacity mechanism. As a result, some intermittent generators do not participate in the capacity mechanism, and other generation is procured instead.

4.1.4 WEM

In the WEM, as in other markets, capacity payments generally act to extend the life of existing facilities. Because the incumbent WEM generation fleet receiving capacity payments is primarily fossil-fuelled, this has potential to temper the competitiveness of new renewable capacity in the SWIS. Though new resources can still enter the WEM to provide energy and ancillary services without entering the capacity market, it will take longer to recover the capital cost of their resource, potentially delaying the transition. While pricing methodology is out of scope for this review, we need to look closely at the impact of capacity payments on the viability of renewable generators.

Demand Side Programmes are not eligible to be considered as fixed price facilities in the WEM, and hence can only receive one year's worth of price certainty.

The UK experience shows that the WEM could consider emissions parameters for capacity eligibility.

4.2 An effective reliability criterion must consider different dimensions of unserved energy

The reliability criterion is the key determinant of the required capacity.

In most power systems, the risk of unserved energy has historically been highest at times of peak demand. Consequently, reliability criteria have largely sought to provide sufficient capacity to meet peak demand. This made sense when the generation fleet was primarily traditional thermal generation: if it is available to serve the peak, it should be available to serve off-peak.

As the proportion of intermittent renewables increases, the risk profile is changing, with increased risk of unserved energy in hours outside the peak period, as traditional planned outage periods coincide with seasonal variation in wind and solar resources.

4.2.1 Dimensions of reliability events

Energy Systems Integration Group's 2021 paper[35] included Figure 19, providing examples of different types of reliability events.

[35] https://www.esig.energy/resource-adequacy-for-modern-power-systems/

Figure 19: Dimensions of resource adequacy[36]

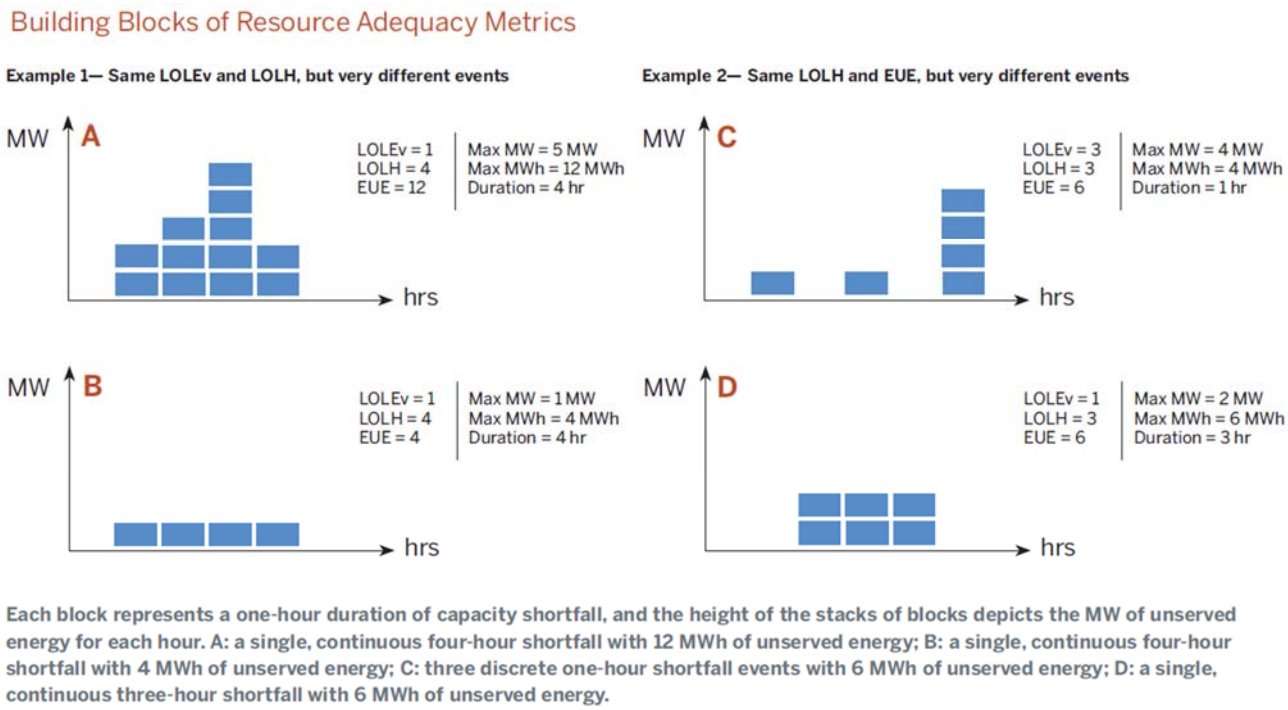


Figure 19 A and B show two events with same LOLEv and LOLH but with different Expected Unserved Energy (EUE). Event A has EUE three times higher and maximum unserved energy five times higher than event B. Figure 19 C and D show two events with similar LOLH and EUE but with different LOLH. Event C has three distinct events while event D has a single shortfall event of equal magnitude. The maximum unserved energy is higher in C than D (4 MW vs 2 MW respectively).

The different kinds of shortfall event will be best served by different technology configuration. For example, storage resources can assist in all types of events, but more stored energy would be needed to deal with event A than event D, which in turn would require more stored energy than B and C.

Table 2 shows the reliability criteria in the studied markets. As noted above, they all use a one-dimensional measure.

[36] Redefining Resource Adequacy for Modern Power Systems - Energy Systems integration group

Table 2: Reliability criteria in studied markets[37]

Jurisdiction	Reliability Criterion
PJM	0.1 events per year
ISONE	0.1 events per year
France	3 hours per year
UK	3 hours per year
Ireland	8 hours per year for Ireland, 4.9 hours for Northern Ireland

PJM is investigating changes to its reliability criterion to recognise the different dimensions of risk.

None of the studied jurisdictions considers low load in its reliability criterion.

4.2.2 WEM

The current WEM planning criterion has two limbs. There must be enough capacity to avoid:

- Any unserved energy in a 1-in-10-year peak load event (including an allowance for outages and essential system services); and
- Unserved energy across the year of more than 0.002% of total demand.

Historically, only the first limb has ever bound.

The two-limbed WEM approach is already more flexible than other markets, accounting for two of the three dimensions of unserved energy, but does not distinguish between frequent shallow outages or infrequent deep outages (e.g. events A and C in Figure 19).

Unlike the markets studied, the SWIS has issues with low load during periods of high solar availability[38]. This distributed solar PV is a non-synchronous generation source which does not contribute to maintaining system frequency or provide system inertia, and accommodating it displaces synchronous generation which can provide those services.

[37] We were unable to identify the specific criteria used in Colombia.

[38] https://aemo.com.au/en/energy-systems/electricity/wholesale-electricity-market-wem/system-operations/integrating-utility-scale-renewables-and-distributed-energy-resources-in-the-swis

The system stress modelling conducted as part of the RCM review will inform the type of events to be expected in the WEM, and hence which event dimensions are most important.

4.3 Alternative methods for certifying capacity are available

Different markets use different methods for determining the reliability contribution of eligible resources, with different approaches for different technologies. Firm generation is assessed based on claimed maximum capacity – sometimes adjusted for expected outage rates – while intermittent generation and storage are derated to reflect the uncertainty of their contribution.

Of particular interest are the methods different to those used in the WEM.

4.3.1 PJM

PJM currently measures the reliability of intermittent resources using Equivalent Load Carrying Capacity (ELCC). A resource's ELCC value measures the difference between the load the system could serve with and without the resource, while maintaining the same reliability target. This probabilistic method considers the contribution of the resource across time (peak, shoulder, and off-peak), accounting for the generation profile, correlation with other resources, and any storage available. While the method is promising, there are still issues that the market is trying to address like accurately calculating the contribution of individual facilities, reducing the complexity of the method and the availability/accuracy of historical data.

ELCC can be defined in relation to any of the dimensions of resource adequacy – number of events, hours of outage, or expected unserved energy.

4.3.2 ISO-NE

ISO-NE determines capacity contributions for conventional generators using their maximum rated output, and for intermittent generators using the seasonal median output during specific hours.

ISO-NE is concerned that certification based on maximum output does not account for slow ramping or long start-up units, and that certification based on seasonal median output does not account for correlation with other resources.

As a result, ISO-NE is now investigating use of a Marginal Reliability Index (MRI) to assess capacity. MRI applies the same philosophy as ELCC, in that it seeks to estimate how the incremental addition of the resource affects the overall reliability of the system. The difference in load for maintaining the system reliability at the same level with and without the candidate facility is used to calculate the ELCC value while MRI is calculated as the difference in reliability value when replacing the intermittent facility with firm capacity.

4.3.3 UK

While the UK determines the capacity contribution of intermittent generators for the class of resources rather than an individual resource, it uses the Equivalent Firm Capacity (EFC) method to determine the class contribution. EFC is the quantity of perfectly reliable firm capacity a resource can displace while maintaining the exact same level of risk on the system. This is similar to ELCC but instead of adding load, firm capacity replaces the intermittent capacity.

4.3.4 WEM

In the WEM, conventional non-intermittent generators are awarded CRC based on nameplate generation capacity while intermittent generators are awarded based on their historic output during system net peak periods through the Relevant Level Method (RLM).

The RLM accounts for correlation between resource outputs by assessing output in net peak periods (those with highest generation by non-intermittent resources), but CRC allocation to conventional generators does not explicitly account for ramp rates and start-up times. AEMO has discretion to reduce assigned CRC based on poor outage performance, but to date has not exercised this ability.

In its most recent review of the RLM[39], the ERA explored alternative methods, and recommended development of a numerical model to better assess the contribution of renewable resources in its Rule Change Proposal[40]. The Rule Change Panel proposed an alternative method in its Draft Rule Change Report[41] and proposed some options to address perceived weaknesses with the proposal in an Extension Notice published on 30 June 2021.[42]

As envisaged in ISO-NE, a model-based method could potentially be extended to other types of resource, providing a single capacity assessment methodology for all resource types.

4.4 A DIVERSE SUPPLY MIX IS A MORE RELIABLE SUPPLY MIX

Several markets studied had issues arising from heavy reliance on a single resource type. This is not solely attributable to capacity mechanism design, but as a major revenue stream, capacity payments have the potential to help or hinder a diverse supply mix.

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39 Relevant level method review 2018

40 https://www.wa.gov.au/system/files/2021-05/RC_2019_03----Rule-Change-Notice-and-Proposal.pdf

41 https://www.wa.gov.au/system/files/2021-05/RC_2019_03-Draft-Rule-Change-Report.pdf

42 Microsoft Word - RC_2019_03 -- Extension Notice (30 June 2021) v3.0 - FINAL (www.wa.gov.au)

4.4.1 ISO-NE

Gas supplies more than 50% of total electricity generated. The system has run near capacity during peak winter demand periods, and most generators buy their gas on the spot market rather than signing long term contracts.

To date, this reliance on gas has not resulted in price spikes or correlated unavailability in the market, but it has come close, and is a source of concern for the ISO.

4.4.2 France

France's reliance on nuclear power (more than 75% of electricity production) resulted in a rapid shift from energy exporter to importer when five facilities were shut down due to the same technological issue.

4.4.3 Colombia

Colombia's dependence on hydro resources was a primary driver for the introduction of the capacity mechanism in the first place. The issue is different to most markets, as Colombia has sufficient capacity to meet the peak, but without sufficient stored water, will run out of energy in dry hydrological years.

4.4.4 Ireland

Ireland's supply mix issues relate to resource size. A single two-unit (343MW and 401MW respectively) gas fired facility can serve 20% of total market demand. When one unit failed to clear the capacity mechanism, and the owner wanted to retire both, the regulator had to intervene and grant capacity payments to both units.

4.4.5 WEM

The WEM generation fleet primarily consists of gas and coal, which provided over 80% of the total supply in 2020. The WEM also has a high proportion of distributed solar PV generation, the output of which is correlated with utility scale solar. Wind supplied 15% of electricity 2020, and most wind generation is located in the North Country region, and this lack of locational diversity means its output is also highly correlated. With signalled exits of coal-fired capacity, the system will become even more reliant on gas generation as the main firming resource (though the preponderance of long-term contracts means the risk is lower than in New England). As the 2050 net zero target approaches, gas fired capacity can also be expected to exit, and intermittent resources become the overwhelming source of energy.

The RCM will be an important mechanism to support entry of new firming capacity in the form of storage, demand side response, aggregated distributed resources, and cleaner thermals (e.g., green hydrogen, or oxy-fuel combustor with CCS).

WEM characteristics mean it is less open to the kind of situation faced in Ireland, as all qualifying facilities receive capacity payments, but the small size of the system means that the retirement of a single large generator will have significant impact on the reserve margin, and hence system reliability.

All else being equal, a market with larger share of renewable intermittent such as wind and solar will likely see a greater portion of generator revenue made up of capacity payments than in markets dominated by thermal generation, as spot energy prices decrease to reflect the lower marginal operating cost of renewable generation.

4.5 The WEM demand curve is shallower than other jurisdictions

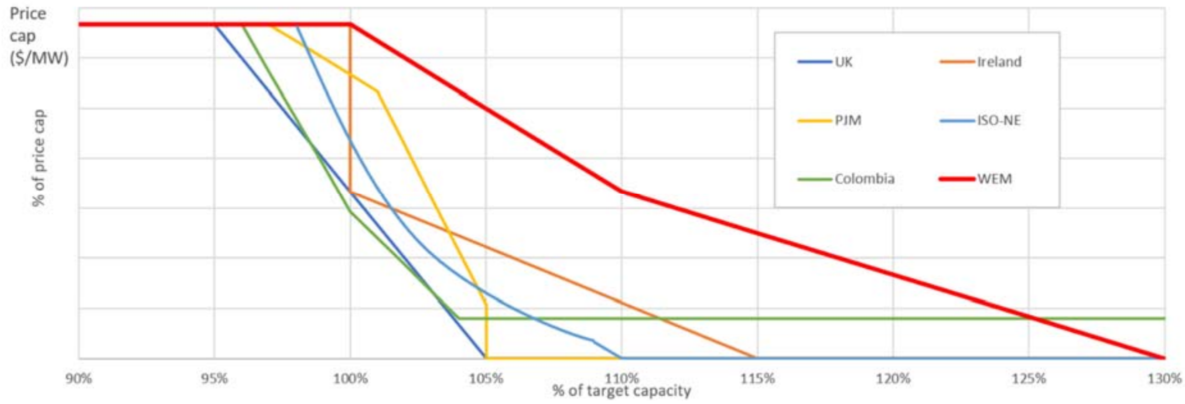
The method of setting the BRCP is explicitly in scope of the RCM Review project. The remainder of the pricing regime is out of scope, including the demand curve, the fixed price option, and the refund regime.

This international review provides an opportunity to compare the WEM price settings to other markets, and we note that the WEM demand curve is a relative outlier compared to the jurisdictions reviewed.[43]

In the markets studied (other than France, with its decentralised regime), the auction operator determines a demand curve for inclusion in the auction. A near vertical demand curve is susceptible to significant price volatility (where the price flips quickly from the price cap to zero). It also provides greater opportunity for participants to manipulate the market by withholding capacity. The demand curve in WA is therefore sloped to avoid these issues. Figure 20 shows the various demand curves.

[43] Noting that the WEM price applies to all facilities, while other jurisdictions only pay the auction winners.

Figure 20: Demand curves in selected capacity mechanisms



In the WEM, the demand curve relates to all capacity in the market, not just a subset participating in the auction. The WEM price curve is significantly shallower than other markets. For example, in Ireland, the capacity market price reaches zero when the capacity reaches 115% of the target capacity level while in the RCM, the capacity price reaches zero only when the level of capacity is 30% more than the target capacity.

In the WEM, the price cap applies at 100% of the target, and the price reduces from there. Most of the other markets have a demand curve which allows price increases when supply is less than the capacity target.

All markets use a benchmark value to calibrate the demand curve, based on the CONE for a specific new entrant resource. Table 3 shows how the price caps and floors are calculated, along with the resource used to set the benchmark.

Table 3: Price benchmark references in studied markets

Jurisdiction	Price cap	Price floor	Determination of CONE
PJM	$\frac{\text{Max (CONE,1.5 x net-CONE)}}{1-\text{Poolwide Equivalent Forced Outage Rate}}$ at 97%	0 at 105%	CT using GE Frame 7HA turbine
ISO-NE	$\frac{\text{Max (CONE,1.6 x net-CONE)}}{1-\text{Poolwide Equivalent Forced Outage Rate}}$ at 98%	• 0 at 110%	Gas-fired simple-cycle combustion turbine
Colombia	2x CONE at 96%	½ CONE at 104%	New efficient peaking unit
UK	1.5x Net CONE at 95%	0 at 105%	New CCGT

Ireland	1.5x CONE at 100%	0 at 115%	CCGT using GE9FB.05 turbine
WEM	1.5x BRCP	0 at 130%	60MW OCGT

The CONE is the capital investment costs for the facility, plus the operational and maintenance expenses for the first year of operation.

Net CONE is the CONE less an estimate of the contribution of energy and ancillary services revenues towards capital costs. These are the inframarginal rents, or profits from supplying market services at a profit. This measure assumes that the marginal new entrant would receive some contribution to capital costs from the energy market.

The international review shows no consensus on whether CONE or Net CONE is a more appropriate benchmark, but all use gas fired generation as the new entrant technology. The appropriate measure and assumed marginal new entrant technology for the WEM will be considered later in the project.

4.6 OTHER MARKET DESIGN FEATURES

In addition to the five issues above, we noted a variety of other design features that differ from the WEM approach. This section describes them and discusses potentially applicability in the WEM.

4.6.1 Capacity mechanism opt out

PJM's Fixed Resource Requirement (FRR) allows vertically integrated entities to opt out of the capacity market. These entities must prove that the generation they control is sufficient to meet their expected load, and that generation must not be offered in the auction. Their actual performance is checked, and they face extremely high penalties for non-performance.

The WEM's intermittent load scheme has some similarities, but the need to fund capacity credits over and above the reserve capacity requirement means that the full PJM approach is not appropriate for the WEM.

4.6.2 Resource adequacy standard

France's decentralised regime requires retailers to forecast their own estimated peak load rather than having a central party allocate requirements to each participant. This option is also under consideration in the NEM.

This approach could be considered for the WEM, but its applicability to multiple types of system stress would require a more complex arrangement than the simple focus on peak load used in France and contemplated for the NEM.

4.6.3 Dedicated procurement volumes to encourage specific types of supply

Some markets studied procure capacity in multiple locations, meaning there are effectively multiple capacity products. None go so far as to define specific capacity products for different technologies, and those that provide financial advantages to specific technology types do so via separate schemes to subsidise entry of renewable or storage technologies.

The WEM currently has no state-specific renewable subsidy schemes, though renewable generators are eligible for federal renewable energy certificates.

This suggests that any financial support for renewables should be outside the RCM.

4.6.4 Temperature dependence

The WEM RCM uses temperature derating to assess facility capacity at 41 degrees Celsius. Some markets studied also consider temperature dependence at low temperatures, particularly where peak demand occurs in winter and is correlated with temperatures below freezing. Some technologies suffer significant performance deterioration when ambient temperatures drop a long way below freezing, as evidenced in Texas in early 2021, when gas fired generation was unable to operate due to frozen fuel supply infrastructure.

This issue is not likely to be relevant in the WEM, even as winter demand increases relative to summer demand.

4.6.5 Length of guarantees for new build

Some markets studied provide more than one year of revenue guarantee for new facilities:

- PJM provides a three-year guarantee;
- ISO-NE had a seven-year guarantee, but reduced to five years after FERC rejected seven as too long;
- France’s renewable underwriting scheme (separate to the decentralised capacity mechanism) provides seven-year contracts;
- Colombia provides up to 20 years;
- In the UK, new entrant generators are eligible to be awarded contracts for up to 15 years; and
- In Ireland, new-build facilities are offered up to 10-year contracts.

The WEM's option for facilities to seek a five-year fixed capacity price has not yet been exercised. The current capacity surplus means that there is sufficient capacity prepared to accept a price that changes from year to year, so that the additional guarantee has not been needed to encourage new supply.

This aspect of design is out of scope of the current review.

4.6.6 Obligation timing

The WEM RCM requires facilities to make their accredited capacity available:

- For conventional facilities, at all hours of the year, except when on planned outage;
- For storage facilities, during specific peak hours each day; and
- For demand side response, during weekday daytime hours (8am to 8pm).

Intermittent resources are not directly penalised for non-production, as they are assumed to always produce at the maximum possible. A non-producing intermittent resource would likely see a reduction in certified capacity the following capacity year under the current RLM.

In contrast to the WEM's 'all hours' model:

- France requires capacity to be provided only on day-ahead notice by the System Operator; and
- Colombia and Ireland structure their capacity product as a reliability option effectively requiring providers to operate when the spot energy price rises above a specified level.

The former would significantly dilute the capacity assurance provided by current WEM settings, while the latter would be a fundamental change in the way the WEM capacity product operates.

4.6.7 Penalty payments distribution

When capacity providers fail to meet their capacity obligations, most markets subject them to penalties or require a refund of capacity payments. In the WEM, these payments are distributed to other holders of capacity credits based on the number of credits they hold.

In PJM, these payments are distributed to owners of facilities that *over* performed by providing more than their obligated quantity during that interval, and therefore made up for the missing capacity.

This approach could be considered in the WEM to further incentivise parties to be available and mitigate the risk of non-performance.

Appendix A Overview of the WEM

MARKET INFORMATION	
Energy Market	
Gross vs Net pool	Gross pool
Trading interval	30 minutes
Locational pricing	No
Day ahead market	Yes
Real time market	Yes
Interties	No
Capacity mechanism	
Procurement structure	Reserve Capacity Mechanism with decentralized capacity obligation
Additional features	Additional Capacity is procured via direct contracts if capacity is insufficient
Auction type	No auction
Resource adequacy requirement	Peak demand based on 1-in-10-year peak. Greater of (i) Local requirements based on forecast peak demand plus a reserve margin of 7.6% or capacity of the largest generator or (ii) expected shortfall less than 0.002% of annual energy consumption
Timeline	3 years ahead of delivery
Price information	Capacity price is set by an administrative methodology, with a benchmark capacity price based on the capital costs of a new build OCGT.
Intermittent in capacity mechanism	Can participate in capacity mechanism in addition to receiving Large Generation Certificates.

A.1 Market Structure

Western Australia's WEM started operations in 2006, with capacity mechanism activity for that year beginning in 2004. The WEM operates in the SWIS, which is centred on Perth, stretching north to Kalbarri, south to Albany, and east to Kalgoorlie. The SWIS is an isolated power system and is not connected to either the NEM on Australia's east coast, or the North West Interconnected System in northern Western Australia.

AEMO operates the WEM, and dispatches facilities based on supply and demand conditions. Development and oversight are the responsibility of the Coordinator of Energy, EPWA, and the ERA. Transmission and distribution networks in the SWIS are owned and operated by Western Power (a state-owned entity), which is also the meter data agent for the SWIS. State owned Synergy is the largest generator and retailer.

The WEM consists of the following arrangements for trading electricity:

- RCM;
- STEM;
- Balancing Market;
- Load Following Ancillary Service Market[44].

The purpose of the WEM RCM is to procure sufficient capacity to meet expected demand in the summer peak period. The RCM runs on a three-year cycle, assigning credits to all eligible facilities at an administered price. If there is a shortfall in capacity, supplementary capacity can be procured via direct contracts. The RCM is covered in more detail in section A.2.

The STEM is a day-ahead market which can be used by the market participants to trade around their bilateral contract position.

The gross pool Balancing Market matches real-time supply and demand. The Balancing Market operates as a simple merit order with no consideration of network constraints[45].

Load Following Ancillary Services are procured through a separate market, cleared ahead of energy. All other essential system services are procured through direct contracts.

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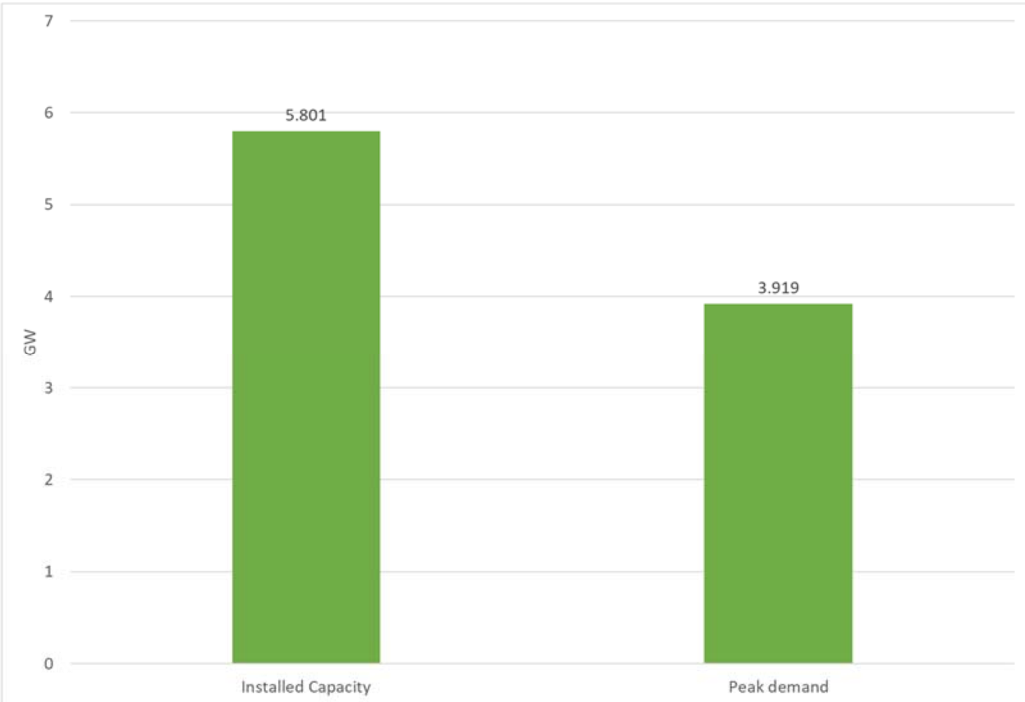
[44] In 2023, the Balancing and LFAS markets will be replaced with a single co-optimised Real-Time Market.

[45] The new Real-Time Market will account for more system parameters, optimising to clear supply and demand at least cost while respecting network constraints, facility capabilities and essential system service requirements.

In 2019, the summer peak operational demand[46] reached 3.9 GW (the second highest recorded peak demand since the energy market started operating in 2006), on a total installed capacity of 5.8 GW.

Grid-connected electricity generation is dominated by gas and coal-fired power plants. In 2020, wind contributed 15% of total generation while grid-scale solar contributed a little over 1%. However, the largest source of energy is now distributed solar photovoltaics (DPV), mostly on residential roofs, which reached a capacity of 1.3 GW in February 2020[47]. According to 2020 WEM Electricity Statement of Opportunities (ESOO), the increasing DPV installations continue to drive down the operational peak load, and according to the report, for the first time from 2020-2021 capacity year, the forecast 10% Probability of Exceedance (POE)[48] peak demand is expected to be lower than the prior year.

Figure 21: SWIS 2019 Installed Capacity vs Peak Demand

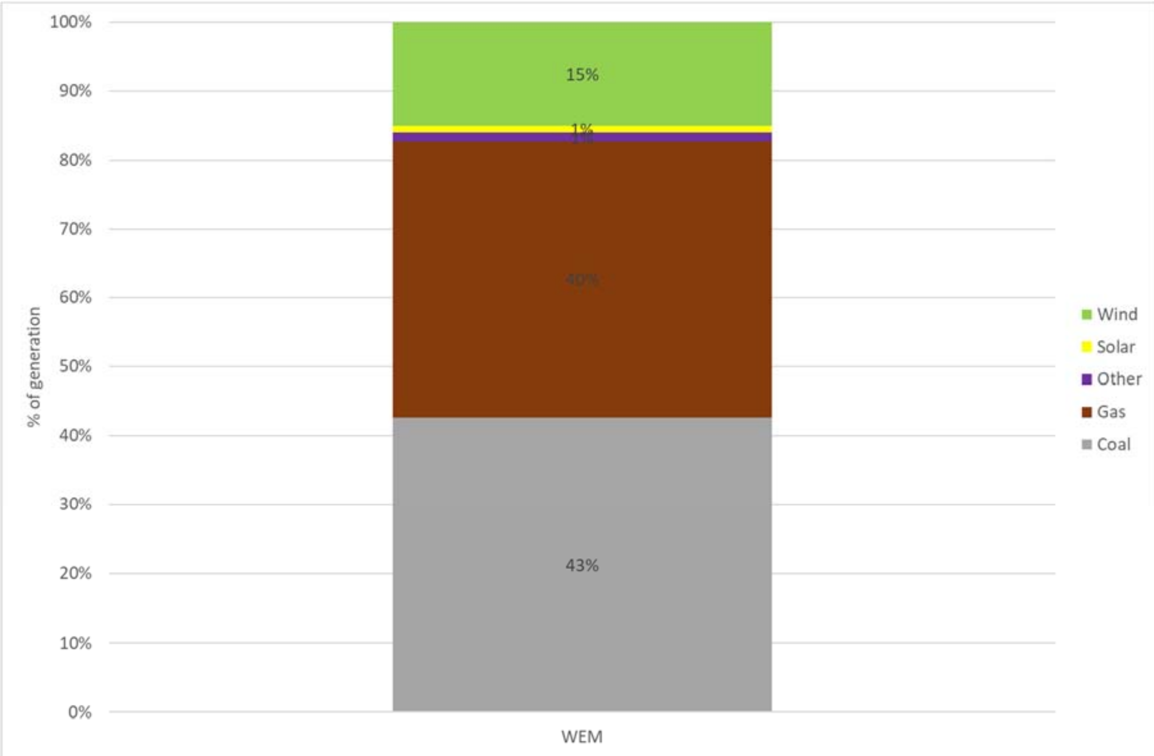


[46] Demand observed after the effects of behind-the-meter generation such as residential solar PV.

[47] Western Australia's dramatically changing electricity consumption

[48] POE is the probability that a peak demand forecast will be exceeded. A 10% POE peak demand forecast is expected to be exceeded, on average, only one year in 10

Figure 22: SWIS – 2020 Generation mix



A.2 Capacity mechanism arrangement

The WEM RCM is a quantity-based, market-wide mechanism for procuring capacity to ensure resource adequacy during system stress events.

A.2.1 Reliability criterion

The RCM planning criterion has two limbs. The RCM must procure sufficient capacity to:

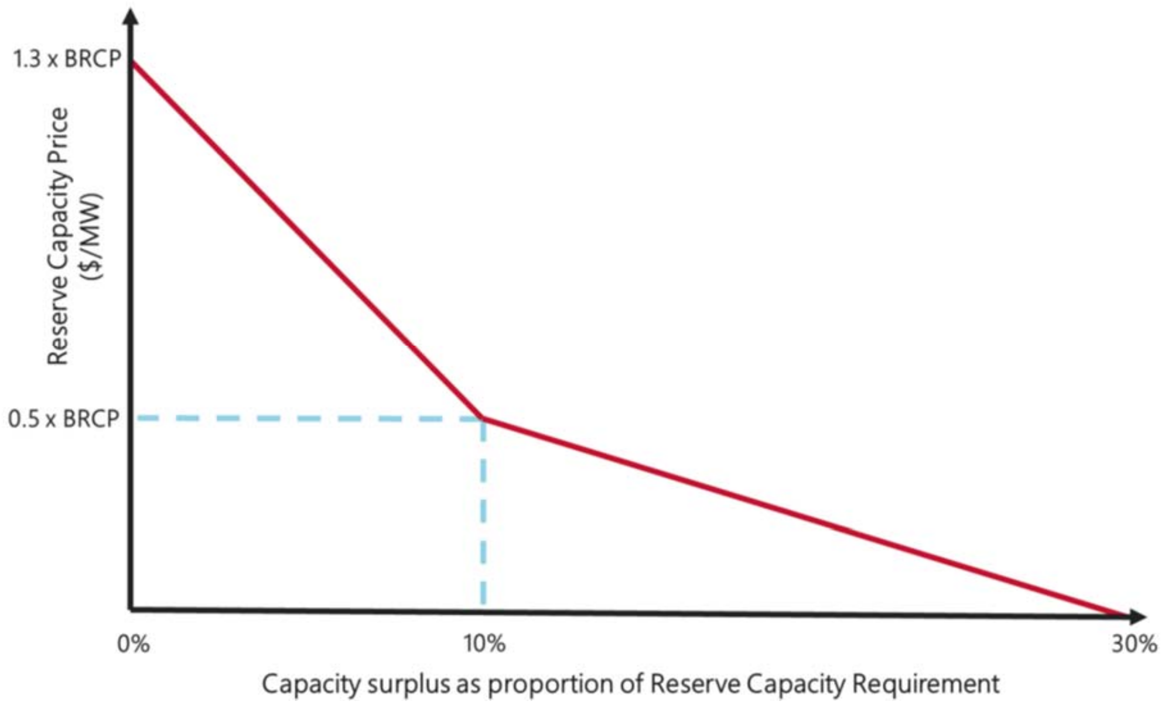
- Meet the forecast one-in-10-year POE peak demand plus a margin of 7.6% or the capacity of the largest generator while maintaining system frequency or
- Ensure that energy shortfalls do not exceed 0.002% of total load for the capacity year including transmission losses and constraints.

Historically, the second criterion of 0.002% of unserved energy has never bound, and the capacity target has been set by the first limb in all years.

A.2.2 Pricing

There is no capacity auction. All parties holding capacity credits are eligible to be paid the Reserve Capacity Price, which is an administered price set on a curve based around the BRCP as shown in Figure 23. The BRCP is set to reflect the cost of entry of a new 160 MW OCGT generation facility.

Figure 23: Reserve Capacity Price curve (WEM Reform: Wholesale Electricity Market Design Summary)



The price received by a Variable Price Facility changes from year to year, as the BRCP and supply/demand balance changes. New facilities seeking price certainty can opt to nominate themselves as Fixed Price Facilities. If accepted, they will be guaranteed to receive the same (CPI adjusted) Reserve Capacity Price for five years. Fixed Price Facilities will only be awarded capacity if there are insufficient Variable Price Facilities to meet the reserve capacity target.

If six months prior to the capacity year AEMO considers that there is not enough capacity to meet the reliability target, it can directly contract for Supplementary Reserve Capacity, the use of which is not governed by the WEM Rules, rather by the contract terms.

A.2.3 Network access

The WEM currently historically operated on an unconstrained basis. Every facility which connected could expect to be able to inject or withdraw its full capability at any time. A connecting facility was liable to pay 'deep connection costs' to cover network upgrades if the network could not accommodate its full capacity.

A newly revised constrained network access model now allows new entrants to connect to the SWIS without funding deep network augmentation and as a result there will be no guaranteed level of access for participants to the network in real-time dispatch, with AEMO selecting the most cost-effective combination of facilities to meet demand in any given dispatch interval. This change exposes incumbent generators to the risk of new entrants locating in a congested area of the network and therefore displacing existing capacity.

From the 2022 capacity cycle, AEMO will allocate network access rights to existing generators in the form of Network Access Quantities (NAQ) and will consider NAQs when assigning capacity credits to facilities. This means that if a new facility builds in an already congested area where it does not add marginal value to system reliability, it will not receive capacity credits.

Facility developers can still contribute to network augmentation, and those which do are prioritized for NAQ over new facilities or upgrades to existing facilities.

A.2.4 Determining Capacity Contributions

There is no restriction on technology participation in the RCM. Generators, storage, and demand response options can all be allocated capacity credits. Participating resources are categorized into two classes:

- Availability Class 1 – All generators (including hybrid resources with storage) which can provide capacity at all hours during the year.
- Availability Class 2 – Standalone storage resources and demand side programmes, which have availability or storage restrictions.

AEMO determines the level of Certified Reserve Capacity for each facility based on its ability to provide capacity during periods of system stress. Different facilities are awarded capacity based on various technical requirements:

- Non-intermittent generators are awarded based on sent-out capacity at 41°C.
- Intermittent generators are awarded capacity based on the Relevant Level Methodology (RLM), which considers historical generation output at times of highest non-intermittent generation.

$$RL = Average\ Facility\ Output\ during\ peak\ Trading\ Interval - \left(\left(K + \frac{U}{Average\ Output}\right) \times Variance\ of\ facility\ output\ during\ peak\ Trading\ Interval\right)$$

  Where RL is the Relevant Level of the intermittent generator in MW,
  $K = 0$ based on the probability distribution of demand and available capacity of existing resources and their correlation.
  $U = 0.635$ is the ratio of the change in load for scheduled generation, on peak

demand days when air temperature was above 38°C to the mean output of fleet of intermittent generators during peak demand trading interval[49]

- Electricity storage resources are awarded based on their ability to sustain output for eight consecutive Trading Intervals (four hours), accounting for both instantaneous energy injection capability and storage volume.
- Demand side programmes are awarded capacity based on the quantity of load they can curtail relative to their demand in peak intervals.
- Hybrid facilities are awarded capacity for each component separately.

AEMO awards capacity credits based on CRC and NAQ.

Non-intermittent facilities holding capacity credits are obliged to always make capacity available in the STEM and the Balancing Market (except when on planned outage) and are liable for refunds when they fail to do so. Intermittent generators are assumed to always produce as much as possible and are subject to refunds only when undergoing a forced outage. DSPs are only subject to refunds if they do not perform when called upon.

A.2.5 Trading and cost recovery

AEMO calculates an Individual Reserve Capacity Requirement (IRCR) for each party purchasing energy from the WEM based on its contribution to the overall demand. Participants are required to acquire capacity credits to cover their IRCR. Participants can trade capacity credits bilaterally and notify AEMO of their trades for settlement purposes. Any credits not traded bilaterally are acquired by AEMO, which allocates the cost first to participants who have not covered their IRCR, and then recovers the remaining costs from all IRCR holders based on their total consumption

[49] Values were determined by Sapere Research Group.

Appendix B MARKET COMPARISON

B.1 Summary table – All Jurisdictions

MARKET INFORMATION							
Jurisdiction	**PJM**	**ISO-NE**	**France**	**Colombia**	**United Kingdom**	**Ireland**	**WEM**
Energy Market							
Gross vs Net pool	Gross pool	Gross pool	Net pool	Gross pool	Net pool	Gross pool	Gross pool
Trading interval	5 minutes	5 minutes	30 minutes	1 hour	30 minutes	30 minutes	30 minutes
Locational pricing	Yes	Yes	No	No	No	No	No
Day ahead market	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Real time market	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Interties	Yes	Yes	Yes	Yes	Yes	Yes	No

MARKET INFORMATION							
Jurisdiction	**PJM**	**ISO-NE**	**France**	**Colombia**	**United Kingdom**	**Ireland**	**WEM**
Capacity Mechanism							
Procurement structure	Reliability Pricing Model	Forward Capacity Auctions	Decentralized capacity procurement	Firm energy obligation auction	Capacity market with auctions	Capacity Remuneration Mechanism – Reliability Options	Reserve Capacity Mechanism with decentralized capacity obligation
Additional features	Bilateral trading	Bilateral trading	Optional participation with obligation	Call option and bilateral trading through a reliability mechanism	Bilateral trading	Bilateral trading with reliability options	Additional Capacity is procured via direct contracts if capacity is insufficient
Auction type	Mandatory centralized uniform price auction	Mandatory centralized descending clock auction	Optional auction	Centralized descending clock auction	Voluntary centralized descending clock auction	Central buyer uniform price sealed bid auction with locational network constraints	No auction

MARKET INFORMATION							
Jurisdiction	**PJM**	**ISO-NE**	**France**	**Colombia**	**United Kingdom**	**Ireland**	**WEM**
Resource adequacy requirement	System wide and local requirements set by 0.1 LOLE study (i.e.) 1 event in 10 years	System wide and local requirements set by 0.1 LOLE study	Local requirements based on LOLE which is 3 hours per year	Local requirements set by CONE and LOLE	Local requirements based on LOLE which is 3 hours per year	Local requirements based on LOLE which is 8 hours for Ireland and 4.9 hours for Northern Ireland	Peak demand based on 1-in-10-year peak. Greater of (i) Local requirements based on forecast peak demand plus a reserve margin of 7.6% or capacity of the largest generator or (ii) expected shortfall less than 0.002% of annual energy consumption

MARKET INFORMATION							
Jurisdiction	**PJM**	**ISO-NE**	**France**	**Colombia**	**United Kingdom**	**Ireland**	**WEM**
Timeline	3 years in advance. Incremental auctions are held up to the delivery year.	3 years in advance. Incremental auctions are held annually and monthly	Market operates on a continuous basis until delivery. Trades can take place in OTC or organized exchanges	3 years in advance. but this will increase by six months in each successive auction, until it reaches 4 years	There is a four-year-ahead auction followed by a year-ahead auction	There is a four-year-ahead auction followed by a year-ahead auction	3 years ahead of delivery
Price information	Sloped demand curve is used based on the system capacity requirement, the net-CONE, and demand reservation prices.	Sloped demand curve is used based on LOLE and net-CONE	Certificates are traded with a price cap of €60 000/MW (2020)	Sloped demand curve with firm energy price having a ceiling of two times CONE and a floor of one-half times CONE.	Sloped demand curve with a price cap of GBP 75,000/MW (2014). 95% target capacity at price cap and 105% target capacity	Sloped demand curve with price cap at 150% of CONE. 100% of target capacity at price cap, then target capacity at 100% CONE and finally zero	Capacity price is set by an administrative methodology, with a benchmark capacity price based on the capital costs of a new build OCGT.

MARKET INFORMATION							
Jurisdiction	**PJM**	**ISO-NE**	**France**	**Colombia**	**United Kingdom**	**Ireland**	**WEM**
					where price reaches zero	price at 115% target capacity	
Intermittent in capacity mechanism	Can receive RE support from state as well as partake in capacity market	Can receive RE support from state as well as partake in capacity market	Diminishes RE revenue when participating in the capacity mechanism	Tenders occur in parallel but do not overlap	Prohibits RE support when participating in the capacity market	Diminishes RE revenue when participating in the capacity mechanism	Can participate in capacity mechanism in addition to receiving Large Generation Certificates.

B.2 Generation Mix by Jurisdiction