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Energy Markets Policy
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Discussion Document: Accelerating renewable energy and energy efficiency

Meridian appreciates the opportunity to make a submission on the Ministry of Business, Innovation and Employment (**MBIE**) discussion document *Accelerating renewable energy and energy efficiency*.

All the energy that Meridian generates comes from 100 percent renewable sources – wind, water and sun. We're New Zealand's largest generator, making power through our wind farms, hydro stations and solar arrays. Meridian is committed to meeting current and future energy needs with renewable energy and taking action on climate change.

As a renewable generator, Meridian in this submission is focused on:

- Section 7: Enabling development of renewable electricity generation under the Resource Management Act 1991 (**RMA**); and
- Section 8: Supporting renewable electricity generation investment.

Meridian has for a long time supported several of the options in the discussion document, particularly those in section 7 that would strengthen national direction under the RMA to:

- remove barriers and unnecessary costs in respect of new renewable generation developments; and
- simplify the reconsenting of existing renewable generation.

Meridian advocated for these options throughout the consultation processes for the Productivity Commission's *Low-emissions economy* report and the Interim Climate

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Change Committee's (**ICCC**) *Accelerated electrification* report. Meridian supports the conclusions that both agencies reached, and we are now pleased to see that revising the National Policy Statement for Renewable Electricity Generation (**NPSREG**) is a priority of the Government's work programme.

In considering the options in the discussion document it is important to keep sight of the problem that the options seek to address. Meridian considers the fundamental objective to be the reduction of greenhouse gas emissions across the economy to:

- meet the 2050 emissions target in the Climate Change Response Act 2002;
- in the short-term, meet the proposed interim emissions budget to 2025; and ultimately
- contribute to the global effort under the Paris Agreement to limit the global average temperature increase to 1.5° Celsius above preindustrial levels.

The discussion document seems to identify a secondary, "aspirational" goal of 100 percent renewable electricity generation by 2035 as an objective in and of itself. An aspiration has no effect on its own, however, active policy interventions that flow from that aspiration can have effects that are inconsistent with the emissions objectives noted above. Renewable generation is one of many moving and interlinked pieces of the New Zealand economy and interventions that raise electricity prices in order to accelerate investment in renewable generation are likely to result in worse emissions outcomes because of the reduced incentives to electrify transport and industrial process heat. Any increase in electricity prices to support investment in renewable generation would also run counter to the recommendations of the Electricity Price Review, which seek lower electricity prices for consumers. It is worth reiterating the ICCC recommendation that the Government:[1]

> "Prioritises the accelerated electrification of transport and process heat over pursuing 100% renewable electricity by 2035 in a normal hydrological year because this could result in greater greenhouse gas emissions savings while keeping electricity prices affordable."

Meridian also strongly agrees with the Productivity Commission's key recommendations that:[2]

> "Given rapid changes in electricity-generation technology and potential effects of rising electricity prices on adoption of low-emissions technology in other parts of the

[1] ICCC *Accelerated electrification* p98.
[2] Productivity Commission *Low-emissions economy* p537.

economy, the Government should not use subsidies or regulation to favour particular technologies that generate low-emissions electricity."

"The Government should rely on an effective emissions-pricing system as the main instrument to achieve an efficient trade-off between emissions reductions in electricity and emissions reductions in other parts of the economy. The Government should be cautious in specifying targets for emissions within the electricity sector, and make sure that technology is available to meet them without significantly increasing wholesale electricity prices above the levels achieved with current technology."

Many of the options in section 8, and elsewhere in the discussion document appear to involve direct intervention in markets in an attempt to speed the uptake of renewable generation at the expense of consumers or taxpayers. Not only do these options risk worse emissions outcomes, they are also unnecessary. Modelling by MBIE, the ICCC, Meridian and others consistently shows that even under business as usual scenarios, renewable generation will increase to between 90 and 97 percent market share by around 2035.[3] Renewable options are already the most economic form of electricity generation and uptake will therefore occur at an efficient rate without any changes to the market. In the longer term, improvements in technology and new technology developments, lower costs for renewable generation developments, and improvements to demand response are likely to mean that any remaining thermal generation can also be removed from the New Zealand electricity system without raising prices. Meridian considers the current market alongside a reformed New Zealand Emissions Trading Scheme (**ETS**) capable of achieving this long-term outcome while also achieving the ultimate objective of reducing emissions at least cost.

If the Government wants to achieve more rapid reductions in emissions or more rapid uptake of renewable generation, there are tools available to efficiently achieve this outcome. Meridian considers the ETS to be the centrepiece of New Zealand's emissions reduction efforts. The ETS and proposed reforms currently before Parliament have been designed so that emissions volumes can be restricted over time by the Government and if the Government wants to move faster it can. Annual restrictions on the volume of emissions units will increasingly drive higher market prices for the units available and more emissions mitigation to avoid ETS liabilities. In the words of the Productivity Commission:

[3] For example, MBIE *Electricity demand and generation scenarios* p29; ICCC *Accelerated electrification* p47; Meridian *Wholesale market outlook 2020* extract in Figure 2 below.

> “Emissions pricing is a powerful policy instrument to reduce emissions. Emissions pricing provides strong incentives to reduce emissions at least cost. It decentralises decisions to invest, innovate and consume across the economy to people who have the best information about opportunities to lower emissions given their circumstances. An emissions price is also pervasive through the whole economy – shaping resource and investment decisions across all emitting sectors and sources.”

The discussion document states that the options in the paper are intended to be complementary to the ETS. Many are complementary; however, some options would regulate to pick winners amongst different technology options or create additional financial incentives to avoid emissions. These options would therefore be duplicative of the incentives under the ETS and/or distort the market for emissions units, in general by targeting specific activities to bear the cost of emissions reductions and simultaneously supressing emissions prices across the rest of the economy. Rather than add further regulation and risk market distortions, Meridian recommends that the Government implement the ETS reform proposals currently before Parliament and monitor the impact of the resulting higher emissions prices. Over time the Government will need to be increasingly willing to accept higher market prices for emissions units and be prepared to make decisions to restrict unit volumes and lift the cost containment reserve price in the ETS.

Like the Productivity Commission[4], Meridian accepts there are exceptions to the principled, ETS-centric approach and that there is a case for prioritising complementary policies where those policies are targeted to avoid investments that lock in emissions for an extended period, for example:

- recent Ministry of Transport proposals to introduce emissions standards for vehicle imports and a feebate scheme to accelerate the uptake of low-emission vehicles; and
- limits on the installation of new fossil-fuel powered heating systems (as per option 4.1 in the current discussion document).

The discussion document states that, “We seek your feedback on both the *sequencing* and the *optimal package* of policies outlined in the document”. To that end, the table below indicates in summary the options that Meridian supports as a priority (in green),

[4] Productivity Commission *Low-emissions economy* p506.

options that Meridian does not support (in red) and the remaining options (unmarked) where Meridian does not have a strong opinion or has a more nuanced opinion.

Section 1: Addressing Information Failures	
Require large energy users to publish Corporate Energy Transition Plans (including reporting emissions) and conduct energy audits.	
Develop an electrification information package for businesses looking to electrify process heat, and offer co-funded low-emissions heating feasibility studies for EECA's Large Energy User partners.	
Provide benchmarking information for food processing industries.	
Section 2: Developing markets for bioenergy and direct geothermal use	
Development of a users' guide on the application of the National Environmental Standards for Air Quality to wood energy.	
Section 3: Innovating and building capability	
Expand EECA's grants for technology diffusion and capability-building.	
Collaborate with EIHI industry to foster knowledge sharing, develop sectoral low-carbon roadmaps and build capability for the future using a Just Transitions approach.	
Section 4: Phasing out fossil fuels in process heat	
Introduce a ban on new coal-fired boilers for low and medium temperature requirements	
Require existing coal-fired process heat equipment supplying end-use temperature requirements below 100°C to be phased out by 2030.	
Section 5: Boosting investment in energy efficiency and renewable energy technologies	
No new options are proposed at this time.	
Section 6: Cost recovery mechanisms	
Introduce a levy on consumers of coal to fund process heat activities.	
Section 7: Enabling development of renewable electricity generation under the RMA	
Amend the NPSREG to provide stronger direction on the national importance of renewables	
Scope National Environmental Standards or National Planning Standards specific to renewable energy	
Other options	
Section 8: Supporting renewable electricity generation investment	
Introduce a Power Purchase Agreement (PPA) Platform	
Encourage greater demand-side participation and develop the demand response market	
Deploy energy efficiency resources via retailer/distributer obligations	
Develop offshore wind assets	
Introduce renewable electricity certification and portfolio standards	
Phase down thermal baseload and place in strategic reserve	
Other options	
Section 9: Local and community energy engagement	
Ensuring a clear and consistent government position on community energy issues, aligned across different policies and work programmes	
Government supports development of a small number of community energy pilot projects, through options including financial support, 'handholding' and facilitating of projects, or assisting with regulatory approvals and access to land	
Section 10: Connecting to the national grid	
Encourage Transpower to include the economic benefits of climate change mitigation in applications for Commerce Commission approval of projects expected to cost over $20m	
Put in place additional mechanisms for, or encourage, Transpower, first movers and subsequent customers to agree to alternative forms of cost sharing arrangements by contract	
Shift some of the cost and risk allocation for new and upgraded connections from the first mover through mechanisms within the Commerce Commission's regulatory scope, with the Crown accepting some of the financial risk.	
Provide independent geospatial data on potential generation and electrification sites (e.g. wind speeds for sites, information on relative economics and feasibility of investment locations given available transmission capacity)	
Extend the data and information provided in MBIE's EDGS and increase the frequency of publication, and potentially recover the cost through the existing levy on electricity industry participants.	
Produce a user's guide on the current regulations and approval processes relating to getting an upgraded or new connections to the grid	
Provide a "map" or database of potential renewable generation and demand sources, location and potential size (e.g. wind, geothermal, milk plant).	
Introduce measures to enable coordination regarding the placement of wind farms to ensure they are more likely to be better distributed around the country	
Section 11: Local network connections and trading arrangements	
No new options are proposed at this time.	

The remainder of this submission highlights Meridian's key comments under each of the section headings from the discussion document. Responses to the detailed consultation questions are appended at the end of this submission.

Section 1: Addressing Information Failures

Meridian supports a requirement for large energy users to publish Corporate Energy Transition Plans (including reporting emissions annually) and to conduct regular energy audits. Ideally these plans would be linked to investments in energy efficiency or clean energy – discussed further in Section 5 below. Meridian considers the costs of such regulation to be justified in respect of large businesses. While some individual businesses may be concerned about the increased transparency, Meridian considers climate related disclosures to be best practice corporate governance for all large businesses. Disclosure would help to build trust and enable market analysts, researchers, investors and the Government to form a more complete picture of New Zealand's greenhouse gas emissions and energy transition. This option would be consistent with other climate related transparency measures that have recently been implemented or proposed, for example:

- the Climate Change Response (Emissions Trading Reform) Amendment Bill currently before Parliament includes a new section 89A that would require the Environmental Protection Authority (**EPA**) to publish participant data on net emissions and removals by activity and by period;
- in December 2019, the Ministry for the Environment and MBIE consulted on proposed legislation for mandatory climate-related financial disclosures;
- in 2019 large sections of the business community through the Climate Leaders Coalition committed to voluntarily assessing and disclosing climate change risks;[5]
- in early 2019, the Reserve Bank contacted registered banks and licensed insurers requesting information about how they identify, manage and disclose climate risk;
- the NZX has issued a guidance note relating to environmental, social and governance reporting; and
- under existing section 5ZW of the Climate Change Response Act the Minister or the Commission may require a range of organisations to report on climate change risks and how those organisations identify, assess, and manage those risks.

The coverage of these climate related disclosures is broad and there are many overlaps between the types of information to be provided. Meridian encourages government

[5] https://www.climateleaderscoalition.org.nz/about/2019-statement.

departments to work together to understand and rationalise the range of climate related information disclosure obligations and to whom they apply. There will be opportunities to standardise reporting methodologies and align timing, thus reducing compliance costs for businesses.

In general, Meridian also supports the development and provisions of information resources by the Government. The provision of information can help to overcome barriers, is low cost, and does not risk unintended consequences or market distortions. We therefore support the options to:

- develop an electrification information package for businesses looking to electrify process heat, and offer co-funded electrification feasibility studies for EECA's business partners; and
- provide benchmarking information for food processing industries.

Section 2: Developing markets for bioenergy and direct geothermal use

Meridian does not have expertise in markets for bioenergy or direct geothermal use. However, we consider the option to develop a users' guide on application of the National Environmental Standards for Air Quality to wood energy another example of a low risk, low cost option for the provision of information by Government. Meridian supports such options to the extent that an audience and need for the information is identified.

It is unclear to Meridian how the Government would facilitate development of bioenergy markets or support direct geothermal use. Meridian questions whether the Government had greater knowledge and expertise than the industry and can achieve anything more than what contracting between industry participants might deliver. Investments in bioenergy and direct geothermal use need to be made by businesses and must be economic for the life of an investment. If a project looks viable then it seems likely that businesses will invest in studies to prove the business case, regardless of what role the Government decides to play in this space.

Any direct Crown investment in wood processing should only proceed where the Crown sees a viable business case that would deliver returns for tax payers. If the Crown invests directly in uneconomic developments there will not only be a cost to taxpayers but a crowding out of private investment.

Section 3: Innovating and building capability

Meridian tentatively supports the option to expand EECA's grants for technology diffusion and capability-building. However, we note that funding for these grants is currently derived in part from the electricity levy[6] and therefore an increase in funding would increase electricity prices for end consumers. This, on top of other levy funded options from the Electricity Price Review could see a significant increase in the levy over the next few years. We suggest this potential should be avoided.

Regarding the option to collaborate with emissions-intensive and highly integrated industries to foster knowledge sharing, develop sectoral low-carbon roadmaps and build capability for the future – it is not clear what benefits such studies and strategies will deliver and what expertise Government would bring to such collaboration. Any investment in energy efficiency or renewable energy would need to be based on a sound business case and individual businesses are best placed to understand the costs and benefits of potential energy investments. With the right financial incentives, businesses will do this without any support from Government. Meridian therefore considers the role of Government to be to create financial incentives for businesses to make economic decisions that are both in their own interest and deliver emission reduction. The ETS, by altering the relative costs of different fuels and the benefits of efficiency improvements is the primary tool to deliver the outcomes sought and can do so without costly, hands-on, collaborative studies into what businesses 'should' be doing in the opinion of the Government.

Section 4: Phasing out fossil fuels in process heat

Meridian supports the option to ban new coal-fired process heat equipment for low and medium temperature requirements. While a ban does pick winners and may suppress emissions prices under the ETS, reducing abatement in other areas, this option would ensure New Zealand avoids locking in new long-lived and emissions intensive coal boilers. This is the sort of policy intervention recommended by the Productivity Commission as a priority to complement the ETS.[7] Meridian agrees that a ban would be simple to administer, involve minimal costs to Government, and could be introduced quickly. The Government would need to consider the scope of any ban and whether to target only new

[6] In 2019/20 EECA's funding from the electricity levy totaled $5.2 million.
[7] Productivity Commission *Low-emissions economy* p506.

industrial process heat coal users or to also look more broadly at other new investments in coal boilers, for example to heat large buildings, schools, or hospitals (many of which are Crown owned).

While a ban on new investments might be justifiable, the position is less clear for the option to phase out by 2030 *existing* coal-fired process heat equipment supplying end-use temperature requirements below 100°C. In this case investments have been made in the assets already with a reasonable expectation of being able to use those assets. Investors in those assets could reasonably have foreseen and factored into their decision-making an increasing emissions price and therefore higher fuel costs over time. However, they would not likely have expected regulation to prevent the use of the asset in which they had already invested. Such foreclosure by regulation seems heavy-handed and Meridian encourages the Government to instead consider reduced emissions unit volumes and therefore higher emissions prices under the ETS to provide coal users with the incentives to discontinue use.

Section 5: Boosting investment in energy efficiency and renewable energy technologies

Meridian agrees that at this stage the Government need not consider additional regulation to force or incentivise investment in clean energy. Meridian considers the ETS with the reforms currently before Parliament to provide adequate incentives for businesses to make investments in clean energy and energy efficiency. If however, the Government does decide to further consider the options in Section 5, Meridian suggests one viable pathway might be to leverage the Corporate Energy Transition Plans and energy audits so that when an energy audit reveals energy efficiency or clean energy investments that have a payback time of less than two or three years then there would be an obligation to either invest in that change or disclose in the Corporate Energy Transition Plan that the investment has not occurred and provide reasons why. Transparency of this kind will encourage businesses to prioritise energy projects that are privately profitable, but which might otherwise remain unimplemented as other, more attractive, more easily quantifiable, or essential to core business projects are prioritised. A comply or explain transparency measure such as this would also not entail the same high costs to Government or to industry as the regulatory requirements or incentives outlined in the discussion document.

Section 6: Cost recovery mechanisms

Meridian supports a levy on coal consumers to the extent that the revenue is of a similar scale to other existing fuel levies and is used to fund policy initiatives to benefit coal consumers, for example co-funding of a low emissions heating feasibility study to switch away from coal and trial a new technology under an expanded EECA Technology Demonstration Fund.

A levy should not be set high in an attempt to create financial incentives to lower coal consumption. That is the role of the ETS and setting too high a levy rate would duplicate the incentives and revenue gathering functions of the ETS.

Section 7: Enabling development of renewable electricity generation under the RMA

Meridian considers decision-making under the RMA to unduly constrain investment in renewable electricity generation because:

- There is weak policy direction in the NPSREG regarding the need to maintain and improve existing renewable electricity generation as well as build new renewables.
- There needs to be effective and efficient processes to enable re-investment in existing renewable generation including wind farms, many of which will reach the end of their lifetime and require investment in new turbines within the next decade.
- There are undue limitations on consent duration. This means that consent lifetimes do not match the lifetimes of the infrastructure for which they are supposedly granted.
- There are short timeframes within which a new consent must be implemented before the consent lapses and a lack of flexibility in how developments are defined, which does not reflect the realities of infrastructure development where technology improves over relatively short timeframes and yet developments can take more than a decade to be build ready.
- There is a lack of policy coherence across policy for climate change, renewable electricity generation, fresh water, indigenous biodiversity, and land use.
- The provisions in Appendix 3 of the National Policy Statement for Freshwater Management (**NPSFM**) are incomplete and the proposal to recognise and protect the generation output of six identified large hydro schemes is not finalised.
- There is ambiguity regarding application of the NPSREG to water allocation and resource use generally.

We discuss these constraints in more detail below.

Improvements to the NPSREG

Meridian strongly agrees that the NPSREG should be amended to provide stronger direction on the national importance of renewables. This should be a priority for the Government. Meridian would welcome further policy development and would be happy to provide expertise and assist with any policy process considering detailed changes to the NPSREG.

Meridian's submission on the Productivity Commissions *Low emissions economy* report suggested a redrafting of the NPSREG, which we have also attached to this submission as Appendix 2. We hope that the suggested changes will be the start of a conversation with policy makers about better national direction for renewable electricity generation developments.

In the draft, we have attempted to show how the existing and emerging weaknesses of the NPSREG could be overcome. In particular, we have:

- worked in specific reference to New Zealand's emissions reduction goals and commitments;
- strengthened the force of the NPSREG by making the language outcome focused rather than process focused;
- integrated generation outcomes and the necessary resource use and protection;
- provided specific direction on the management of environmental effects for renewable electricity generation;
- set out specific direction to support the continuation and enhancement of existing renewable electricity generation; and
- recognised that the NPSREG must support a significant amount of new renewable electricity generation if the Government is to achieve its aims.

A National Policy Statement (**NPS**) under the RMA has an effective life during which it informs and directs the relevant policy and planning documents prepared by councils. Regional and district plans are required to be reviewed by councils every ten years.[8] There is therefore an effective 'life' of a NPS's which encompasses a planning cycle of at least 10 years to be fully effective in decision making. In the next 10 to 13 years the

[8] Resource Management Act, section 79(1).

resource consents for New Zealand's two largest hydro schemes in the Waitaki and Manapōuri catchments will need to be renewed. Additionally, by 2028 it can be expected that many existing wind farms will either need to be repowered or owners of those facilities will need to commit to investment decisions about how, when or possibly whether to repower. New Zealand must not only enable growth in renewable electricity generation but also ensure that existing renewable energy contributions are not undermined. Given the length of a decadal planning cycle, changes to the NPSREG are needed as soon as possible to ensure that the outcomes needed from policy statements, plans, and consenting and reconsenting decisions are delivered. Any reduction in existing renewable generation moves the timeframe, cost and likelihood of achieving a low emissions economy in the wrong direction.

Meridian agrees that amendments to the NPSREG could usefully clarify the relationship with other NPSs and competing national priorities. Policy development affecting renewable electricity generation needs to be coherent and reflect New Zealand's priorities. Neither the NPSREG nor NPSFM have sufficient regard to the importance of climate change or to New Zealand's commitments under the Paris Agreement.

For example, the NPSFM requires, among other things, objectives to maintain and improve freshwater quality and quantity outcomes for lakes and rivers and to meet national bottom lines for freshwater quality. One of the possible outcomes of this policy could involve increased minimum flows or a reinstatement of flows in rivers with hydroelectric infrastructure. This would impact the levels of hydro generation achievable and any future investment in hydro generation. Hydro generation has the ability to very quickly ramp up or down around falls and rises in other types of generation. For example, as wind or solar generation falls away at certain times of the day or year, hydro can ramp up to keep overall electricity supply stable and in line with demand. Because of this, hydro is key to enabling New Zealand to integrate large amounts of intermittent renewables without adversely affecting reliability of supply. Accordingly, if the current level of hydro generation in our system is reduced, this may in turn have the unintended consequence of reducing New Zealand's ability to accommodate and integrate large additional amounts of intermittent renewables into our electricity system and result in other unintended consequences, including:

- electricity cost and security of supply implications; and
- an increase in greenhouse gas emissions from the electricity sector (for example from retention of thermal generation like gas peakers to cover the flexible ramping up and down role played by hydro).

It is therefore essential that the NPSFM Appendix 3 is completed so that councils can make decisions that ensure ongoing operation of existing generation schemes where that best achieves sustainable management taking into account all relevant factors. Appendix 3 of the NPSFM relates directly to hydroelectric infrastructure and is entirely blank, arguably meaning that outcomes like increasing minimum flows will always and inevitably trump the adverse emission reduction, cost, and security of supply effects resulting from any reduction in renewable electricity generation. Yet, existing hydro generation is the core, backbone, or foundation on which New Zealand's flexible, highly renewable, and low-emissions electricity system is based.[9] The NPSREG is also ambiguous as to how it applies to water allocation, which is essential to the effective operation of hydro generation.

A further example is the proposed National Policy Statement on Indigenous Biodiversity (**NPSIB**), which requires each territorial authority to identify and map all Significant Natural Areas (**SNA**) within its district and classify the SNAs as high or medium. The proposed NPSIB includes an exception to allow a range of activity including nationally significant infrastructure developments in medium class SNAs, acknowledging that some infrastructure like renewable electricity generation is essential to the nation and often constrained to specific (and generally remote and undeveloped) areas. There is no similar exception for renewable generation in high class SNAs, meaning that territorial authorities will be required to identify and map areas throughout their districts where it will effectively be impossible to develop renewable electricity generation. Most SNAs will be classed as high value and therefore any effects must be avoided, effectively creating a "no effects" regime. Therefore, the NPSIB could adversely affect the transition to a low emissions economy because of the lack of consenting pathway for renewable energy developments. Geothermal ecosystems are all likely to be identified as high-value SNAs so a specific approach is proposed to accommodate renewable electricity developments in geothermal areas. However, the same issue will arise for many of the remote, exposed ridgelines around New Zealand that offer high quality wind resources. Meridian encourages the Government to consider the impact of blunt 'no-go-zones' around New Zealand for renewable generation developments, and whether in fact a case by case approach as under the status quo might enable renewable generation and significant biodiversity to co-locate where any effects can be avoided or mitigated.

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[9] New Zealand generates 85 percent of electricity from renewable sources and more than 50 percent from hydro (in some years up to 65%).

Various national planning tools such as the New Zealand Coastal Policy Statement, NPSFM, proposed NPSIB and NPSREG create competing and conflicting direction in respect of the same natural resources. The framework is further compounded by the Supreme Court's decision in *King Salmon* where it was held that generally there was no need to revert back to Part 2 of the RMA to make an overall judgment (i.e. a balanced decision) since that must have been a matter considered at the time of drafting the planning provisions and that the specific overrules the general. Since the *King Salmon* decision, policies such as 'avoid', 'protect' and 'safeguard' literally mean exactly that – clear, directive, and unequivocal policies on outcomes will prevail over less directive policies. Therefore, without directive and outcome focused language in the NPSREG, Meridian's view is that the impact of the NPSREG will further diminish relative to other priorities, exacerbating the challenges involved in developing renewable generation and reducing greenhouse gas emissions.

In general decision-making under the RMA is heavily reliant on value judgements. Where there are competing resource management choices, value judgements are required. The role of policy as expressed through instruments (such as plans, regional policy statements and NPS) is to guide and direct those value judgements. NPSs sit at the top of the RMA plan and policy instrument hierarchy and therefore it is appropriate to address such matters via an NPS and reduce the costs and complexity at the local government and Court level when attempting to consent renewable energy projects. If not, there is the significant risk of failing to meet the challenges of climate change because national priorities are not given sufficient weight at the local level.

Efficient and effective processes to manage both existing and new renewable development

For new developments there are issues with consent lapsing timeframes, and the flexibility of consents once granted. For example, section 125 the RMA provides a default lapsing period for resource consents of 5 years from the date of commencement. If this timeframe is not met then the consent will lapse, and a new application is required. There are many factors for renewable generation developers to consider that influence timing, including ensuring demand, prices and other market conditions support the business case for the project. In the time between consenting and construction, technology can also improve, altering the most economic options of configuration of technology for a site and often requiring a new consent application or variation to accommodate the new technology. The lack of flexibility in terms of timeframes and technologies adds costs and complexity to renewable generation projects and makes investment in renewable generation a lot harder than it could be. Overall this lapsing period is generally not sufficient for the orderly investment of capital into new renewable generation projects. As a result, many new renewable development projects seek longer lapsing periods at the time of the resource consent application.

The discussion document proposes National Environmental Standards for Renewable Energy Facilities and Activities to cover a broad range of matters, including:

- standardising the consent process for re-consenting and repowering (upgrading) existing renewable energy generation facilities;
- standardising the consent process for re-consenting consented but unbuilt renewable energy generation facilities, where the existing consent is due to expire and/or consent variations are needed to allow the use of the latest technology;
- prescribing standards for shadow flicker from wind turbines;
- standardising the consent process for small-scale renewable energy projects;
- standardising the consent process for new renewable energy generation proposals; and
- setting out the consenting framework for high voltage lines that are connected to renewables but not part of the National Grid.

Many of these suggestions may have merit and Meridian would welcome further consideration of these options. Standardisation of approach to a specific effect like shadow flicker or windfarm noise is a good idea and warrants further concept development. However, we note that standardisation of process could be very unhelpful where standardisation of processes could risk making consenting and reconsenting processes more difficult in situations where developers have worked hard with local authorities to provide an appropriate enabling planning environment for specific activities. In the context of the discussion document “streamlining” is a better phrase and approach than “standardising”. Meridian therefore considers the priority focus of further policy efforts in this space to be on streamlining processes, so it is simpler and more efficient for renewable developers to carry out their work.

A further option to consider is a form of requiring authority status for renewable electricity developers. Renewable electricity generation is long-lived and nationally significant infrastructure. However, renewable electricity generation is not a network utility operation and accordingly is not able to utilise the requiring authority provisions in the RMA.[10] In this regard it is unusual when compared to many other forms of infrastructure. Development of renewable electricity generation by resource consent drives a narrow focus on a particular infrastructure layout and configuration in order to make effects assessments specific. Also, the duration of consent approvals before they lapse is often short and this is not reasonable given the practical realities and lead in timeframes for development of these types of infrastructure. Greater flexibility and lapsing provisions apply to designations and would be a more effective way in which to enable renewable generation development while still managing impacts and allowing for public participation. Some form of designation process would enable projects to be approved in principle with conditions to manage environmental effects being specified closer to construction once the given technology and specifications of the project are fully scoped. The main point for public participation would be in the initial designation process. Approval of mitigation and conditions could be direct with the relevant council if they are generally in accordance with what was approved in the designation decision. Materially different approaches to mitigation and conditions could require a further public participation step. This would remove many of the barriers to a market led process to identify and develop renewable generation sites. Developers would bear the costs of identifying sites and would have the flexibility needed to develop the most efficient option while still managing adverse effects. An option like this would also avoid many of the pitfalls of a spatial planning and consent-based process such as the picking of winners (and the trade competition issues inherent in picking winners), distortion of land value, higher planning costs being borne by local authorities, lack of flexibility and higher costs for developers.

Consent durations

A related issue is that the maximum duration for a resource consent to use a natural resource is limited to 35 years.[11] Renewable electricity generation assets such as hydro generation have productive lives much longer than 35 years.

Existing hydro schemes are deeply embedded in the environment and are expected to continue in operation for many decades to come. Parts of an existing hydro scheme (i.e. the physical components, dam structures, weirs, ancillary structures) are permitted

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[10] Resource Management Act, sections 166 and 167.
[11] Resource Management Act, section 123.

activities and may lawfully continue to exist as of right in perpetuity. To imagine that nationally important infrastructure is not to be there is unrealistic and fanciful and indeed its removal or significant alteration could only take place in accordance with resource consents (that do not exist). Accordingly, we consider that there is merit for hydro infrastructure being subject to reviews pursuant to section 128 of the RMA as opposed to the necessity of reconsenting *per se*. The recognition of the existing scheme when replacement consents are applied for means that any adverse effects are entirely capable of management through the imposition of appropriate, lawful conditions. Overall the NPSREG fails to give proper direction to decision makers as to the importance of maintaining existing investment in renewable generation. If existing renewable generation is eroded then the challenge of decarbonising the economy will become even greater.

Wind farm turbines have a shorter productive life and may require refurbishment or replacement after 20 to 30 years. There is however a significant investment in a wind farm site that has a much longer and more enduring productive life including: roading, cabling, switchyards and other transmission facilities. In this situation flexibility to allow for the upgrading and redevelopment of the site is important to support least-cost emissions reductions for New Zealand.

Pre-approval options

The discussion document puts forward a number of options that would in some way pre-approve new renewable developments, either through permissive spatial planning, Crown acquisition and transfer of consents, or a statutory allocation process. Meridian does not support any of these options and we agree with MBIE recommendation that these options not be developed further.

Meridian considers that market participants investing capital will have better specialist capability than central or local government when it comes to identifying potential renewable development sites. Considerable expenditure would be required to build a government development capability. The suitability of generation sites is a complex multi-criteria equation factoring in matters such as quality of the renewable resource, proximity of transmission and load, understanding of the existing technology options, nodal electricity prices, land access, geotechnical suitability for development, and access and transport options – to name a few. There would also be many risks if someone other than a developer was to identify appropriate sites, including the picking of winners between different developers with interests in different areas and the raising of expectations and land values in respect of preferred locations (and therefore the costs of any development). Meridian does not see any problems arising from the identification of sites by market participants and agrees with the observation in the discussion document that the effectiveness of these options would be limited because many potential renewable energy sites have already been investigated and many options are already owned by developers.

Section 8: Supporting renewable electricity generation investment

Problem definition

Section 8 of the discussion document begins with identification of a problem that electricity spot prices are simultaneously:

- too high to incentivise accelerated electrification of process heat (or Transport we suggest) on the demand-side; and
- too low to incentivise accelerated deployment of renewable electricity generation on the supply-side.

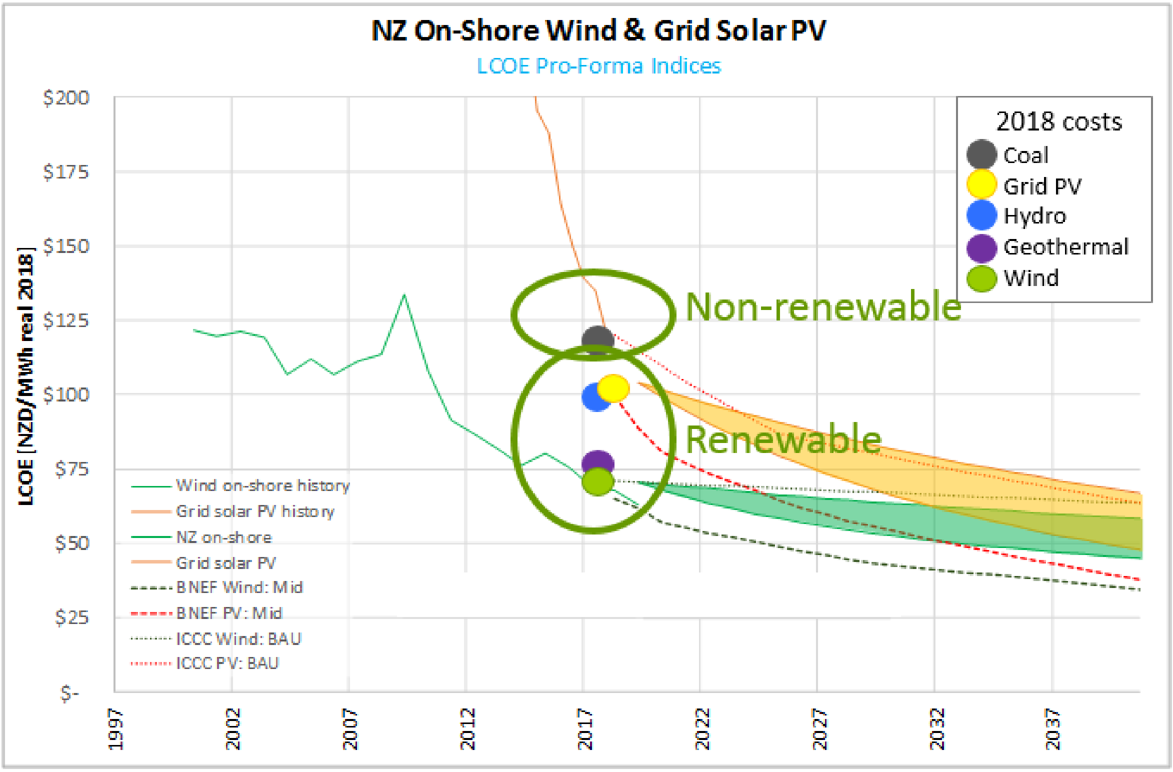
This is simply not the case. On the supply side, market prices and the ETS provide a strong signal to build new renewable generation and renewable options are currently the lowest cost. There are several renewable generation plants currently under construction or in the late stages of being readied for construction, for example:

- Meridian's 160 MW Harapaki wind farm northwest of Napier;
- Tilt Renewable's 130 MW Waipipi wind farm in Taranaki;
- Mercury's 119 MW Turitea wind farm in the Manawatu;
- Contact's drilling campaign at the Tauhara steam field near Taupo, to support a final investment decision on new generation at the site; and
- Construction is underway to expand the Ngawha geothermal power station and more than double the power station's generation capacity to 53 MW.

Nova's 100 MW gas peaking plant at Junction Road in Taranaki has also recently been completed. Gas peaking plant of this kind will help to deliver security of supply in the medium-term and allow for the retirement of thermal baseload generation.

Figure 1 below shows historic and forecast costs for different generation types on a levelized cost of energy basis. As can be seen, renewables are already the least cost development options. With renewable technologies getting cheaper and emissions prices increasing renewables will outcompete thermal generation options by an even wider margin over time.

Figure 1: Generation costs by technology



As has been the case throughout the history of the market, new generation infrastructure will be built to meet demand growth and as older, less efficient plant retires. These investments will be made in a timely and efficient way such that:

- power prices do not increase on average over the long term (consistent with the findings of the Electricity Price Review); and
- security of supply is maintained – New Zealand has not had a country wide interruption to supply since 1992 (well before the establishment of the market) despite several record setting dry years in the period since then.

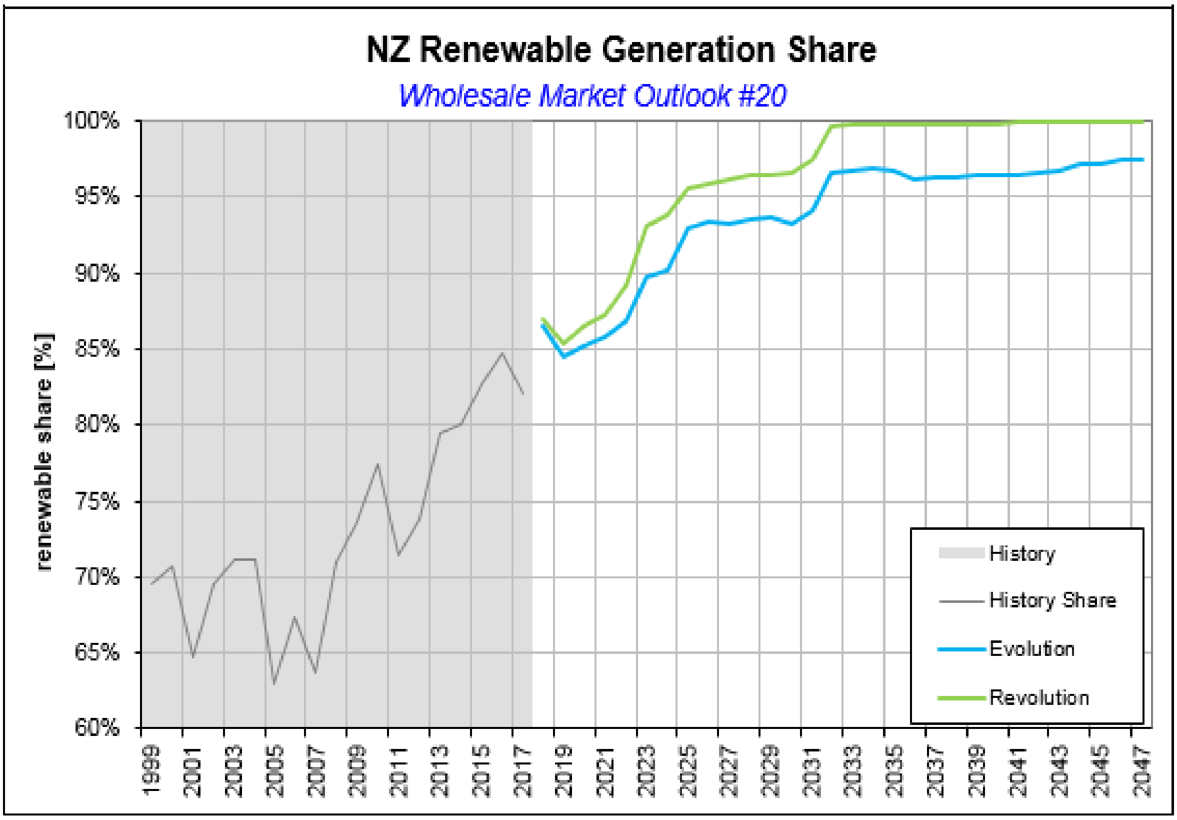
Since 1996, the market has seen the New Zealand electricity sector invest in over 20,000 GWh of new electricity generation at a cost of over $9 billion. This investment has been diversified and has not been dominated by any particular technology or fuel source or by any single company or companies. The risks of these investments are borne by private investors rather than directly by taxpayers. We note:

- ten years ago, around 65 percent of New Zealand's electricity was from renewable sources (compared to around 85 percent today);

- since 2012, 1026 MW of thermal capacity has been retired and replaced by new largely renewable generation; and
- between 2003 and 2014, Meridian commissioned over 400 MW of wind generation.

Modelling by MBIE, the ICCC, Meridian and other parties suggests that the market with no additional intervention will deliver between 90 and 97 percent renewable generation over the next fifteen years and that this can be achieved without significant increases to average power prices.[12] Figure 2 below shows Meridian's evolution and revolution modelling scenarios. The evolution scenario includes an emissions price of \$50/t CO_2e (consistent with the proposed cost containment reserve price in the ETS for the period of the first interim emissions budget). As can be seen this scenario forecasts around 97 percent renewable generation by 2032. Under the revolution scenario with an emissions price of \$100/t CO_2e and higher penetration of demand response 100 percent renewable generation is achieved.

Figure 2: Meridian modelling of New Zealand renewable generation share



[12] For example, MBIE *Electricity demand and generation scenarios* p29; ICCC *Accelerated electrification* p47; Meridian *Wholesale market outlook 2020* extract in Figure 2.

If the Government wants to drive investment in renewable generation more rapidly, then it has all the levers it needs in the ETS and the reforms to it that are currently before Parliament.

On the demand side, it is true that "electricity does not currently compare well with other fuel options on a cost per gigajoule (GJ) basis."[13] However, this is not a problem with electricity prices but a problem of other fuels not adequately factoring in the cost of externalities, specifically their greenhouse gas emissions. Again, if the Government wants to increase the rate of electrification then it has levers available in the ETS and the reforms to it that are currently before Parliament.

The remaining Meridian comments on Section 8 address each of the options in the discussion document. For all these options the fundamental misstatement of the problem definition needs to be kept in mind – Meridian is confident that the market and ETS will deliver increased renewable generation without lifting power prices, ensuring incentives to electrify transport and process heat remain strong.

Introduce a Power Purchase Agreement (PPA) Platform

Meridian does not see any market failure that requires intervention by way of a PPA platform of any kind. There is already a healthy market for PPAs. Recent examples include:

- Meridian's commercial solar PPA offer through which Meridian designs, installs and maintains a solar system for a business. The business has no upfront capital cost but purchases the generation output at an agreed c/kWh rate for the lifetime of the PPA (see Figure 3).
- The arrangement between Tilt Renewables and Genesis Energy for the Waipipi wind farm near Waverly.

[13] MBIE *Accelerating renewable energy and energy efficiency* p68.

Figure 3: Examples of Meridian commercial solar PPA projects

Kiwi Property – Northlands Mall (Christchurch)
Solar Power Purchase Agreement - 185kWp

Lincoln University – Te Kete Ika (Christchurch)
Solar Power Purchase Agreement – 102kWp

There are also active financial markets in New Zealand that can be used to hedge revenue risks for developers of new renewable generation.

Meridian agrees with the observations in the discussion document that PPA platform options involve financial risk and fiscal impact for the Government and risk crowding out private investment. In the absence of any market failure (and we don't believe there is one) it would not make sense to create an administrative entity to run a platform and take on the costs and risk involved.

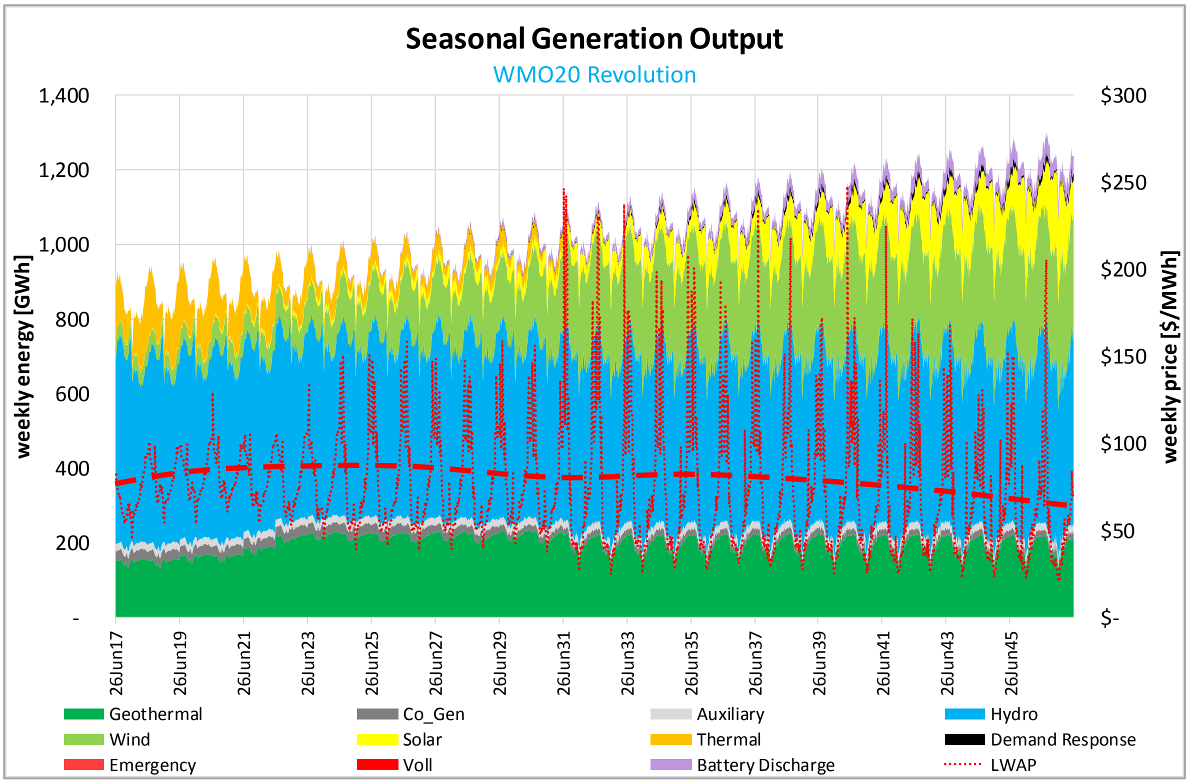
Encourage greater demand-side participation and develop the demand response market

Meridian supports the option to encourage greater demand-side participation and develop the demand response market. Meridian's modelling shows that increasing demand response uptake will be required if the New Zealand electricity sector is to achieve 100 percent renewable generation. Demand response will be required, particularly over winter evening peaks to balance supply and demand and ensure security of supply at much lower cost than other options such as the overbuilding of renewable generation.

Figure 4 below shows Meridian's modelling of the revolution scenario, whereby 100 percent renewable generation is achieved in the next fifteen years. Figure 4 shows the most efficient seasonal mix of generation and demand response to deliver security of supply and maintain power prices. As can be seen, on average, prices are projected to be the same or lower as less efficient plant retires. However, the model predicts greater volatility due to the increasing proportion of intermittent renewables in the system.

Demand response (whether through batteries or some other mechanism) and hydro flexibility will become increasingly important to manage this volatility.

Figure 4: Modelling the seasonal generation and demand response mix



Many existing demand response programmes, such as Transpower's and the ripple control systems employed by distributors, are focused on managing peak network demand and reducing the need for further investment in network infrastructure. This may be why the discussion document links the facilitation of demand response markets with the establishment of a distribution system operator (**DSO**). Meridian certainly sees potential in the idea of a DSO or several DSOs with greater scale and capability than the 29 distribution companies in New Zealand to encourage greater coordination amongst networks and more efficiently coordinate and optimise flexible demand response and other network services. However, Meridian also expects that in future demand response will also likely be the least cost option to manage intermittency and peak energy needs, not just network congestion. We agree that demand response aggregators and virtual power plants will likely need to seek revenue from multiple sources such as the spot market, ancillary services market, electricity retailers, network support service markets, and associated financial markets.

As an example of retailers facilitating demand response – in Victoria, Australia customers of Powershop can join a demand response program whereby Powershop sends a text message in advance of a peak demand event and asks customers to voluntarily curtail usage for a set time. Customers get a $10 discount if they meet a curb target of 10 percent reduction against their baseline usage during the event. Around 20,000 customers are in the programme and uptake in any given event tends to be around 40 percent. For example, in a May 2019 demand response event around 9,000 customers successfully reduced their load by a total of 6 MW over two hours (equivalent to the capacity of approximately 3 large wind turbines like those at West Wind). Retailers have an incentive to pay customers for load reductions if they are exposed to high wholesale spot prices. That incentive will become stronger as the market share of renewable generation increases and wholesale prices become more volatile.

Facilitating the development of demand response markets will take time. Meridian supports the ongoing work of the Electricity Authority to remove barriers to demand response and we believe current market arrangements will generally facilitate the emergence of more sophisticated and varied demand response products. However, targeted support from the Government would be welcome. A range of options exist such as co-funding of feasibility and pilot studies, provision of information about potential markets and business models for demand response providers, and encouraging standardisation of demand response capabilities in new devices as proposed by the Energy Efficiency and Conservation Authority (**EECA**).[14] The focus should be on the provision of information, testing of different models, and removal of barriers so that market participants can develop a range of different products to suit different customers' needs.

The discussion document expresses the view that demand response markets alone will not deliver significant growth in renewables. We disagree. Meridian sees demand response as far more important than the discussion document suggests and considers the encouragement of demand response markets to be the single best option in Section 8 and the best way for the Government to enable a 100 percent renewable electricity system.

[14] https://www.eeca.govt.nz/standards-ratings-and-labels/equipment-energy-efficiency-programme/products-under-the-e3-programme/measures-under-consideration/smart-appliances/.

Deploy energy efficiency resources via retailer or distributer obligations

Meridian does not support an option to require retailers or distributors to fund the deployment of energy efficiency resources. The discussion document suggests the cost would be passed on to customers incrementally, rather than through large upfront costs. The option would undoubtedly raise electricity prices and require electricity retailers to act more like a bank providing credit to customers. It seems unlikely that customers would be better off doing this rather than sourcing credit some other way. The Government and market already provide funding or cheap credit for energy efficiency and heating products, for example:

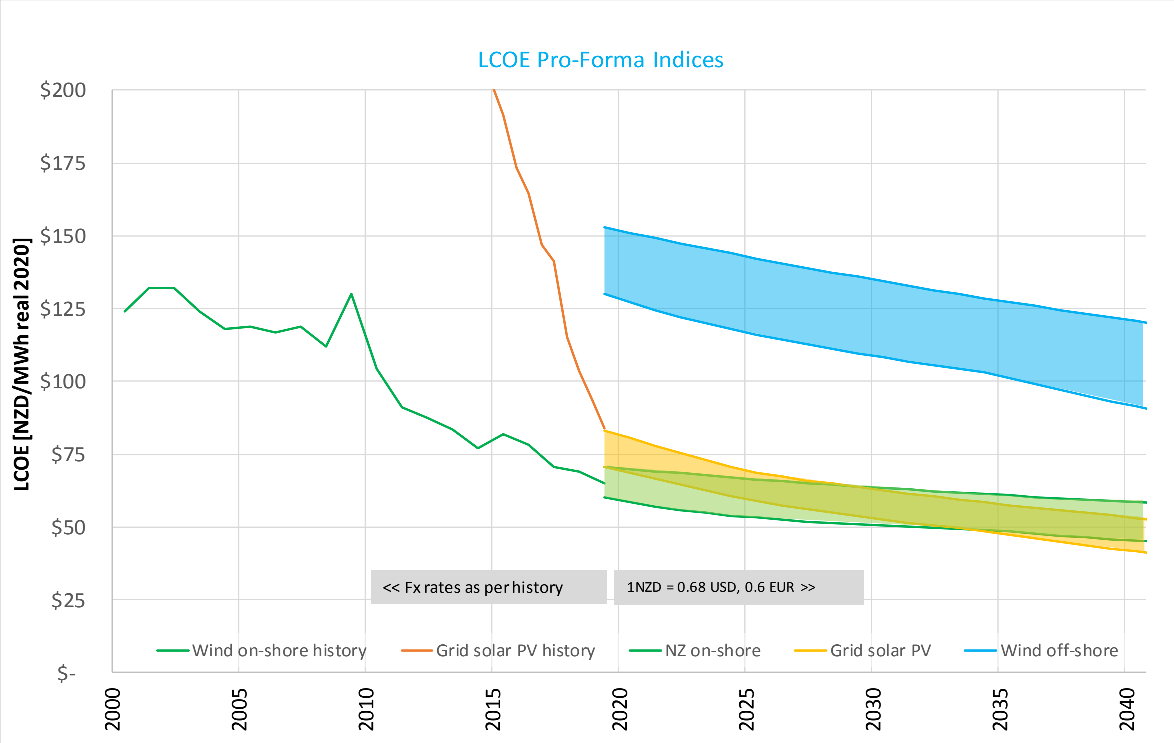
- community services card holders can apply for insulation and heating funding through Warmer Kiwi Homes grants;
- EECA contestable funding for business energy efficiency improvements;
- the healthy homes insulation standard will require landlords to install insulation and efficient heating starting from 1 July 2021;
- Work and Income accepts applications for Advance Payments of Benefit or Recoverable Assistance Payments to non-beneficiaries;
- banks allow energy efficiency improvements to be included on a mortgage and some do so on an interest free basis;
- many local councils allow individuals to pay for insulation and heating investments via rates bills.

Some retailers may choose to offer energy efficiency products and recover the cost through power bills in the same way that some retailers currently offer home appliances with long fixed-term contracts. However, it would be unusually intrusive for the Government to say businesses *must* offer a completely different product to what they currently do or to require customers to purchase that product.

Develop offshore wind assets

Meridian does not support any regulatory or economic requirements to develop offshore wind assets in New Zealand. As indicated below in Figure 5, offshore wind developments are at least double the cost of onshore wind in New Zealand.

Figure 5: Offshore and onshore wind costs and grid solar PV



Building and maintaining an offshore wind development would require a fleet of vessels and helicopters, offshore living quarters for maintenance personnel, and measures to counter the harshness of the marine environment, meaning far higher capital and operating costs. Unlike Europe, New Zealand has outstanding, undeveloped onshore wind resources, making offshore developments unnecessary and reducing any relative advantage offshore developments might have in terms of the quality of the wind resource. Offshore developments would also be novel and would require regulation under both the RMA (within 12 nautical miles) and Exclusive Economic Zone and Continental Shelf (Environmental Effects) Act (beyond 12 nautical miles). The scale required would also not be well suited to the New Zealand market. With wind farms of around a gigawatt necessary to minimise costs, the transmission requirements and effect on the wholesale market would be significant with a binary impact on wholesale prices depending on whether the wind was blowing or not in that one location.

It is unclear how the Government would develop offshore wind unless through direct subsidies, as has been the case in many European jurisdictions. Meridian would not support taxpayer funding of less efficient renewable options given that existing renewable options are already being built by market participants without any support or intervention from the Government. Subsidies would not deliver any better outcome in terms of emissions reduction, would impose significant costs on taxpayers, and would distort the electricity market by crowding out more efficient renewable options and creating massive volatility in wholesale prices.

The discussion document seems to suggest that linking offshore wind developments with green hydrogen production could be an option, for example in Taranaki. A long-term contract price on the back of an offshore wind development would be much higher than for onshore renewable energy options and would in no way deliver cheaper electricity for green hydrogen production.

Introduce renewable electricity certification and portfolio standards

The discussion document describes renewable electricity certificates (**RECs**) consistent with their use in Australian, i.e. a mandatory scheme with retailer targets and links to only recently built renewable generation. However, RECs have evolved in Australia as a secondary option to encourage renewable development in the absence of an effective emissions pricing policy. By contrast, in New Zealand we already have:

- around 85 percent renewable generation and renewables are the least cost option for new generation developments; and
- an emission price under the ETS and proposals currently before Parliament that will strengthen the ETS to be a genuine cap and trade system with higher emissions prices likely to be the outcome over time.

The RECs seen to date in New Zealand therefore are a fundamentally different thing and serve a very different purpose. As noted, RECs of the Australian kind are not needed in New Zealand to incentivise renewables or disincentivise emissions. However, there is strong customer demand in New Zealand for products that leverage New Zealand's existing base of renewable electricity generation. The purpose of the RECs seen to date in New Zealand is to take advantage of our renewable advantage both:

- domestically by enabling energy users to match the quantum of their electricity consumption with generation from specific sources; and
- internationally by attracting multinationals to base their operations in New Zealand.

For example, RE100 is a group of major companies[15] committed to sourcing 100 percent renewable electricity globally. Those companies that have, or are considering locating, offices in New Zealand, demand certified renewable generation. As a nation we would be foolish not to enable global firms like these to take advantage of New Zealand's renewable

[15] http://there100.org/companies.

electricity base and attract businesses, jobs, and potential tax revenues here to our shores.

It is unclear what premium might attach to RECs in New Zealand. However, given the scale of renewable generation in New Zealand, RECs are likely to become more widely available. Any price advantage that renewable generators receive will help to further improve the already strong case for investment in new renewable options relative to thermal options.

The market in New Zealand has delivered certification schemes through NZECS or carboNZero.[16] The Government need not develop a mandatory scheme from scratch. All it need do (if anything) is endorse the existing REC scheme or purchase and operate it. If instead the Government tried to develop an Australian-style mandatory REC scheme in New Zealand the business of the existing schemes would be foreclosed. There would also be significant set up costs, as well as on-going administrative and compliance costs for the Government with little, if any resulting benefit. Renewables are already the least cost option and the Government can adjust the ETS settings if it wants to increase the pace of change. The likelihood of negative interactions between any mandatory, Australian-style REC scheme and the ETS is high, with the potential to drive higher cost emissions abatement at the expense of consumers or taxpayers. Therefore, while Meridian supports Government endorsement of the existing schemes in the market, we are strongly opposed to the adoption of an Australian-style RECs scheme in New Zealand.

Phase down thermal baseload and place in strategic reserve

Meridian does not support any option that seeks to regulate the phase down of baseload thermal generation and place it in strategic reserve controlled by a central planner or market operator. We do not consider there to be a market failure to address as the current market has already proven a success in managing the retirement of thermal plant and its replacement with renewable generation.

This option would likely have significant implications including:

[16] We note that the carboNZero scheme is not a REC scheme as described in the consultation document but enables an organisation or product to be marketed as “zero carbon” by measuring, reducing and then offsetting residual greenhouse gas emissions to achieve a net zero balance. In the case of an electricity product, this may factor in contracts with renewable energy generators or RECs to lower offsetting requirements of the scheme.

- fundamentally altering the design of the electricity market and signalling far more Government intervention;
- creating binary market price signals dictated by decisions of the central planner or market operator to offer in or hold back the baseload thermal plant in reserve;
- the stifling of competition for the provision of thermal generation capacity;
- curtailment of investment in the New Zealand electricity market as a result of the above;
- high implementation costs for Government and taxpayers;
- the potential to lock-in existing baseload thermal generation for far longer than would otherwise be the case in the absence of reserve capacity payments to the operators of that plant; and
- higher costs of emissions abatement relative to what abatement could be achieved via the ETS and current electricity market design.

This strategic reserve option is proposed to address the problem identified in the discussion document that there are no firm commitments to retire thermal baseload and therefore replacement by renewables could happen slowly without intervention, i.e. the Government may want to replace thermal baseload generation with renewables faster than what the market might deliver. Meridian considers the current energy only market, supported by the ETS to be the best way to encourage renewable generation market share. The ETS alters the relative profitability of different types of generation by pricing emissions and therefore increasing the fuel costs of thermal generators. The changes before Parliament will likely increase emissions prices from the current \$25/t CO_2e fixed price option upwards to the proposed \$50/t CO_2e cost containment reserve price – a doubling of emissions prices that thermal generators face.

Meridian also agrees with the Electricity Authority's comments noted in the discussion document:[17]

> "For over 20 years the spot market has operated effectively in providing signals for efficient generation investment, including to manage dry years. This has been supported in more recent years by well-functioning hedge and futures markets that provide parties with the means to enter into forward contracts … without the prescription of a formal capacity mechanism that can be readily gamed."

[17] Productivity Commission's *Low-emissions economy*, p 390.

Meridian's modelling forecasts the retirement of baseload thermal generation between 2023 and 2032 under the evolution scenario at an emissions price of \$50/t CO_2e and with the current energy only market. If the Government wants to see the phase out of thermal generation sooner then it need only lift the cost containment reserve higher and/or constrain the supply of emission units auctioned under the ETS.

If, despite industry feedback, the Government decides to cut across the ETS and intervene more directly in the design of the New Zealand electricity market, then Meridian considers a contestable process for the procurement of reserve capacity to be preferable to an arbitrary decision that locks in existing baseload thermal plant. A contestable process would likely deliver better outcomes for electricity consumers. As noted in the discussion document the strategic reserve option is a variant on a capacity market, but with only two existing baseload thermal plats able to participate in the capacity market.

Meridian commissioned Concept Consulting to consider international experience of both energy-only markets (**EOM**) and capacity markets (**CM**) and compare performance of the two models. The Concept report is attached to this submission as Appendix 3. The report characterises the essential point of difference between the two market designs is that a CM imposes a compulsory contracting obligation on parties who purchase electricity in the spot market. Under this mechanism, a central party forecasts future demand and requires wholesale buyers to hold sufficient forward contracts to meet their net share of projected demand. Concept finds that while CMs provide a high level of assurance that sufficient generation or demand response will be built, they provide less assurance that resources which have been built will actually be available when required. EOMs on the other hand, have performed well in ensuring sufficient capacity is built while also performing better to incentivise resource availability when actually required.

The biggest difference between CMs and EOMs is the level of ex ante assurance they provide, with CMs providing a higher degree of ex ante assurance about the level of built capacity because that factor is under the direct influence of a central planner or market operator. This however comes at a cost and electricity system costs to consumers are higher under CMs than EOMs because:

- CMs are prone to over procurement;
- CMs create weaker incentives to select the most cost-effective mix of supply and demand response options (the reserve mechanism in the discussion document would make no attempt at all to identify the most cost-effective mix of generation and demand response);

- CMs are less able to facilitate and reward innovation – the most important source of cost savings in the long-run – because of the higher level of centralised decision-making and prescription.

Before a CM is seriously considered the Concept report also encourages policy makers to first monitor whether investment adequacy concerns actually emerge and, if they do, whether they can be addressed through tweaks to the EOM rather than through complete redesign of the electricity market, with all the implementation and transition costs that would entail. Meridian sees no need for either a thermal strategic reserve or any broader form of capacity market in the next ten years and considers further consideration of capacity markets in any form undesirable for consumers in the absence of any established problem with security of supply. This is particularly so given already established tools like the ETS exist and disincentivise emissions including those produced by baseload thermal generation.

Other options

The discussion document raises several other options "to demonstrate [MBIE's] wide ranging assessment of possible policy options". Meridian agrees with MBIE's assessment that these options not be recommended for further investigation. Meridian's brief comments on each of these options are set out below.

- Government-sponsored storage facility for firming hedge products: A subsidised hedge product to firm independent and small-scale investment in variable renewables would cost taxpayers, crowd out private investment, distort competition between generators, and displace investment in more efficient renewable options that are economic now without any subsidy. Hedge products are already available to be traded over the counter and via futures markets enabling market participants like intermittent generators to readily and quickly build a portfolio of hedge contracts to stabilise revenue and manage risk.
- State-owned enterprise (**SOE**) for renewables investments: A new SOE would involve high costs to taxpayers. It may also lead to inefficient investment. An SOE would crowd out private investment and transfer investment risk to taxpayers. Any subsidies or other benefits enjoyed by an SOE would weaken competition in the market and result in higher cost investments than the market would otherwise deliver, ultimately at the expense of taxpayers and consumers.

- Co-ordinated procurement of new generation (single market buyer): Government control of investment decisions would result in higher transaction costs and higher risk associated with a loss of diversity of investment. Having diverse procurement of generation by a range of buyers bringing diverse views regarding future supply needs, making it easier to maintain security of supply at least cost to consumers. In contrast, the political incentives of a single-market buyer would likely drive it towards conservatism, hinder innovation, and likely result in over investment in security of supply at the expense of consumers. Meridian considers the high costs and disruption of such fundamental market reform to be high with no resulting benefits.
- Tax incentives for renewable electricity generation or subsidies via auction: As New Zealand's largest renewable generator, Meridian would be well placed to receive the subsidies described. However, Meridian firmly opposes this option. Renewable generation options are already the least cost options and do not require subsidies or incentives to ensure they are built to meet demand and ensure security of supply and return on investment for developers. Subsidies of any kind for renewable generation would be unnecessary, costly for taxpayers, and would likely distort investment leading to the development of less efficient renewable generation plant and higher cost emissions mitigation.

Section 9: Local and community energy engagement

A clear and consistent Government position on community energy issues would be welcomed. Economies of scale mean that small scale renewable developments are higher cost than utility scale. However, Meridian acknowledges individuals and communities have an interest in the transition to a low emissions economy and in greater energy independence and we support this.

Any policy measures targeted at community energy will need to be careful to define the types of projects to support. At one level, the only differences between community energy and any other energy project seem to be scale, and ownership and governance structures. As described in the discussion document, shareholders in a utility power company would also be a "community of interest" – they have a say in and own part of a company and have a shared interest in the success of the company's investments. Otherwise, renewable generators like Meridian and small-scale renewable projects seek the same outcome – investment in new renewable electricity generation.

At a grid scale, companies will invest in the lowest cost renewable generation options. Individual households or communities on the other hand will invest to meet a broader set of objectives including greater independence and resilience or a desire to support renewable generation directly. If the Government is going to invest taxpayer resources in community energy, it needs to be clear why it is doing so. Meridian does not consider investments in community energy will generally be an efficient way to decarbonise the economy or increase the market share of renewable generation in New Zealand (although there may be exceptions). However, if there are other social objectives to be met then support for community energy might be justified.

Support for community energy might also be justified in situations where there is no connection to the national grid, for example to support wind energy developments on Rakiura / Stewart Island or other offshore islands where there is significant diesel generation. In those situations, support for community renewable energy projects will reduce emissions and there will often be no viable option to connect to the grid to access cheaper utility scale renewables. Care should be taken to distinguish such projects from those that remain reliant on the grid for reliability or choose to invest in batteries as well as intermittent renewables to facilitate disconnection from the grid and avoidance of network costs. Community energy projects of these latter types will only displace lower cost utility scale renewable generation and raise power prices for those remaining on the grid, who are likely to be those less able to afford investments in community energy.

Section 10: Connecting to the national grid

The discussion document seeks views on options to address 'first mover disadvantage', 'gaps in publicly available and independent information' and 'lack of information sharing for coordinated investment'. Meridian's view on these matters is that the supposed 'disadvantage,' 'gaps' and 'lack of information' are overstated. The biggest issue in this context in connecting to the national grid is the current method for allocation of grid costs which, as the Electricity Authority has found, is a driver of significant inefficiency and cost across the broader electricity system and is inefficiently disincentivising more use of the existing grid. Addressing deficiencies in the current Transmission Pricing Methodology should be the primary focus of any assessment of how reforms related to the grid can assist in accelerating investment in renewable energy. In particular, we need to adopt a TPM that allows for more optimal use of the current grid and which sends better signals in terms of investments in load and generation that will in future make use of the grid.

We note that discussion document persists in drawing the discredited distinction between connection assets, interconnection assets and HVDC assets. The HVDC assets are merely one particular type or species of interconnection asset and there is no basis, in terms of their role in the electricity system, for drawing a distinction between them and other types of interconnection asset.

We also note the statement that "Because [Transpower] has a regulated income, it generally avoids taking undue risk with grid investments, preferring certainty that its costs will be recoverable." This makes no sense to us and seems to misunderstand how Transpower is regulated. Because Transpower is a regulated entity it actually faces zero risk on the grid investments it makes. It always has complete certainty that its investment costs will be 100 percent recoverable – to ensure this section 44(4) of the Electricity Industry Act 2010 in fact obliges industry participants to pay "any amounts that Transpower charges" that participant and clause 12.78 of the Code states that the purpose of the Transmission Pricing Methodology is to ensure that "the full economic costs of Transpower's services are allocated" to transmission customers. The ultimate check on the prudence or otherwise of Transpower's grid investments, as a regulated entity, is the Commerce Commission and the requirement that the Commission must approve major grid investments, and not uncertainty as to whether grid investments that are unduly risky will be recoverable.

This point is important because the discussion paper seems to proceed on the basis that in order to transition to a low emissions economy Transpower may need to accept a 'higher level of risk' and refers also to risks to Transpower from overspending.[18] Given that Transpower always recovers its investments we suggest the better question to ask is whether, in order to facilitate greater investment, Transpower and ultimately its shareholder (the Crown) are willing to accept a lower level of return in recognition of the need to transition to a low emissions economy.

To illustrate this point, the consultation paper says this in respect of contracted assets:[19]

> "Transpower has indicated that a common 'sticking point' in negotiations is that the budgets and project plans it provides for new connections are indicative and the costs

[18] Pages 102 and 103 of the discussion document. Reference is also made to efficiency incentives but the economic impact of these is negligible in the context of Transpower's overall spend and in fact such incentives can lead to Transpower over-recovering or outperforming against its regulated rate of return.
[19] Page 103

> are uncapped. This is because Transpower seeks to avoid the risk of the new connection costing more than it can recover (construction cost over-runs cannot be recovered through TPM charges)."

This seems to say that the reason that Transpower does not cap costs is because if it did so and the actual costs exceeded the cap they would be irrecoverable. This would in turn reduce the return to Transpower on that contract and ultimately, if spread across all contracts, the return to Transpower's shareholder. Obviously for the party on the other side of that contract this increases the risk (compared to a capped scenario) of doing a deal with Transpower to build the contracted asset.

Our comments on the options discussed in section 10 are below.

Encourage Transpower to include the economic benefits of climate change mitigation in applications for Commerce Commission approval of projects expected to cost over $20m

This option would involve the inclusion of the (avoided) emissions price cost incurred by consumers calculated on a consistent basis. Guidance or direction about the emissions price and trajectory would be needed to support this option.

As we understand it the market benefit test applied already includes emissions costs incurred by generators and other parties that are internal to the electricity market. The issue considered here is whether the test should be extended to include emissions costs incurred or avoided by parties beyond the electricity market. If we have understood the proposal correctly, this would convert the current 'net electricity market benefit' test into a 'net electricity market benefit + non-electricity market ETS-related benefit' test. The question this begs is why other types of non-electricity market benefit (i.e. not just environmental or ETS-related) should not also be included if the desire is to have a more holistic test of the pros and cons of grid investment. Meridian's concern is that, either way, once the test is extended to include non-electricity market benefits, this potentially creates quite a difficult test for the Commerce Commission to apply. Further it's not clear to us that a market benefit test that was adjusted in this way would necessarily result in accelerated renewable generation investment.

Options to address first mover disadvantage

The discussion document outlines several options to address the first mover disadvantage with respect to connection assets. Meridian considers the simplest option to be option 10.3.2, which would provide for Transpower to build larger capacity connection asset or a configuration that allows for growth, but only recover full costs once the asset is fully utilised, with the Crown covering the risk of revenue shortfall, i.e. from a reduced dividend.

Central planning options

Several of the options in the discussion document propose the provision of independent geospatial data on potential generation and electrification sites or maps or databases of potential renewable generation and demand sources and their potential size. All these options imply more of a central planning and coordination role for Transpower or some other Crown organisation. One of the options explicitly suggests a coordination role to force the distribution of wind farms around New Zealand.

Meridian does not support Transpower or any other Crown organisation taking on this sort of role. As a renewable generation developer, we consider there to be sufficient information available to inform our investments. There is also a lot of publicly disclosed information on consented options and options under investigation. Transpower can just as easily access this information and speak to generation developers (through public consultation or informally) if further input into transmission investment decisions would be beneficial.

Any option that seeks to centrally direct or plan when or where generation investments occur in the market would be a significant intervention and would risk a chilling effect on investment. Renewable generation developers are best placed to understand wind and other renewable resources and identify the most economic sites. There are already natural incentives for generators to manage their own portfolio and balance generation to match load across the country.

Section 11: Local network connections and trading arrangements

Meridian agrees that the work programmes already underway across government are adequate to enable connections to, and trading on, distribution networks and that no further policy development is necessary at this time.

Conclusion

Meridian strongly supports further work to strengthen the NPSREG and other options that will streamline consenting and reconsenting processes for renewable electricity developments. We also encourage facilitation of demand response markets as the least cost technology to manage increasing intermittency alongside New Zealand's existing flexible hydro generation.

With respect to energy efficiency measures, Meridian supports Corporate Energy Transition Plans and low-cost, low-risk options such as the provision of better information to energy users and other. We also support the option to ban new coal-fired process heat equipment for low and medium temperature applications. Like the Productivity Commission, we consider options that avoid locking in long-lived and emissions intensive investments to be the priority complementary measures to the ETS. The same level of priority should be given to complementary policies to incentivise electric vehicle uptake and avoid locking in long-lived investments in emissions intensive light transport.

In respect of many of the other options in the paper, Meridian does not consider there to be a problem that needs to be addressed and that the current market, supported by a fully functional ETS, will deliver the outcomes sought by the Government in the most efficient fashion with the least cost to taxpayers and consumers.

Please contact me if you have any queries regarding this submission.

Yours sincerely

Sam Fleming
Regulatory Counsel


Wind. Water. Sun.
The power to make
a difference.

Appendix 1: Responses to consultation questions

	Question	Comment
1.1	Do you support the proposal in whole or in part to require large energy users to report their emissions and energy use annually publish Corporate Energy Transition Plans and conduct energy audits every four years? Why?	Yes. Meridian supports the proposal in whole. Corporate Energy Transition Plans would ideally report on GHG emissions from all energy related Scope 1, 2, and 3 sources. Reporting would audited and published. See Meridian's comments on Section 1 and Section 5 in the body of this submission, where we also suggest that identified energy efficiency or clean energy initiative with short payback periods either required to be implemented or the lack of implementation explained in the Corporate Energy Transition Plans.
1.2	Which parts (set out in Table 3) do you support or not? What public reporting requirements (listed in Table 3) should be disclosed?	We recommend a different measure of scale to annual energy spend which would fluctuate (potentially dramatically) year on year due to changes in energy costs or operating hours. A measure of annual revenue could be an alternative.
1.3	In your view, should the covered businesses include transport energy and emissions in these requirements?	Yes. All emissions from energy related activities should be covered using the principles of the GHG Protocol accounting methodologies.
1.4	**For manufacturers:** what will be the impact on your business to comply with the requirements? Please provide specific cost estimates if possible.	Not applicable.
1.5	In your view, what would be an appropriate threshold to define 'large energy users'?	We consider MBIE and EECA best placed to make this economy wide assessment factoring in different fuel types.
1.6	Is there any potential for unnecessary duplication under these proposals and the TCFD disclosures proposed in the MBIE-MfE discussion document on Climate-related Financial Disclosures?	Yes, there is potential for duplication across various reporting requirements. For further detail see Meridian's comments on Section 1 in the body of this submission.
1.7	Do you support the proposal to develop an electrification information package? Do you support	Meridian supports this option. However, it would not be of use to our business.

	customised low-emission heating feasibility studies? Would this be of use to your business?	
1.8	In your view, which of the components should be scaled and/or prioritised? Are there any components other than those identified that could be included in an information package?	Businesses seeking to electrify will be better placed to respond to this question.
1.9	Do you support benchmarking in the food processing sector?	Yes.
1.10	Would benchmarking be suited to, and useful for, other industries, such as wood processing?	We are uncertain of the value of benchmarking for other industries.
1.11	Do you believe government should have a role in facilitating this or should it entirely be led by industry?	Yes, government may have a role.
2.1	Do you agree that councils have regional air quality rules that are barriers to wood energy? If so, can you point us to examples of those rules in particular councils' plans?	We are uncertain whether this is the case.
2.2	Do you agree that a NESAQ users' guide on the development and operation of the wood energy facilities will help to reduce regulatory barriers to the use of wood energy for process heat?	If feedback reveals a perceived barrier then information provision is a low-cost, low-risk option to help overcome any barriers.
2.3	What do you consider a NESAQ users' guide should cover? Please provide an explanation if possible.	We have no comment at this time.
2.4	Please describe any other options that you consider would be more effective at reducing regulatory	We have no comment at this time.

	barriers to the use of wood energy for process heat.	
2.5	In your opinion, what technical rules relating to wood energy would be better addressed through the NESAQ than through the proposed users' guide (option 2.1)?	We have no comment at this time.
2.6	In your view, could the Industry Transformation Plans stimulate sufficient supply and demand for bioenergy to achieve desired outcomes? What other options are worth considering?	We have no comment at this time.
2.7	Is Government best placed to provide market facilitation in bioenergy markets?	We are unsure whether there is a role for the Government to facilitate bioenergy markets.
2.8	If so, how could Government best facilitate bioenergy markets? Please be as specific as possible, giving examples.	We have no comment at this time.
2.9	In your view, how can government best support direct use of geothermal heat? What other options are worth considering?	We are unsure whether there is a role for the Government to support direct use of geothermal heat.
3.1	Do you agree that de-risking and diffusing commercially viable low-emission technology should be a focus of government support on process heat? Is EECA grant funding to support technology diffusion the best vehicle for this?	Yes. EECA is well placed to do this. However, Meridian suggests avoiding further increases in the electricity levy where possible. An alternative to grant funding would be the provision of interest free Crown loans (currently only available to public sector organisations and administered by EECA).
3.2	**For manufacturers and energy service experts:** would peer learning and on-site technology demonstration visits lead to reducing perceived technology risks? Is there	Not applicable.

	a role for the Government in facilitating this?	
3.3	**For EIHI stakeholders:** What are your views on our proposal to collaborate to develop low carbon roadmaps? Would they assist in identifying feasible technological pathways for decarbonisation?	Not applicable.
3.4	What are the most important issues that would benefit from a partnership and co-design approach?	We have no comment at this time.
3.5	What, in your view, is the scale of resourcing required to make this initiative successful?	We have no comment at this time.
4.1	Do you agree with the proposal to ban new coal-fired boilers for low and medium temperature requirements?	Yes.
4.2	Do you agree with the proposal to require existing coal-fired process heat equipment for end use temperature requirements below 100 degrees Celsius to be phased out by 2030? Is this ambitious or is it not doing enough?	The settings of the ETS can be adjusted to incentivise phase out by existing coal users and achieve this outcome.
4.3	**For manufacturers:** referring to each specific proposal, what would be the likely impacts or compliance costs on your business?	Not applicable.
4.4	Could the Corporate Energy Transition Plans (Option 1.1) help to design a more informed phase out of fossil fuels in process heat? Would a timetabled phase out of fossil fuels in process heat be necessary	We have no comment at this time.

	alongside the Corporate Energy Transition Plans?	
4.5	In your view, could national direction under the RMA be an effective tool to support clean and low GHG-emitting methods of industrial production? If so, how?	We have no comment at this time.
4.6	In your view, could adoption of best available technologies be introduced via a mechanism other than the RMA?	We have no comment at this time.
5.1	Do you agree that complementary measures to the NZ-ETS should be considered to accelerate the uptake of cost-effective clean energy projects?	Yes. However, complementary measures should not duplicate ETS incentives or distort the market for emissions units under the ETS. Like the Productivity Commission, we consider options that avoid locking in long-lived and emissions intensive investments to be the priority complementary measures to the ETS.
5.2	If so, do you favour regulation, financial incentives or both? Why?	Neither, at least in the way described in the discussion document. However, Meridian would support a comply or explain regulatory regime linked to Corporate Energy Transition Plans. For further detail see Meridian's comments on Section 5 in the body of this submission.
5.3	In your view what is a bigger barrier to investment in clean energy technologies, internal competition for capital or access to capital?	Anecdotally, the champions of clean energy or energy efficiency projects are often not in positions of influence and have difficulty communicating the value of energy projects to senior leaders. This indicates internal competition for capital could be an issue. Other stakeholders will be better placed to respond to this question.
5.4	If you favour financial support, what sort of incentives could be considered? What are the benefits, costs and the risks of these incentives?	We have no comment at this time.
5.5	What measures other than those identified above could be effective at accelerating investment in clean energy technologies?	See our response to question 5.2 above.

6.1	What is your view on whether cost recovery mechanisms should be adopted to fund policy proposals in Part A of this document?	Meridian supports a coal levy to fund policy initiatives that benefit coal users like fuel switching feasibility studies. A levy should not attempt to create incentives to lower coal consumption – that is the role of the ETS. For further detail see Meridian's comments on Section 6 in the body of this submission.
6.2	What are the advantages and disadvantages of introducing a levy on consumers of coal to fund process heat activities?	We have no further comment at this time.
7.1	Do you consider that the current NPSREG gives sufficient weight and direction to the importance of renewable energy?	No.
7.2	What changes to the NPSREG would facilitate future development of renewable energy? In particular, what policies could be introduced or amended to provide sufficient direction to councils regarding the matters listed in points a-i mentioned on page 59 of the discussion document?	See Meridian's comments on Section 7 in the body of this submission.
7.3	How should the NPSREG address the balancing of local environmental effects and the national benefits of renewable energy development in RMA decisions?	See Meridian's comments on Section 7 in the body of this submission.
7.4	What are your views on the interaction and relative priority of the NPSREG with other existing or pending national direction instruments?	See Meridian's comments on Section 7 in the body of this submission.
7.5	Do you have any suggestions for how changes to the NPSREG could help achieve the right balance between renewable energy development and	See Meridian's comments on Section 7 in the body of this submission.

	environmental outcomes?	
7.6	What objectives or policies could be included in the NPSREG regarding councils' role in locating and planning strategically for renewable energy resources?	See Meridian's comments on Section 7 in the body of this submission.
7.7	Can you identify any particular consenting barriers to development of other types of renewable energy than REG, such as green hydrogen, bioenergy and waste-to-energy facilities? Can any specific policies be included in a national policy statement to address these barriers?	See Meridian's comments on Section 7 in the body of this submission.
7.8	What specific policies could be included in the NPSREG for small-scale renewable energy projects?	Meridian has no comments specifically on small-scale renewable energy projects. The NPSREG should apply to all renewable electricity generation regardless of scale.
7.9	The NPSREG currently does not provide any definition or threshold for "small and community-scale renewable electricity generation activities". Do you have any view on the definition or threshold for these activities?	We have no comment at this time. Meridian's comments on community energy projects are in Section 9 of the body of this submission.
7.10	What specific policies could be included to facilitate re-consenting consented but unbuilt wind farms, where consent variations are needed to allow the use of the latest technology?	See Meridian's comments on Section 7 in the body of this submission.
7.11	Are there any downsides or risks to amending the NPSREG?	No.
7.12	Do you think National Environmental Standards (NES) would be an effective and appropriate	See Meridian's comments on Section 7 in the body of this submission.

	tool to accelerate the development of new renewables and streamline re-consenting? What are the pros and cons?	
7.13	What do you see as the relative merits and priorities of changes to the NPSREG compared with work on NES?	Amendments to NPSREG should a high priority. See Meridian's comments on Section 7 in the body of this submission.
7.14	What are the downsides and risks to developing NES?	See Meridian's comments on Section 7 in the body of this submission.
7.15	What renewables activities (including both REG activities and other types of renewable energy) would best be suited to NES? For example: • What technical issues could best be dealt with under a standardised national approach? • Would it be practical for NES to set different types of activity status for activities with certain effects, for consenting or re-consenting? For example, are there any aspects of renewable activities that would have low environmental effects and would be suitable for having the status of permitted or controlled activities under the RMA?	See Meridian's comments on Section 7 in the body of this submission.
7.16	Do you have any suggestions for what rules or standards could be included in NES or National Planning Standards to help achieve the right balance between renewable energy	See Meridian's comments on Section 7 in the body of this submission.

	development and environmental outcomes?	
7.17	Would National Planning Standards or any other RMA tools be more suitable for providing councils with national direction on renewables than the NPSREG or NES?	See Meridian's comments on Section 7 in the body of this submission.
7.18	Are there opportunities for non-statutory spatial planning techniques to help identify suitable areas for renewables development (or no go areas)?	See Meridian's comments on Section 7 in the body of this submission.
7.19	Do you have any comments on potential options for pre-approval of renewable developments?	See Meridian's comments on Section 7 in the body of this submission.
7.20	Are the current NPSET and NESETA fit-for-purpose to enable accelerated development of renewable energy? Why?	The current NPSET and NESETA could benefit from improvements. However, we consider there to b higher priorities. We have no further comment at this time.
7.21	What changes (if any) would you suggest for the NPSET and NESETA to accelerate the development of renewable energy?	We have no further comment at this time.
7.22	Can you suggest any other options (statutory or non-statutory) that would help accelerate the future development of renewable energy?	See Meridian's comments on Section 7 in the body of this submission. A further non-statutory option may be to publicly fund campaigns and media on the importance of renewable energy and its role in climate action. This could help to create community and council acceptance of renewable developments, for example by telling the story of communities that have embraced and benefited from renewable developments.
8.1	Do you agree there is a role for government to provide information, facilitate match-making	No.

	and/or assume some financial risk for PPAs?	
8.2	Would support for PPAs effectively encourage electrification and new renewable generation investment?	No. We do not consider there to be any market failure in respect of PPAs. See Meridian's comments on Section 8 in the body of this submission.
8.3	How could any potential mismatch between generation and demand profiles be managed by the Platform and/or counterparties?	We have no further comment at this time.
8.4	What are your views and preferences in relation to different options A to D above?	We have no further comment at this time.
8.5	**For manufacturers:** what delivered electricity price do you require to electrify some or all of your process heat requirements? And, is a long-term electricity contract an attractive proposition if it delivers more affordable electricity?	Not applicable.
8.6	**For investors / developers:** what contract length and price do you require to make a return on an investment in new renewable electricity generation capacity? And, is a long-term electricity contract an attractive proposition if it delivers a predictable stream of revenues and a reasonable return on investment?	Financing and hedging arrangements will vary by project and are commercially sensitive. Risk appetite of a developer will vary based on a range of factors. There are various ways to manage revenue and risk for a renewable generation development. Meridian does not consider there to be any market failure.
8.7	Do you consider the development of the demand response (DR) market to be a priority for the energy sector?	Yes. See Meridian's comments on Section 8 in the body of this submission.
8.8	Do you think that DR could help to manage existing or potential electricity sector	Yes. See Meridian's comments on Section 8 in the body of this submission.

	issues?	
8.9	What are they key features of demand response markets? For instance, which features would enable load reduction or asset use optimisation across the energy system, or the uptake of distributed energy resources?	See Meridian's comments on Section 8 in the body of this submission.
8.10	What types of demand response services should be enabled as a priority? Which services make sense for New Zealand?	See Meridian's comments on Section 8 in the body of this submission.
8.11	Would energy efficiency obligations effectively deliver increased investment in energy efficient technologies across the economy? Is there an alternative policy option that could deliver on this aim more effectively?	There would be investment in energy efficiency but at high cost to consumers. See Meridian's comments on Section 8 in the body of this submission.
8.12	If progressed, what types of energy efficiency measures and technologies should be considered in order to meet retailer/distributor obligations? Should these be targeted at certain consumer groups?	See Meridian's comments on Section 8 in the body of this submission.
8.13	Do you support the proposal to require electricity retailers and/or distributors to meet energy efficiency targets? Which entities would most effectively achieve energy savings?	No.
8.14	Could you or your organisation provide guidance on the likely compliance costs of this policy?	Costs would be high, reflecting the full capital cost of any efficiency investment plus credit risk. Costs would be passed on to consumers. Enforcing compliance with any obligation would also cost the regulator.

8.15	Do you consider the development of an offshore wind market to be a priority for the energy sector?	No. See Meridian's comments on Section 8 in the body of this submission.
8.16	What do you perceive to be the major benefits and costs or risks to developing offshore wind assets in New Zealand?	See Meridian's comments on Section 8 in the body of this submission.
8.17	This policy option involves a high level of intervention and risk. Would another policy option better achieve our goals to encourage renewable energy generation investment? Or, could this policy option be re-designed to better achieve our goals?	The Government could simply endorse the existing NZECS scheme, or purchase and operate it as a government scheme. See Meridian's comments on Section 8 in the body of this submission.
8.18	Should the Government introduce RPS requirements? If yes, at what level should a RPS quota be set to incentivise additional renewable electricity generation investment?	No. See Meridian's comments on Section 8 in the body of this submission.
8.19	Should RPS requirements apply to all retailers and/or major electricity users? What would be an appropriate threshold for the inclusion of major electricity users (i.e. annual consumption above a certain GWh threshold)?	No. See Meridian's comments on Section 8 in the body of this submission.
8.20	Would a government backed certification scheme support your corporate strategy and export credentials?	Government endorsement or operation of the existing NZECS scheme would support Meridian's business and that of our customers and provide some assurance regarding policy stability going forward. An Australian-style scheme would be counter-productive
8.21	What types of renewable projects should be eligible	The existing NZECS scheme enables certification for all generation. An Australian-style scheme with

	for renewable electricity certificates?	eligibility limited to renewable generation developments after a certain date would provide no benefit in New Zealand. See Meridian's comments on Section 8 in the body of this submission.
8.22	If this policy option is progressed, should retailers and major electricity users be permitted to invest in energy efficient technology investments to meet their renewable portfolio standards? (See option 8.3 above on energy efficiency obligations).	See Meridian's comments on Section 8 in the body of this submission.
8.23	Could you or your organisation provide guidance on the likely administrative and compliance costs of this policy?	See Meridian's comments on Section 8 in the body of this submission.
8.24	This policy option involves a high level of intervention and risk. Do you think that another policy option could better achieve our goals to encourage renewable energy generation investment? Or, could this policy option be redesigned to better achieve our goals?	Meridian does not support this option. See Meridian's comments on Section 8 in the body of this submission.
8.25	Do you support the managed phase down of baseload thermal electricity generation?	Meridian considers the current market capable of managing the retirement of baseload thermal generation. The market has successfully managed many similar periods of generation retirements in the past. See Meridian's comments on Section 8 in the body of this submission.
8.26	Would a strategic reserve mechanism adequately address supply security and reduce emissions affordably during a transition to higher levels of renewable electricity generation?	No. See Meridian's comments on Section 8 in the body of this submission.
8.27	Under what market conditions should thermal baseload held in a strategic reserve be used?	Meridian does not support this option. This question reveals some of the difficulty of a central planner making decisions in the market. See Meridian's comments on Section 8 in the body of

	For example, would you support requiring thermal baseload assets to operate as peaking plants or during dry winters?	this submission.
8.28	What is the best way to meet resource adequacy needs as we transition away from fossil fueled electricity generation and towards a system dominated by renewables?	The current market has already transitioned from 65 to 85 percent renewable and managed the retirement of significant thermal generation. All while maintaining security of supply and without raising long-term average electricity prices. See Meridian's comments on Section 8 in the body of this submission.
8.29	Should a permanent capacity market which also includes peaking generation be considered?	No. See Meridian's comments on Section 8 in the body of this submission and the Concept Consulting report appended to this submission.
8.30	Do you have any views regarding the above options to encourage renewable electricity generation investment that we considered, but are not proposing to investigate further?	Meridian does not support these options. See Meridian's comments on Section 8 in the body of this submission.
9.1	Should New Zealand be encouraging greater development of community energy projects?	There may be some scope for targeted Government support for community energy projects. See Meridian's comments on Section 9 in the body of this submission.
9.2	What types of community energy project are most relevant in the New Zealand context?	See Meridian's comments on Section 9 in the body of this submission.
9.3	What are the key benefits and downsides/risks of a focus on community energy?	See Meridian's comments on Section 9 in the body of this submission.
9.4	Have we accurately identified the barriers to community energy proposals? Are there other barriers to community energy not stated here?	Yes. In general, these are not regulatory barriers but rather the result of limited access to capital and expertise. See Meridian's comments on Section 9 in the body of this submission.
9.5	Which barriers do you consider most significant?	We have no further comment at this time.
9.6	Are the barriers noted above in relation to electricity market	Yes.

	arrangements adequately covered by the scope of existing work across the Electricity Authority and electricity distributors?	
9.7	What do you see as the pros and cons of a clear government position on community energy, and government support for pilot community energy projects?	A clear Government position would be useful but is unlikely to persist through multiple terms of government. See Meridian's comments on Section 9 in the body of this submission.
9.8	Any there any other options you can suggest that would support further development of community energy initiatives?	Meridian supports targeted government assistance for community energy projects where connection to the grid is unlikely to be an option and diesel generation is currently relied upon (for example on Rakiura / Stewart Island). Most other community energy projects will simply be displacing lower cost grid scale renewable energy. See Meridian's comments on Section 9 in the body of this submission.
10.1	Which option or combination of options proposed, if any, would be most likely to address the first mover disadvantage?	Option 10.3.2. See Meridian's comments on Section 10 in the body of this submission.
10.2	What do you see as the disadvantages or risks with these options to address the first mover disadvantage?	See Meridian's comments on Section 10 in the body of this submission.
10.3	Would introducing a requirement, or new charge, for subsequent customers to contribute to costs already incurred by the first mover create any perverse incentives?	See Meridian's comments on Section 10 in the body of this submission.
10.4	Are there any additional options that should be considered?	See Meridian's comments on Section 10 in the body of this submission.
10.5	Do you think that there is a role for government to provide more independent public data? Why or why	Only to the extent that a need for the information is identified and the benefits of the information exceed the costs of providing it. See Meridian's comments on Section 10 in the body of this

	not?	submission.
10.6	Is there a role for Government to provide independent geospatial data (e.g. wind speeds for sites) to assist with information gaps?	No. See Meridian's comments on Section 10 in the body of this submission.
10.7	Should MBIE's EDGS be updated more frequently? How often?	We have no comment at this time.
10.8	Should MBIE's EDGS be more granular, for example, providing information at a regional level?	We have no comment at this time.
10.9	Should the costs to the Crown of preparing EDGS be recovered from Transpower, and therefore all electricity consumers (rather than tax-payers)?	We have no comment at this time.
10.10	Would you find a users' guide helpful? What information would you like to see in such a guide? Who would be best placed to produce a guide?	No. But other parties may. See Meridian's comments on Section 10 in the body of this submission.
10.11	Do you think that there is a role for government in improving information sharing between parties to enable more coordinated investment? Why or why not?	No. See Meridian's comments on Section 10 in the body of this submission.
10.12	Is there value in the provision of a database (and/or map) of potential renewable generation and new demand, including location and potential size? If so, who would be best to develop and maintain this? And how should it be funded?	No. See Meridian's comments on Section 10 in the body of this submission.
10.13	Should measures be introduced to enable coordination regarding the	No. See Meridian's comments on Section 10 in the body of this submission.

	placement of new wind farms?	
10.14	Are there other information sharing options that could help address investment coordination issues?	No. See Meridian's comments on Section 10 in the body of this submission.
11.1	Have you experienced, or are you aware of, significant barriers to connecting? Are there any that will not be addressed by current work programmes outlined above?	We are not aware of any barriers to connecting that are not already covered by existing work programmes.
11.2	Should the section 10 option to produce a users' guide extend to the process for getting an upgraded or new distribution line? Are there other section 10 information options that could be extended to include information about local networks and distributed generation?	Such a guide may be difficult to produce given differences between distribution networks and the processes that each follows.
11.3	Do the work programmes outlined above cover all issues to ensure the settings for connecting to and trading on the local network are fit for purpose into the future? Are there things that should be prioritised, or sped up?	Yes, the existing work programmes seem appropriate.
11.4	What changes, if any, to the current arrangements would ensure distribution networks are fit for purpose into the future?	We have no further comment at this time.

Appendix 2: Redrafted NPSREG

Appendix 3: Concept Consulting report on capacity and energy-only markets

Suggested Redraft

NATIONAL POLICY STATEMENT

For Renewable Electricity Generation

Preamble

This national policy statement sets out an objective and policies to enable the sustainable management of renewable electricity generation under the Resource Management Act 1991 ('the Act').

New Zealand's energy demand has been growing steadily and is forecast to continue to grow. New Zealand must confront two major energy challenges as it meets growing energy demand. The first is to respond to the risks of climate change by reducing greenhouse gas emissions caused by the production and use of energy. This includes meeting New Zealand's international obligations, most recently the Paris Agreement, to reduce greenhouse gas emissions and transition to a long-term low emission economy. The second is to deliver clean, secure, affordable energy while treating the environment responsibly.

The contribution of renewable electricity generation, regardless of scale, towards addressing the effects of climate change plays a vital role in the wellbeing of New Zealand, its people and the environment. This will include an important role in assisting other parts of the economy, particularly transport and industry, to replace fossil fuels with renewable energy sources.

In considering the risks and opportunities associated with various electricity futures, central government has renewed, and committed to, its strategic target that 100 percent of electricity generated in New Zealand should be derived from renewable energy sources by 2035 (based on delivered electricity in an average hydrological year) providing this does not affect security of supply.

New Zealand has formalised its first commitment under the Paris Agreement to reduce its greenhouse gas emissions by 30 percent below 2005 levels by 2030. The Government has previously notified a target for a 50 per cent reduction in New Zealand greenhouse gas emissions from 1990 levels by 2050 and that a carbon neutral economy is established by 2050.

Development that increases renewable electricity generation capacity can have positive and adverse environmental effects that span local, regional, national and global scales, often with adverse effects manifesting locally and positive effects manifesting nationally and globally. Encouraging electricity generation from renewable energy sources is necessary to achieve long-term reductions in dependence on non-renewable resources and the production of greenhouse gas emissions. The positive effects derived from renewable electricity generation should be recognised when considering provisions, standards or proposals that may affect its development or operation.

Small and community-scale distributed renewable electricity generation, domestic-scale energy efficiency and alternative energy sources will contribute to a reduction of energy consumption and use of non-renewable energy sources. However, large-scale renewable electricity generation will also be required to meet the government's target of achieving 100 per cent renewable electricity generation by 2035 and to satisfy the growing energy demand for renewable electricity for a carbon neutral economy by 2050.

Large scale renewable electricity generation can have adverse environmental effects. For example, wind energy generation, by necessity, are located in open, usually prominent, locations where the wind resource is available and this can give rise to adverse landscape and amenity effects. Hydro-electricity generation can adversely affect ecological, landscape and tangata whenua values within catchments. Facilities for the transmission of the generated electricity to the national grid may also be necessary, with potential for adverse environmental effects. Accordingly, there can be tensions between the values of these areas and the potential adverse effects of large scale renewable electricity generation.

Therefore, the national and global benefits of renewable electricity generation must compete evenly with matters of national importance as set out in section 6 of the Act, and with matters to which decisionmakers are required to have particular regard under section 7 of the Act. In particular, the natural resources from which electricity is generated can coincide with areas of significant natural character, significant amenity values, historic heritage, outstanding natural features and landscapes, significant indigenous vegetation and significant habitats of indigenous fauna. There can also be potential conflicts with the relationship of Maori with their taonga and the role of kaitiaki.

Title

This national policy statement is the National Policy Statement for Renewable Electricity Generation xxxx.

Commencement

This national policy statement will take effect xxxx.

Interpretation

In this national policy statement, unless the context otherwise requires:

Act means the Resource Management Act 1991.

Decision-makers means all persons exercising functions and powers under the Act.

Distribution network means a distributor's lines and associated equipment used for the conveyance of electricity on lines other than lines that are part of the national grid.

Distributor means a business engaged in distribution of electricity.

National grid means the lines and associated equipment used or owned by Transpower to convey electricity.

Renewable electricity generation means generation of electricity from solar, wind, hydroelectricity, geothermal, biomass, tidal, wave, or ocean current energy sources, and the development, operation, maintenance and upgrade of the structures and activities associated with this generation. This includes small and community-scale distributed renewable generation and the system of electricity conveyance required to convey electricity to the distribution network and/or the national grid and electricity storage technologies associated with renewable electricity

Small and community-scale distributed electricity generation means renewable electricity generation for the purpose of using electricity on a particular site, or supplying an immediate community, or connecting into the distribution network.

Terms given meaning in the Act have the meanings so given.

Matters of national significance

This national policy statement is about recognising the national significance of renewable electricity generation, and in particular:

a) the nationally significant role of renewable electricity generation in the achievement of New Zealand's obligations and targets for the reduction of greenhouse gas emissions;

b) the need to develop, operate, maintain and upgrade existing, and substantial new, renewable electricity generation throughout New Zealand; and

c) the benefits of renewable electricity generation and that these cannot be achieved without adverse environmental effects.

Objective

To recognise the national significance of renewable electricity generation by providing for the development, operation, maintenance and upgrading of new and existing renewable electricity generation that enables:

a) long-term generation from existing renewable electricity generation, and maintains and where practicable increases its generation output and operational flexibility; and

b) significant generation output and operational flexibility from new renewable electricity generation;

such that the proportion of New Zealand's electricity generated from renewable energy sources increases to a level that meets or exceeds the New Zealand Government's national target for renewable electricity generation, and its international obligations for reduction in greenhouse gas emissions.

A. Recognising and providing for the benefits of renewable electricity generation

POLICY A1

Regional policy statements and regional and district plans shall include objectives, policies and methods which recognise and provide for renewable electricity generation including the national, regional and local benefits relevant to renewable electricity generation, and which give effect to the objective of this national policy statement. These benefits include, but are not limited to:

a) maintaining and increasing electricity generation capacity while avoiding, reducing or displacing greenhouse gas emissions;

b) enabling other parts of the economy, particularly transport and industry, to transition from fossil fuels to renewable energy sources;

c) maintaining or increasing resilience, security and reliability of electricity supply at local, regional and national levels by diversifying the type and/or location of electricity generation;

d) using renewable natural resources rather than finite resources;

e) the reversibility of the adverse effects on the environment of some renewable electricity generation technologies; and

f) avoiding reliance on imported fuels for the purposes of generating electricity.

POLICY A2

When considering applications for resource consents for renewable electricity generation, every decision-maker shall recognise and provide for the national, regional and local benefits relevant to renewable electricity generation, including, but not limited to, those listed in Policy A1.

B. Addressing the practical implications of achieving New Zealand's targets for electricity generation from renewable resources and its international obligations for reduction in greenhouse gas emissions

POLICY B

When making or changing policy statements and plans to give effect to this national policy statement, and when considering applications for resource consents for renewable electricity generation, every decision-maker shall:

a) protect the assets, operational capacity and continued availability of the renewable energy resource of existing renewable electricity generation, in order to maintain and, where practicable, enable an increase in its generation output and operational flexibility; and

b) maintain the generation output and operational flexibility of existing renewable electricity generation as even minor reductions can cumulatively have significant adverse effects on national, regional and local renewable electricity generation output; and

c) enable the long-term operation of existing renewable electricity generation; and

d) encourage existing renewable electricity generation to increase the efficiency of its generation output and operational flexibility; and

e) provide for the significant development of additional renewable electricity generation, as this will be required for New Zealand to meet or exceed its national targets for the generation of electricity from renewable resources, and its international obligations for reduction in greenhouse gas emissions.; and

f) ensure that resource consents for the existing or new renewable electricity generation are granted for the maximum term, in recognition of its national significance and significant value of the investment.

C. Addressing the constraints associated with the development, operation, maintenance and upgrading of new and existing renewable electricity generation

POLICY C1

When making or changing policy statements and plans to give effect to this national policy statement, and when considering applications for resource consents for renewable electricity generation, every decision-maker shall recognise and provide for the following:

a) the need to locate renewable electricity generation where the renewable energy resource is available;

b) logistical or technical practicalities associated with developing, upgrading, operating or maintaining renewable electricity generation;

c) the significant value of the investment in existing renewable electricity generation and the benefits from continued and, where practicable, increased renewable electricity generation from that investment;

d) the location of existing structures and infrastructure including, but not limited to, roads, navigation and telecommunication structures and facilities, the distribution network and the national grid in relation to renewable electricity generation, and the need to connect renewable electricity generation to the national grid;

e) the long time periods required for the orderly and practical development of new, or maintenance or upgrading of existing, renewable electricity generation and the need for lapsing periods for resource consents that exceed the minimum period;

f) designing measures which allow operational requirements to complement and provide for mitigation opportunities; and

g) adaptive management measures.

POLICY C2

When making or changing policy statements and plans to give effect to this national policy statement, and when considering applications for resource consents for renewable electricity generation, every decision-maker shall consider existing renewable electricity generation and its associated use of, and effects on, natural and physical resources as part of the existing environment.

D. Managing environmental effects of renewable electricity generation

POLICY D1

When considering any residual environmental effects of renewable electricity generation, decision-makers shall have regard to:

a) the extent to which avoidance, remedying or mitigation of adverse effects is constrained by functional and operational needs of renewable electricity generation, and the need for resilient, secure and reliable electricity supply at local, regional and national levels;

b) the significant scale of generation output and operational flexibility from renewable electricity generation that will be required for New Zealand to meet or exceed its national targets for the generation of electricity from renewable resources, and its international obligations for reduction in greenhouse gas emissions;

c) an applicant's proposed offsetting measures or environmental compensation including measures or compensation which benefit the local environment and community affected.

POLICY D2

When making or changing policy statements and plans to give effect to this national policy statement, and when considering applications for resource consents for renewable electricity generation, every decision-maker shall:

a) rely on compliance with a relevant New Zealand standard as demonstrating that the effects on the environment are acceptable and as establishing the appropriate level of compliance;

b) recognise and promote the use of New Zealand Standards, environmental management codes of practice and best practice methods in energy generation, distribution and use; and

c) in particular when managing noise effects from wind energy generation, implement any relevant New Zealand Standard.

E. Managing adverse effects on renewable electricity generation

POLICY E

Decision-makers shall, to the extent reasonably possible, manage activities to avoid adverse effects on consented and on existing renewable electricity generation.

F. Incorporating provisions for renewable electricity generation into regional policy statements and regional and district plans

F1 Solar, biomass, tidal, wave and ocean current resources

POLICY F1

Regional policy statements and regional and district plans shall include objectives, policies and methods (including rules within plans) to provide for the development, operation, maintenance, and upgrading of new and existing renewable electricity generation using solar, biomass, tidal, wave and ocean current energy resources to the extent applicable to the region or district.

F2 Hydro-electricity resources

POLICY F2

Regional policy statements and regional and district plans shall include objectives, policies, and methods (including rules within plans) to provide for the development, operation, maintenance, and upgrading of new and existing hydro-electricity generation to the extent applicable to the region or district.

F3 Wind resources

POLICY F3

Regional policy statements and regional and district plans shall include objectives, policies, and methods (including rules within plans) to provide for the development, operation, maintenance and upgrading of new and existing wind energy generation to the extent applicable to the region or district.

F4 Geothermal resources

POLICY F4

Regional policy statements and regional and district plans shall include objectives, policies, and methods (including rules within plans) to provide for the development, operation, maintenance, and upgrading of new and existing electricity generation using geothermal resources to the extent applicable to the region or district.

G. Incorporating provisions for small and community-scale distributed renewable electricity generation into regional policy statements and regional and district plans

POLICY G

As part of giving effect to Policies F1 to F4, regional policy statements and regional and district plans shall include objectives, policies, and methods (including rules within plans) to provide for the development, operation, maintenance and upgrading of small and community-scale distributed renewable electricity generation from any renewable energy source to the extent applicable to the region or district.

H. Enabling identification of renewable electricity generation possibilities

POLICY H

Regional policy statements and regional and district plans shall include objectives, policies, and methods (including rules within plans) to provide for activities associated with the investigation, identification and assessment of potential sites and energy sources for renewable electricity generation by existing and prospective generators.

I. Time within which implementation is required

POLICY I1

Unless already provided for within the relevant regional policy statement or proposed regional policy statement, regional councils shall give effect to Policies A, B, C, D, E, F, G and H by notifying using Schedule 1 of the Act, a change or variation (whichever applies) within 24 months of the date on which this national policy statement takes effect.

POLICY I2

Unless already provided for within the relevant regional or district plans or proposed plans, plan changes or variations, local authorities shall give effect to Policies A, B, C, D, E, F, G and H by notifying using Schedule 1 of the Act, a change or variation (whichever applies) within the following timeframes:

a) where the relevant regional policy statement or proposed regional policy statement already provides for the Policies, 24 months of the date on which this national policy statement takes effect; or

b) where a change or variation to the regional policy statement or proposed regional policy statement is required by Policy I1, 12 months of the date on which the change or variation becomes operative.

Monitoring and reviewing the implementation and effectiveness of the national policy statement

To monitor and review the implementation and effectiveness of this national policy statement in achieving the purpose of the Act, the Minister for the Environment should:

- in collaboration with local authorities and relevant government agencies collect data for, and, as far as practicable, incorporate district and regional monitoring information into a nationally consistent monitoring and reporting programme, including monitoring the performance of local authorities against the timeframes for giving effect to this national policy statement;
- utilise other information gathered or monitored that assists in measuring progress towards the Government's national target for the generation of electricity from renewable sources;
- within five years of its taking effect, and thereafter as considered necessary, assess the effect of this national policy statement on relevant regional policy statements and regional

or district plans, resource consents and other decision-making; and

- publish a report and conclusions on matters above.

Capacity markets and energy-only markets – a survey of recent developments

February 2020

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Concept Consulting Group Ltd (Concept) specialises in providing analysis and advice on energy, infrastructure and environmental issues. Since its formation in 1999, the firm's personnel have advised clients in New Zealand, Australia, the wider Asia-Pacific region. Clients have included consumers, regulators, suppliers, governments, and international agencies.

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Contents

1 Executive summary

What this paper is about

Ever since wholesale electricity markets were established in the 1990s, there has been debate about the relative merits of the ‘energy-only market’ (EOM) design and the alternative ‘capacity market’ (CM) design. The essential point of difference is that a CM imposes a compulsory contracting obligation on parties who purchase electricity in the spot market. Under this mechanism, a central party forecasts future demand and requires wholesale buyers to hold sufficient forward contracts to meet their net share of projected demand (see Chapter 3 for a fuller description of the structure of the two models).

Debate about the merits of the approaches has intensified in recent years – particularly as nations accelerate their efforts to reduce greenhouse gas emissions. The debate has produced a burgeoning list of reports and developments including:

- ISO New England and PJM made substantial changes to their CMs after 2015 to improve operational performance (see section 4.5)
- The European Union competition authority conducted an inquiry into capacity mechanisms in 2016 because of concerns about their potential effect on competition (see section 5.3)
- Eastern Australia considered in 2016-17 whether to adopt a CM but chose to modify its EOM (see section 4.3.3)
- Britain suspended its capacity mechanism in 2018, after the European Court found it potentially breached competition rules. The scheme was reinstated in 2019 (see section 4.2.3)
- A United States Federal Energy Regulatory Commissioner expressed serious doubts in 2019 about the effectiveness of current CMs (see section 5.4)
- Singapore is planning to replace its EOM with a CM from 2022 (see section 4.3.6)
- Alberta decided in 2014 to replace its EOM with a CM from 2021, and then abandoned that decision in July 2019 (see section 4.3.2).

In this report, we compare the performance of the two models – drawing on recent international experience and literature.

CMs and EOMs have different strengths in relation to reliability

CMs provide a high level of assurance that sufficient generation and demand-side response (DR) will be *built.* This is because CMs create explicit commitments to invest in supply or DR capability. CMs can also include tests to ensure that parties’ commitments are backed by ‘steel in the ground’. Having said that, many EOMs (e.g. New Zealand, Nord Pool, Singapore) have performed well in ensuring sufficient capacity is *built*. So, the real difference between CMs and EOMs is the level of ex ante assurance they provide. CMs provide a higher degree of ex ante assurance about the level of *built* capacity because that factor is under the direct influence of the regulator/market operator.

Turning to operational issues, CMs do not provide assurance that resources which have been *built* will actually be *available* when required. Indeed, experience to date suggests that EOMs will almost certainly perform better than CMs on this front, because EOM spot prices create stronger signals to make all supply and DR resources available during periods of scarcity.

Given that the two designs have different strengths with regard to reliability, the overall assessment of the two designs on this front is not clear-cut. Policy makers need to carefully consider which issue is likely to be most important – obtaining ex ante assurance about the level of *built* capacity, or ensuring that resources which have been built will be *available* when required. In the case of New

Zealand, the latter issue appears to have been the more critical one - given the energy-constrained nature of our electricity system.

CMs tend to raise costs for consumers

Costs to consumers are expected to be higher under CMs than EOMs. The key reasons are:

- CMs are prone to over procurement. Key decisions must be made by a central party who will face lop-sided incentives. They will typically err on the side of caution because any failure in the form of power cuts will be visible, whereas the costs of over-building are harder to see.
- CMs create weaker incentives to select the most cost-effective mix of supply and DR options. This is because the central party will significantly influence the resource mix, but doesn't directly face the cost of its decisions. For example, the central party would need to decide what proportion of each wind generators' nameplate capacity will qualify as firm capacity. In truth, the answer depends on factors such as a generator's location and the extent to which wind patterns in that area are correlated with wind patterns elsewhere. But the central party may prefer a simple 'one-size-fits-all' rule because of the complexities of a more detailed assessment. That in turn would encourage parties to invest in a resource mix that reflects the CM's rules, rather than the mix that genuinely provides the firm capacity at least cost.
- CMs are less able to facilitate and reward innovation – the most important source of cost savings in the long-run – because of the higher level of centralised decision-making and prescription.

Market power

Some commentators argue that CMs insulate purchasers from the exercise of market power in the spot market because all purchasers are heavily contracted. However, other commentators argue that CMs exacerbate market power in the contracts market. In our view, neither model has an overwhelming advantage on the competition front, and both require careful design to minimise the scope for the exploitation of market power.

Durability

In theory, CMs should be more durable than EOMs because they do not rely on spot prices being able to reach very high levels in a scarcity event. However, because of poor operational performance during past scarcity events, leading CMs are moving toward penalty regimes which mimic scarcity prices under an EOM. So, the difference in durability from this source may lessen over time.

More generally, where CMs have been adopted, they are under almost constant change by the central decision maker – with some modifications being very significant. Furthermore, experience suggests CMs are more exposed than EOMs to legal or regulatory challenges due to the greater centralisation of decision-making and considerable administrative discretion conferred on the central party.

What should New Zealand do?

Neither EOMs nor CMs are perfect. Both have strengths and weaknesses – and experience is still being accumulated on their relative performance. Based on the international experience with EOMs and CMs to date, we suggest the following actions.

Keep an eye ahead

New Zealand should keep an eye ahead for any sign of potential or emerging problems. Identifying concerns at an earlier stage provides more time for careful examination to determine if problems are real or perceived (see below). If concerns are borne out, early identification also gives more time for proper diagnosis of causes, and identification of solutions.

New Zealand already has tools to facilitate monitoring of the forward outlook for supply and demand. These should be actively employed – focussing particularly on the supply margin and any indications that investment signals are not working as expected, such as contract prices which are persistently above new supply costs or stalled investment plans.

Identify whether any reliability concerns are due to investment adequacy

Electricity systems can exhibit reliability concerns for a wide variety of reasons. This is true of systems with EOM and CM designs. Indeed, reliability concerns were around long before electricity markets were created in the 1990s.

If reliability concerns do emerge, it is important to identify the real source of those concerns. For example, reliability concerns may be unrelated to investment adequacy and the choice of market design.

This was the case with reliability concerns which emerged in the aftermath of the state-wide power cuts in South Australia. Those stemmed from tripping of wind generators following a power system disturbance. Adopting a CM would not have addressed that the concerns because they revolved around technical standards. Correctly diagnosing the concern is crucial to avoid solutions that are unnecessary, or worse, counterproductive.

Improve EOM design where feasible

If investment adequacy concerns do emerge, it would be important to understand whether they can be addressed without complete redesign of the electricity market. For example, adequacy concerns may be due to aspects of an EOM design that unintentionally cause problems – such as insufficient opportunity for DR to influence prices or poor price formation in scarcity situations. As the European Commission noted in November 2016, parties should first seek to "address their resource adequacy concerns through market reforms [..] no capacity mechanism should be a substitute for market reforms."[1] The European Commission made this statement because it was concerned that CMs could distort competition, risk jeopardising decarbonisation objectives and push up the price of electricity for consumers. [2]

Concerns may also arise for reasons that are temporary in nature and not directly related to the wholesale market design per se. This was the case with Germany which faced increased supply uncertainty due to the accelerated phase-out of nuclear power. After considering a wide range of options, Germany chose to retain an EOM design, but placed some generation in a temporary strategic reserve to facilitate the transition as nuclear plants phase out.

Understand the risks and costs of CMs relative to EOMs

Both EOMs and CMs have costs and risks – and there is no perfect option. If serious consideration is ever given to adopting a CM for New Zealand, it would be important to draw on the latest international experience.to understand the likely costs and risks. In this context, it is striking how much has changed among EOM and CM jurisdictions in the last five years. Whereas CMs were

[1] European Commission (2016), *Final Report of the Sector Inquiry on Capacity Mechanisms*, p.7
[2] Ibid, p.1.

previously thought to provide greater assurance on reliability than EOMs (albeit at a cost to consumers), that assessment is now open to question. More generally, policy makers worldwide are assessing how to adapt electricity market arrangements to facilitate the transition toward net zero carbon. One key question in this context is whether a rising proportion of intermittent generation will cause unacceptably high levels of spot price volatility, or whether participants will adapt via contracting and/or use of physical options such as batteries. Other countries are likely to strike these challenges before New Zealand, because our relatively large and flexible hydro generation base provides a cushion to ease the transition. This means that New Zealand should be able to benefit from the design experiences of other countries – and not repeat their mistakes.

Having said that, there are some critical issues where international experience is not very useful – simply because our issues are distinct such as exposure to drought risk (see chapter 6). New Zealand would need to develop its own assessment of costs and risks in relation to these issues.

2 Introduction

2.1 What this paper is about

Ever since wholesale electricity markets were established in the 1990s, there has been debate about the relative merits of the 'energy-only market' (EOM) design and the alternative 'capacity market' (CM) model.

> EOMs and CMs
>
> We use the term "energy only market" to refer to electricity markets in which the only assured revenue source for suppliers is spot market payments.
>
> We use the term "capacity market" to refer to the spectrum of mechanisms which create a regulated revenue stream that is distinct from spot market payments. These mechanisms include formal capacity markets, strategic reserves, and the firm energy market in Colombia. We use the term CM because it is commonly used in the literature to describe this family of mechanisms.
>
> See Chapter 3 for more information on the two alternative designs.

Proponents of EOMs argue they have lower costs for consumers and, if structured properly, can ensure reliable supply.[3] Supporters of CMs argue EOMs are prone to under-investment, and this must be corrected by adding a regulated market for capacity.[4]

Debate has intensified in recent years – particularly as nations accelerate their efforts to reduce greenhouse gas emissions. The debate has produced a burgeoning list of reports and developments including:

- ISO New England and PJM made substantial changes to their CMs after 2015 to improve operational performance (see section 4.5)
- The European Union competition authority conducted an inquiry into capacity mechanisms in 2016 because of concerns about their potential effect on competition (see section 5.3)
- Eastern Australia considered in 2016-17 whether to adopt a CM but chose to modify its EOM (see section 4.3.3)
- Britain suspended its capacity mechanism in 2018, after the European Court found it potentially breached competition rules (see section 4.2.3)
- A United States Federal Energy Regulatory Commissioner expressed serious doubts in 2019 about the effectiveness of current CMs (see section 5.4)
- Singapore is planning to replace its EOM with a CM from 2022 (see section 4.3.6)
- Alberta decided in 2014 to replace its EOM with a CM from 2021, and then abandoned that decision in July 2019 (see section 4.3.2).

This paper compares the two models – drawing on recent international experience and literature.

2.2 Structure of report

This report is structured as follows:

[3] For example, see Hogan, W. (2005) *On an "Energy Only" Electricity Market Design for Resource Adequacy*; Hogan, W. (2013). *Electricity Scarcity Pricing Through Operating Reserves*.
[4] For example, see Cramton, P. and Stoft, S. (2006). *The Convergence of Market Designs for Adequate Generating Capacity*; Cramton, P. *et al*. (2013). *Capacity Market Fundamentals*.

- Chapter 3 describes the key features of EOMs and CMs – focussing particularly on the latter as these are less familiar to readers in this part of the world
- Chapter 4 discusses the relative performance of EOMs and CMs in ensuring reliable power supply to consumers
- Chapter 5 discusses the relative performance of EOMs and CMs in relation to costs
- Chapter 6 outlines some issues specific to New Zealand that would need to be considered if a CM were to be adopted
- Chapter 7 sets out this report's overall conclusions.

3 Energy-only markets and capacity markets – what the heck are they?

This chapter describes what we mean by 'energy-only market' (EOM) and 'capacity market' (CM). This description focuses on the nuts and bolts of the two models and does not delve into their theoretical underpinnings.[5]

Readers already familiar with EOMs and CMs can skip to the next chapters, which discuss the relative merits of the two approaches.

3.1 Energy-only markets

New Zealand has utilised the EOM model since its wholesale electricity market was established in 1996. Other jurisdictions that use an EOM model include Alberta in Canada, states in eastern Australia, Denmark, Norway, Singapore, and Texas.

In jurisdictions with an EOM design, a generator's only assured revenue source is from electricity sales into the spot market.[6] In practice, generators may also earn revenue from forward contracts.[7] Indeed, these typically account for the majority of revenue received by generators. However, the volume of contract revenue is dependent on the risk preferences of buyers and sellers of contracts, and there is no regulatory requirement for consumers to enter into forward contracts with the EOM model.

Spot prices in EOMs

In any electricity system, there will be a small fraction of the total resource capability that is only needed very rarely - such as to respond to extreme demand peaks or provide cover during multiple power station outages. In the EOM design, when such last resort resources are operating, spot prices need to be able to rise to very high levels. This is because last resort resources may be entirely reliant on the revenue earned in those brief periods to cover their standing and operating costs.

In practice, last resort resource providers may be able to sell contracts as an alternative to relying on spot revenues – but buyers are unlikely to purchase such contracts unless there is a real potential for spot prices to be very high at times. Accordingly, in the EOM model, it is critical that spot prices can reach the value of lost load[8] during genuine scarcity situations.

Investment decisions are de-centralised in EOM

In an EOM, investment decisions in generation plant and demand-side response (DR) capability[9] are made by industry participants on a decentralised basis. A key factor affecting such decisions is the

[5] For readers interested in a more theoretical discussion of the models, a useful recent summary is contained in Bublitz A. *et al.* (2019), *A survey on electricity market design: Insights from theory and real-world implementations of capacity remuneration mechanisms*, Energy Economics 80: 1059–1078.

[6] Strictly speaking, generators may also receive regulated revenue from sale of ancillary services, but these are a relatively small proportion of total revenues and are not considered further in this paper.

[7] These can take many forms, including sales to end-consumers (possibly via a retail-arm of a vertically integrated firm), bilaterally negotiated hedge contracts, and trading of hedge products on exchanges.

[8] The value of lost load (VoLL) is intended to reflect the cost that consumers incur when they suffer unexpected power cuts. It is typically a very large value – estimated at around $10k-$20k per MWh in New Zealand.

[9] This refers to demand which can be altered by consumers (or agents acting on their behalf) in response to changing system conditions.

level of spot and contract prices. If parties expect a tightening supply margin, price expectations will rise, providing an incentive for more investment, and vice versa.

While the level of investment in generation and DR resources reflects decentralised decisions by participants, it is nonetheless influenced by regulators and market rules. Key design issues include spot price formation rules when security is reduced (such as lowered instantaneous reserve cover), the level of any price caps or floors in the spot market, and prudential security arrangements, since these can affect risk management trade-offs for participants.

3.2 Capacity markets

Jurisdictions that operate a CM include south western Australia, Colombia, and the schemes covering parts of the United States (the Mid-West ISO, ISO New England, New York ISO, and PJM market areas). A fuller list is included in Appendix A.

Some researchers argue that EOMs provide insufficient revenue to assure timely and adequate investment in resources. They say EOMs have 'missing money' because very high spot prices will not be tolerated during scarcity conditions and/or are explicitly capped at levels well below the value of lost load. To address the missing money problem, proponents of CMs say that investment/retention decisions must be incentivised by capacity payments which are separate from spot market revenues.

CMs take a wide variety of forms, but they all specify an explicit target level of capacity, and place physical or financial obligations on generators and consumers intended to achieve this target. The following sections describe key aspects of CMs in a little more detail.

Target level of capacity adequacy is determined by a central party

The main objective of CMs is to provide greater assurance there will be enough physical capacity in place to meet future demand, even in extreme conditions. This means that "enough" must be defined and specified as a target. This is typically done by a central party (such as a regulator or market operator). For example, a CM could specify a target that there is always enough generation and DR capacity installed to cover projected peak grid demand plus a (say) 15 percent safety buffer.

The central party will need to prepare estimates of projected grid demand, as these ultimately drive individual parties' purchase obligations. The methodology used by the central party needs to account for factors such as weather uncertainty, levels of self-generation by consumers, voluntary demand response, changes in consumption patterns, population growth, etc. The central party will need to gather a significant volume of information to develop these projections (some of which is commercially sensitive such as commissioning/closure dates for major industrial power users). However, ultimately the central party will be making guesses, and the consequences in terms of reliability and costs will be borne by consumers.

Obligations on retailers and other wholesale market purchasers

Once the overall capacity target is defined, it will be translated into specific obligations for retailers and other wholesale market purchasers, such as large industrial consumers. These parties will have an obligation to hold capacity rights[10] to match their assessed share of the overall system demand in defined timeframes. These rights can be from self-supply (if they have generation), or via purchasing rights from other parties.

Where parties need to purchase capacity rights, CMs may allow bilateral purchases or use a central buyer (e.g. PJM). Some CMs have a hybrid, where any deficit in bilaterally acquired rights must be

[10] We use the term 'capacity rights' in this paper, noting that some CMs seek to ensure the availability of firm *energy* rather than *capacity*.

topped up via purchases from a central buyer (e.g. the scheme in Western Australia). In all cases, the ultimate source of capacity rights is generators and DR providers.

Obligations on generators and DR providers

To provide assurance that the capacity being procured is real, the volume of rights generators and DR providers can sell is typically restricted or 'qualified' on an ex ante basis, so that volumes cannot exceed a provider's assessed firm capability. This assessment is normally overseen or undertaken by a regulator, which prescribes rules covering issues such as the treatment of fuel availability for thermal plants, derating factors for plant reliability, derating factors for intermittent generation, definitions of plant retirement and commissioning etc. This issue is discussed further in section 4.4.

Registry to track capacity rights

CMs need to set up some form of central registry to record the number of qualifying capacity rights available for sale by each generator, the number of rights that must be acquired or held by each wholesale purchaser (to match their assessed demand), and sales and purchases of rights between participants. The registry must also account for generation investments/retirements, and movements in consumers between parties due to retail competition.

Time horizon covered by capacity obligation

The obligation to purchase capacity rights will cover the current year at a minimum, and typically also extends for some future years as well. This provides more assurance that capacity will be installed when needed (noting the lead-time to build new generation is more than one year). Adopting a multi-year horizon provides a set of longer-term price signals, and may also provide generation and DR investors with greater revenue assurance.

However, the forward contracting obligation can pose challenges for parties whose demand is especially uncertain. For example, new entrant retailers or retailers losing market share can be penalised or advantaged, depending on specific rules adopted by the central party to allocate contract obligations among purchasers. Similarly, a large industrial user might face a contract purchase obligation some years into the future, despite uncertainty about its power demand in that year.

Commitment period

Sellers of capacity rights will be committed to provide capacity (and have rights to receive associated revenue) for a defined commitment period. This can vary from around a year to multiple years. Historically, CMs appear to have favoured one-year commitment periods. More recently, there seems to be a trend – at least for new generation – towards longer commitment periods under a fixed price with adjustments for inflation and a variety of conditions. For example:

- In PJM a single-year commitment period applies for capacity
- In ISO New England 1- or 5-year commitment periods apply for new capacity (generators have a choice) with capacity payments adjusted for inflation; there is a proposal to extend to 7 years
- In Great Britain, a 15-year commitment period applies for new capacity, 3 years for retrofits, and 1 year for existing generation.[11]

[11] Jenkin, T. Beiter, P. and Margolis, R. (2016). *Capacity payments in restructured markets under low and high penetration levels of renewable energy*. National Renewable Energy Laboratory, US Department of Energy.

Setting prices for capacity rights

An auction process is typically used to determine the price of capacity rights. To reduce auction price volatility and mitigate market power, these typically use a 'demand curve' approach (effectively price-quantity bids). The curve is typically anchored around a point representing the optimal capacity level and the assessed cost of new supply. A downward slope is applied so the capacity price falls with additional supply offers. A price cap is also typically applied. For example, PJM caps the price at around 150 percent of the assessed cost of new capacity, and the price falls to zero once capacity reaches 107.5 percent of assessed requirements.

CMs may seek to directly set the clearing price, and use this to 'steer' the volume of capacity on the system (e.g. Western Australia's CM did this in the past) – noting this provides more control over capacity prices but does not guarantee that optimal capacity level will be installed.[12]

Collecting the money to pay capacity providers

Depending on the design, capacity providers will receive payments directly from wholesale purchasers (retailers and grid-connected large consumers) or from the central party. In the latter case, the central party will collect contract payments from wholesale purchasers, and use it to pay capacity providers. In both cases, retailers will need to factor in their capacity payment obligations when setting prices for end-use customers. And irrespective of the particular design, consumers will ultimately bear the cost of capacity payments.

Capacity rights can be expressed in physical or financial terms

Capacity rights can be expressed in physical terms (e.g. rights to consume a given level of MW for a defined period) or financial terms (e.g. a hedge contract that protects the buyer from spot prices above a pre-defined level). Expressing rights in financial terms is more flexible and requires less prescription, but there is still a significant monitoring and enforcement issue.

Strategic reserves – a special form of CM

CMs can be subdivided into market-wide and targeted approaches. Market-wide mechanisms provide financial support to all capacity in the market, whereas targeted mechanisms directly support only a subset of capacity. Often, this is capacity intended to be used as a last resort if specific conditions are met, e.g., a shortage of capacity in the spot market or prices settling above a certain level. The cost of maintaining (and possibly running) this capacity is typically recovered from consumers via some form of uplift payment. We refer to these as strategic reserve schemes (noting that individual jurisdictions may have other names for them).

New Zealand had a scheme of this sort between 2004 and 2010. Sweden has a strategic reserve scheme, Britain introduced one in 2014, and Germany is planning a scheme to ease the transition as nuclear plant is decommissioned.[13]

One key issue with these schemes is that market participants may alter their private investment plans to take account of the presence of the strategic reserve – i.e. the aggregate system capacity may not increase with a strategic reserve. To counter this effect, policy makers may need to expand such schemes so that they become the principle revenue source for new capacity (as appears to be occurring in Great Britain) – in which case they become more like conventional CMs.

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[12] See European Commission, (2016). *Commission staff working document on the final report of the sector inquiry on capacity mechanisms: SWD(2016) 385 final*, available at https://ec.europa.eu/energy/sites/ener/files/documents/swd_2016_385_f1_other_staff_working_paper_en_v3_p1_870001.pdf.

[13] See https://europa.eu/rapid/press-release_IP-18-682_en.htm

In principle, strategic reserve schemes could be designed so they don't undermine private investment incentives – however it is very difficult to achieve in practice. This was one of the reasons New Zealand discontinued its reserve energy scheme in 2010. As noted in the 2009 electricity market review, the "the reserve energy scheme had a number of perverse effects and probably did not improve overall security of supply. Concerns were that the scheme:

- Reduces incentives on market participants to manage their own risks (because the EC is expected to manage those risks as a last resort)
- Reduces the incentive for investment in peaker plants and for demand-side responses (because Whirinaki's fixed costs are recovered by a levy on all consumers)
- Incentivises lobbying to change the rules relating to reserve energy (eg on despatch of Whirinaki and to contract for additional reserve capacity), creating uncertainty."[14]

In the balance of this report, we focus mainly on conventional CMs – noting that some observations are also applicable to strategic reserve schemes.

Spot market continues to exist

Jurisdictions with a CM still have a spot market, and this provides signals to guide short-term decisions, such as those relating to plant commitment and/or scheduling of discretionary demand by consumers. Because resource providers receive capacity payments, they are less reliant on the spot market for revenue. As a result, spot prices are generally lower on average and less volatile than in an equivalent EOM.

[14] Cabinet Paper (2009), *Ministerial Review of the Electricity Market*.

4 Reliability of supply

This chapter discusses the performance of CMs and EOMs in relation to the reliability of supply.

4.1 What do we mean by reliability?

The terms 'security' and 'reliability' can have different meanings, depending on the author and context. In this report, we adopt the definitions below, as they generally align with international usage. We note that 'security' is the term more commonly used in New Zealand.

Reliability

Reliability refers to having adequate generation and DR capacity[15] to continuously meet consumers' demand for electricity. Reliability can be quantified as the proportion of total electricity demand that is satisfied (or curtailed).

A secure power system is a necessary, but not sufficient, condition for reliability.

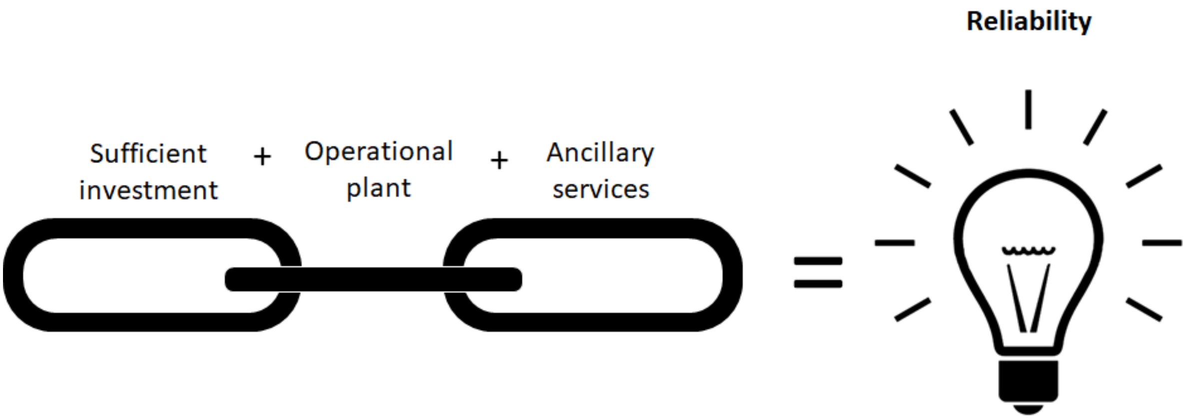
Security

Security refers to the ability of the power system to tolerate a disturbance (such as loss of a major generator or transmission circuit) and still maintain electricity supply to consumers. Security is achieved by operating the system in a stable state with instantaneous reserves available to counter unexpected events, and within the required bounds of technical parameters such as frequency, voltage, and fault current levels.

It is important to recognise that a chain of elements must work together to achieve reliable supply – as illustrated in Figure 1. As we discuss below, most CMs focus principally on the first element in the chain – ensuring sufficient generation or DR investment. Historically, this has been the issue of greatest concern to those who doubt the efficacy of EOM incentives.

While CMs contain elements to incentivise real-time operation, these have typically received less attention and there has been a reliance on real-time markets (spot or balancing) to incentivise operating decisions.

Figure 1: The reliability chain



[15] We include battery storage within the definitions of generation and DR.

4.2 How have CMs performed in terms of reliability?

We have not been able to identify any comprehensive study that assesses the performance of CMs from a reliability standpoint (ignoring outages caused by transmission or distribution level issues). Having said that, many studies seem to accept that CMs have generally met their *capacity targets*. For example, a 2014 survey of experts in the United States found:

> "the experts generally contend that the capacity markets have achieved the goals of providing the required reserve margin [..] (54% agreed, 23% disagreed, and 23% had no opinion)"[16].

However, achieving the target *capacity* does not necessarily ensure *reliability*. As we noted above, reliability for consumers requires a chain of elements to work together.

CMs typically focus on making sure there is sufficient generation or DR capacity installed in a system to meet peak demand. Less attention has historically been directed at ensuring these resources are actually available to consumers in scarcity situations. As Wolak (2004) noted, this is analogous to ensuring there are enough bakeries, rather than enough bread.[17] Wolak went on to state:

> "even if a wholesale electricity market has a capacity market, there is no way to compel generation unit owners provide electricity if they would prefer to withhold this capacity to drive up the spot price of energy [sic]. Recall the "sick day" problem that occurred with generation units during the period December 2000 to May 2001 when many units were "declared" unavailable to operate."

Similarly, Bushnell (2017) stated:[18]

> "Providing missing money alone does not ensure the adequacy or reliable supply, only the adequacy of generation capacity with the potential to provide reliable supply. But reliability is not enhanced if the "adequate" capacity is not operating when it is needed."

The potential for sizeable gaps to arise between installed and operational capacity, even in more 'mature' CMs, has been highlighted with experience over the last decade.

4.2.1 ISO New England

ISO New England serves consumers in six states in north eastern United States. In 2003, the ISO adopted a new market design which included a capacity market. In 2008, ISO New England held its first auction under the new capacity market. A review of the arrangements in 2012 identified that many units were failing to deliver the full capacity specified in their forward capacity market supply offers. Average underperformance was quantified as 40% of the additional power required by the System Operator during contingencies.[19]

The System Operator attributed this significant underperformance to the fact that:

> "capacity resources rarely face financial consequences for failing to perform, and therefore have little incentive to make investments to ensure that they can reliably provide what the region needs when supply is scarce."[20]

[16] Bhagwat, P. C. *et al.* (2016). *Expert survey on capacity markets in the US: Lessons for the EU*. Utilities Policy 38.
[17] Wolak, F. A. (2004). *What's wrong with capacity markets?* Stanford University.
[18] Bushnell, J. *et al*. (2017). *Capacity Markets at a crossroads*. UC Davis.
[19] Independent System Operator of New England (October 2012). *Forward Capacity Market Performance Incentives*.
[20] Federal Energy Regulatory Commission (May 2014). *Order on Tariff Filing and Instituting Section 206 Proceeding*. Docket no. ER14-1050-000-001.

Among the issues identified in the review were failures "to procure fuel, including natural gas-dependent resources during periods of limited gas supplies (particularly during the winter gas season), and the failure of resources to closely follow dispatch requests when needed to address contingencies".[21] The findings of the review prompted authorities to reassess arrangements (see below) – particularly those relating to operational incentives.

4.2.2 PJM

PJM is often considered to be a leader among markets with a CM. PJM serves over 65 million consumers. PJM's wholesale market was established on 1 January 1999.

In 2007, the market was redesigned to reflect incremental improvements and retail deregulation. The new design that became effective on 1 June 2007 included an annual capacity market, a forward market, locational capacity markets, scarcity pricing of capacity via a defined demand curve, clear links to the energy and ancillary services markets, incentives to provide energy reliability, and clear market power rules including a 'must offer' requirement. The redesign was regarded as a major improvement over the prior design.

In January 2014, the new design was tested when a polar vortex caused extremely low temperatures and record demand (141,846 MW) in the PJM region. During that weather event, PJM experienced an equivalent forced outage rate of 22%, far in excess of the 7% historical average. The capacity shortfall relative to obligations amounted to 40,200 MW. To manage this, system operators imposed voltage reductions of up to 5% but did not impose forced power cuts.[22]

While supply to consumers was not interrupted, the event was regarded a serious near miss and prompted authorities to reassess arrangements (see below) – particularly those relating to operational incentives.

4.2.3 Western Australia

To our knowledge, power supply in Western Australia has not been interrupted by generation adequacy concerns since a CM was introduced in 2005.[23] Having said that, in June 2008 an explosion at a gas production facility cut the state's gas supply by around 35 percent.

In the week after the event, State Premier Carpenter warned he might need to invoke emergency powers and take control of the state's gas and electricity supplies, which could result in rolling stoppages, blackouts and brownouts.[24] As it turned out, reliable electricity supply was maintained by drawing on alternative thermal fuel sources (including emergency supplies of diesel) and voluntary conservation measures.

4.2.4 Great Britain

Britain introduced a capacity mechanism in 2014. This involves an auction process, where bidders (existing and new generation and DR) compete to supply capacity in forward years via an auction process – the first of which was held in December 2014. While Britain has not experienced any major reliability issues, the capacity mechanism itself has not worked as intended. One key problem area has been the incentive regime.

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[21] Analysis Group (2013), *Assessment of the Impact of ISO-NE's Proposed Forward Capacity Market Performance Incentives*.
[22] PJM (August 2014)., *Problem Statement on PJM Capacity Performance Definition*.
[23] We note the authorities in Western Australia selected a CM as the preferred design in part because the system is small and there is a high degree of supplier concentration. A CM was thought to be better able to address incumbent market power and uncertainties associated with large lumpy loads.
[24] Megalogenis, G. and Tasker, S-J., *WA gas crisis poses threat to economy,* The Australian, 12 June 2008.

When the mechanism was designed, a penalty rate for non-delivery of 16,000 £/MWh was proposed. After negotiations with stakeholders, the penalty scheme was modified substantially and the charge was finally set at 1/24th of the respective auction clearing price, with a variety of caps on the penalties for CM contract holders. The reduced penalties meant that capacity prices were lower than expected in the first two auctions but according to some experts, it reduced the effectiveness of the performance incentive and undermined the integrity of the mechanism.[25]

In 2015, these researchers noted "if generators face little penalty for failing to deliver capacity, they may choose not to turn up in 2018"[26] (the first delivery period). This reasoning seems to have been confirmed by the indefinite delay in the construction of the 1.9-GW Trafford power plant, which was awarded capacity payments in 2014. Changes to the penalty regime were subsequently proposed to address the incentive issues.

In November 2018 the CM was suspended after the General Court of the European Union ruled that the European Commission had not effectively scrutinised the CM's competition implications. The ruling came after Tempus Energy challenged the UK Government arguing that the policy was anticompetitive.[27] In October 2019 the scheme was reinstated after the Commission confirmed that it complied with competition rules.[28]

4.2.5 Colombia

Most CMs are designed to meet a short period of scarcity (hours or days) caused by extremely high demand and/or multiple unexpected supplier outages. To our knowledge, the only CM which seeks to address reliability concerns over much longer periods (arising from hydro risk) is the scheme operating in Colombia. Like New Zealand, Colombia has a hydro-dominated system which is vulnerable in dry years. In such periods, reduced hydro generation must be offset by other actions, principally from higher thermal plant output.

In 2004, the regulator introduced a reliability mechanism in which suppliers sell firm energy obligations (Spanish initials = OEFs) via a centralised auction in exchange for fixed annual payments. These obligations are based on financial call option contracts with a high strike price and are backed by physical resources. When the spot market price exceeds the strike price, reliability providers are required to deliver the committed contribution and to return any positive difference between the spot price and the strike price to the contract buyer, receiving the option payment in exchange.

The regulator restricts the volume of OEFs that resource providers can sell. For hydropower plants, the allowable OEFs are calculated via an optimisation tool that assumes inflows will be at low levels. For thermal plants, OEFs are based on each plant's installed capacity, track record of forced outages and assessed fuel availability.

Colombia's scheme was tested by a drought in 2009/2010 and it did not work as expected. The regulator formed the view that hydro generators were not conserving water as intended and were instead generating to honour their overall bilateral sales commitments.[29] The regulator felt that if this pattern continued, it would result in very low reservoir levels at the beginning of the actual dry season. As a result, the regulator intervened, changing the dispatch rules to incentivise more thermal generation and reduced hydropower output.

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[25] Gammons S. and Anstey G. (2014). *The UK Energy Market Investigation: A Desperate Search for Evidence of a Lack of Competition?* Competition Policy International, 15 April 2014.
[26] Ibid.
[27] https://theenergyst.com/tempus-wins-european-court-case-capacity-market-bias-towards-generation-dsr/
[28] https://www.gov.uk/government/publications/capacity-market-reinstatement-letters-from-beis-to-national-grid-eso-and-esc-october-2019
[29] Comité de Seguimiento del Mercado Mayorista de Energia Eléctrica (July 2011). *Abastecimiento adecuado de gas natural: un tema sin resolver*. Report no. 60/2011.

Unexpected problems subsequently arose with some thermal plants due to fuel constraints. Despite holding firm gas supply contracts (necessary to be awarded OEFs), some thermal plants did not receive their contractually committed supplies. This was primarily due to unexpected pipeline capacity constraints. Some plants were capable of switching to liquid fuels, but the infrastructure for transporting liquid fuels had not been fully tested either, and supply problems arose in some cases. In total, of the 93 GWh per day of firm energy obligations contracted with thermal plants, 80 GWh per day were actually delivered.[30] Despite these setbacks, the Colombian electricity system managed to operate with no demand curtailment in the dry year.

After the event, performance during 2009/2010 attracted criticism from various quarters. The lower contribution from natural gas- and liquid fuel-fired plants revealed flaws in the methodology for awarding OEFs – especially in relation to the treatment of fuel supply risk. Similarly, hydro generators argued the regulator’s OEF methodology for hydro generation was flawed. They believed the regulator’s intervention denied them an opportunity to demonstrate an ability to generate above the level of OEFs they had been assigned.

The experience in Colombia illustrates the difficulties in measuring ‘firmness’ over extended periods – when factors such as fuel supply chain integrity, transmission network resilience and weather pattern uncertainty become much more important. It also shows the challenge this raises for a regulator, who may struggle to obtain the information and expertise to calculate each resource’s expected contribution in scarcity conditions.

The Colombian experience also highlights the importance of incentives for a regime to operate effectively. We understand Colombia’s scheme did not provide explicit penalties for underperformance. As noted above, contrary to the regulator’s expectations, hydropower plants continued to operate early in the dry year to meet their bilateral energy commitments, progressively draining their reservoirs. The Colombian Market Monitoring Committee concluded this was an indication that hydropower companies preferred the risk of future non-performance of their firm energy obligations over the immediate economic loss which they would have incurred had they reduced production and purchased power on the market to honour their bilateral contracts.[31]

An appropriate penalty regime may have altered the consequences of future non-compliance with OEF contracts, prompting hydropower companies to conserve more water to avoid potential charges in the future. Such an incentive might have also mitigated the fuel shortage-induced underperformance of thermal plants. The risk of paying a higher penalty might have encouraged thermal generators to sign fully firm fuel supply contracts, thereby motivating suppliers to reinforce the pipeline network, albeit also raising the overall cost of supply.

Despite some discussion of these issues in Colombia, we understand this type of approach has not been adopted, and the regulator CREG has institutionalised the interventionist approach applied in 2010 (i.e. it has retained some discretion over dispatch rules to limit hydro generation at times).[32]

As a recent World Bank (2019) review concluded, even though the Colombian regulator established a mechanism with the explicit goal of ensuring reliable supply, it has not achieved this goal.[33]

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[30] Ibid.

[31] Comité de Seguimiento del Mercado Mayorista de Energia Eléctrica (October 2010). *Experiencias de la intervención del MEM bajo efecto del Niño 2009–10*. Report no. 53/2010.

[32] Comisión de Regulación de Energia y Gas (March 2014). *Resolución 26 de 2014, Por la cual se establece el Estatuto para Situaciones de Riesgo de Desabastecimiento en el Mercado Mayorista de Energia como parte del Reglamento de Operación*. Resolution from the Regulator.

[33] Rudnick, H. and Velásquez, C. (2019). *Learning from Developing Country Power Market Experiences - The Case of Colombia*, World Bank Group Energy and Extractives Global Practice March 2019: 52.

4.3 Are EOMs any better in relation to reliability outcomes?

As with CMs, we are not aware of any study that assesses the reliability performance of EOM in a comprehensive manner. Instead, we briefly review below the performance of the major EOMs in relation to reliability.

4.3.1 New Zealand

New Zealand has operated an EOM design since the market was established in 1996. Although widespread forced load-shedding has never been required, public conservation campaigns were instituted to offset the effect of reduced hydro-generation during droughts in 2001, 2003 and 2008.

The frequent use of such measures led to changes in 2009 designed to reduce the perceived over-reliance on public conservation campaigns and improve reliability. Since those measures were adopted, no public conservation campaigns have been triggered. This is despite a severe drought in 2012 and droughts in 2017 and 2018.

More generally, New Zealand's capacity and energy margins have been actively monitored by the regulator or system operator for many years. Since that monitoring was introduced, the margin for the coming year has not dropped below the level assessed as being economically optimal. Indeed, at times it has been appreciably above that level.[34]

Having said that, New Zealand's supply margin increased appreciably for a period after 2009. This occurred as new generation investments committed earlier came on stream and demand was flat following the Global Financial Crisis. This makes it harder to determine whether performance since 2009 is due to the changes in market rules or the wider supply margin.

4.3.2 Alberta

Alberta has had an EOM design since its wholesale electricity market was formed in 1996. As far as we are aware, it operated reliably until July 2013, when there were forced power cuts as high demand coincided with outages at six generators.[35]

In 2016 the system operator launched a review because of growing concerns about the adequacy of investment incentives – particularly in the transition to much higher renewable generation sources. The system operator's review culminated in a 2017 provincial government decision to adopt a CM design from 2021.

Following an election in 2019, the incoming government reviewed the planned CM introduction. It concluded the EOM design was better able to address investment incentives than a CM and would have lower costs. In July 2019 the government decided to retain an EOM design.[36]

4.3.3 Eastern Australia

The eastern states of Australia have utilised an EOM design since inception of the so-called National Electricity Market (NEM) in the late 1990s. Until recently, the NEM has generally been regarded as performing well on the reliability front. However, in recent years there have been growing concerns about tightening capacity margins as older thermal plants retire. Concerns have also been expressed about the challenges associated with a rising share of generation from intermittent renewable sources.

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[34] See https://www.transpower.co.nz/system-operator/security-supply/security-supply-annual-assessment

[35] www.cbc.ca/news/canada/edmonton/alberta-hit-by-rolling-power-blackouts-1.1178711

[36] https://edmontonjournal.com/news/politics/conditions-have-changed-government-kills-planned-changes-to-albertas-electricity-market

In 2016, the NEM experienced widespread power outages when supply was cut to most consumers in the state of South Australia. The initial cause was a storm which knocked out some transmission towers and lines. Supply was then reduced further by the tripping of some wind generators which did not 'ride-through' the fault conditions when the transmission circuits were lost. The reduction in wind generation output then triggered a cascade failure in the South Australia region. Court cases are currently being pursued by the Australian Energy Regulator against the operators of the relevant wind farms alleging failure to perform in accordance with technical standards.

In response to this event and broader concerns about the potential for a messy decarbonisation transition, the NEM's market back-stop arrangement was recently modified. Until 30 June 2019, the NEM rules included a Reliability and Emergency Reserve Trader (RERT) mechanism. In essence, this mechanism allowed the market operator to procure last resort resource (such as DR) if it believed that forced load shedding would otherwise be required in the near term (e.g. the coming summer). The RERT mechanism included cost recovery arrangements designed to avoid suppression of spot price signals, if the mechanism was triggered.

The RERT mechanism was augmented from 1 July 2019 with an additional Retailer Reliability Obligation (RRO) which looks beyond the near-term.[37] The RRO mechanism allows the regulator to trigger an obligation on retailers and other wholesale purchasers to hold qualifying contracts (or generation rights) for their share of projected peak demand, if the regulator (on advice from the market operator) identifies a reliability gap in the three year outlook. If a reliability gap still remains in the forecast with 15 months to run, the regulator (again on advice from the market operator) can trigger a tender to acquire resource to fill the gap (such as contracted DR) – similar to the pre-existing RERT mechanism. The cost of acquiring such resources is to be recovered from any retailers/purchasers with insufficient contracts/generation to cover their assessed peak demand, with costs per party capped at A$100 million.

The revised back-stop arrangement has some features which are CM-like. In particular, a requirement for purchasers to hold contracts or generation rights on a forward basis is a hallmark of CMs. However, it is important to note the requirement in the NEM does not apply unless the regulator (acting on advice) makes a specific RRO determination. If such a determination were to be made, it would apply only to specified regions and time periods. Thus, the default position in the NEM continues to be an EOM design with participants determining their contract positions, albeit in the knowledge that an RRO might be triggered at some point.

When the RRO was being developed, the possibility of introducing a full-blown capacity mechanism was also raised.[38] However, authorities chose to retain an EOM design with a stronger market backstop. More generally, there is a fairly broad view that better integrating emissions and electricity policy (at both the national and state levels) should be given more priority.[39]

Finally, there is a growing focus on the need to strengthen real-time incentives and the design of ancillary services markets. For example, the retirement of large synchronous units has introduced security challenges relating to inertia and system strength.[40] These are currently addressed by interventions by the market operator but are increasingly prompting discussion about longer-term solutions. These lines of thinking are well summarised in a 2018 study published by the Oxford Institute for Energy Studies, which argued that consideration should be given to extending the energy-only design to an 'energy+services' model, in which efficient price signals are created for the

[37] See www.energy.gov.au/sites/default/files/retailer_reliability_obligation_factsheet.pdf.
[38] For example, see: Wood, T. *et al.* (2017). *Next Generation: the long-term future of the National Electricity Market*. Grattan Institute.
[39] https://www.aemc.gov.au/news-centre/economists-corner/profiling-capacity-market-debate
[40] System strength is an umbrella term that reflects the ability of the power system to maintain stability after a disturbance. System strength is a highly localized issue and varies across parts of networks.

missing products necessary for operational security.[41] Strictly speaking, the NEM (and New Zealand for that matter) already operate an energy+ services model, and this proposal can be viewed as enhancing the range of ancillary services procured in parallel with energy.

4.3.4 Western Australia

Western Australia implemented a Capacity Market since 2012 and since that time has maintained a high level of supply reliability. In January 2020, however, unplanned generation outages caused 98,000 customers to suffer blackouts, (around 7.5 percent of total connections). Power was restored to most customers within an hour[42].

4.3.5 Nord Pool

Nord Pool has operated an energy-only trading system for many years, covering Norway, Denmark, Sweden, Finland and part of northern Germany.[43] As far as we are aware, it has operated without any major capacity adequacy problems.

4.3.6 Singapore

Singapore's electricity market has utilised an EOM model since it was created in 2001. Singapore has experienced extremely high levels of reliability for most of this time. However, in September 2018, power cuts affected 147,000 consumers when two power stations tripped unexpectedly.[44] We note this event was not due to inadequate generation resources – Singapore's peak demand is around 7,000 MW and the island's installed capacity is approximately 13,500 MW.[45]

Notwithstanding the current supply margin, Singapore's authorities have become concerned about the outlook for future investment adequacy. This appears to stem from a combination of current low prices and the authorities' desire to maintain at least a 30 per cent reserve margin of non-intermittent plant above peak demand. While this appears to be viewed as politically necessary, it is likely to be well above an economic optimum or what an energy-only market would deliver over the longer-term.

In mid-2019, the regulator released a high level straw proposal for a capacity market for Singapore. The proposed design would introduce a CM from 2022, with transitional arrangements to apply from 2020. Capacity would be procured over a four-year forward horizon, with resource providers selected via an auction mechanism. Resources would be subject to a qualification process to validate their availability in the delivery year, as well as the megawatt ("MW") value they may offer into the forward capacity market auction.

Each MW-year of capacity offer would require that MW of qualified capacity to be available, and to offer into the energy market, for a year, subject to penalties for failing to perform. The penalty rates would "be high enough to incentivise performance (but not so high as to impose undue costs that discourage participation)". Supplier offers into the spot market would be capped at short-run marginal cost for the supplier.[46]

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[41] Billimoria, F. and Poudineh, R. (2018). *Decarbonized market design: an insurance overlay on energy-only electricity markets*. Oxford Institute for Energy Studies.
[42] https://www.aemo.com.au/news/south-west-interconnect-system-power-event-10-january-2020
[43] We note Sweden has had a strategic reserve scheme since 2003, and Germany is planning to introduce one.
[44] See www.tnp.sg/news/singapore/worst-blackout-14-years-hits-147000-households-and-businesses
[45] www.energycouncil.com.au/analysis/singapore-some-familiar-issues-in-an-unfamiliar-context/
[46] See www.ema.gov.sg/cmsmedia/Consultation%20Paper%20-%20Developing%20a%20FCM%20to%20enhance%20the%20SWEM.pdf

The regulator released a second consultation paper for developing a forward capacity market and sought submissions by January 2020. It is currently considering those submissions.[47]

4.3.7 Texas

Within the United States, Texas is the only state with an EOM design.

The market operator (ERCOT)[48] implemented widespread forced load shedding in 2011 when a polar vortex caused record low temperatures. This lifted demand and caused outages (e.g. from freezing pipes) at some generation plants.[49] In the subsequent polar vortex event in 2014, ERCOT (like PJM) experienced very high demand but did not need to implement load shedding.

More recently in August 2019 ERCOT declared an Energy Emergency Alert as reserve dropped below 2,300 MW[50]. This was the result of forced outages and unusually low wind production.

4.4 Operational incentives are important for EOMs and CMs

Experience with both EOMs and CMs has highlighted the importance of operational incentives – i.e. the incentives to make resources available and to utilise them in scarcity conditions.

4.4.1 Operational incentives should be robust with EOMs

In the case of EOMs, the prices generated in the spot market should (and typically do) provide very robust incentives to make resources available. Furthermore, the spot price signal is visible to all resource providers – both supply-side and demand-side and is unaffected by a participants' net contract position. As a result, during scarcity conditions, there will be very strong and uniform signals to all wholesale participants to increase supply and voluntarily reduce demand.

Having said that, an EOM's operational signals may be undermined by other aspects of an electricity market design, such as weak prudential arrangements or unduly low price caps. In essence, EOMs will be less effective (and possibly fail) if participants can socialise the costs from poor decisions. A similar set of concerns applies in the banking sector, where regulators want to ensure banks cannot shift the cost of any poor decisions to other parties. In principle, such concerns can be addressed by measures such as robust prudential and stress-testing regimes.

4.4.2 Operational incentives with EOMs have been mixed

Experience with operational incentives in CMs has been mixed. The record of ISO New England, PJM and Colombia all point to difficulty in ensuring resource providers will deliver their promised level of firm capacity. With CMs, this challenge arises because resource providers earn revenue from the sale of capacity rights, but it is inherently difficult to detect any non-performance because the full capacity obligation is rarely called upon.

In practice, two broad approaches have been used to deter non-performance in CMs:

1. Allowing resource providers to self-declare their level of firm capacity – and applying stiff financial penalties for non-performance. In principle, these should reflect the economic cost of non-performance (noting this can range up to the value of lost load in a scarcity event).
2. Assessing the maximum physical capacity of each provider and restricting their sales to this level. The capacity determination methodology needs to consider many detailed issues, such

[47] See www.ema.gov.sg/cmsmedia/Second%20Consultation%20Paper%20-%20Developing%20a%20FCM%20to%20Enhance%20the%20SWEM.pdf
[48] Electricity Reliability Council of Texas.
[49] See https://rbnenergy.com/the-night-the-lights-almost-went-out-in-texas-polar-vortex-power-markets
[50] https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/081519-ercot-declares-another-energy-emergency-alert-prices-hit-9000-mwh

as the provider's access to firm fuel supply, level of plant reliability, adjustments for plant intermittency, degree of firm demand response etc. This is inherently difficult – especially where conditions are changing – such as when fuel supply conditions change. Penalties apply for any non-performance relative to assigned capacity, but these are normally well below the economic cost level.

As Batlle *et al*. point out, in theory resource providers are best qualified to estimate the expected capacity contribution from their facilities in scarcity conditions. And provided robust penalties apply (including financial performance guarantees), there should be no need for regulatory limits on the amounts of capacity that they sell.[51]

However, in practice most CMs make the regulator the arbiter of capacity, reflecting a mistrust of resource providers and the associated fear of power shortages. As one researcher noted "system planners and engineers have been uncomfortable with what they perceive as a reliance on purely financial, rather than physical, resource plans" with a strong preference for ensuring there is "steel in the ground".[52]

4.5 Penalties for operational non-performance are being revisited in CMs

There has been a trend to refine the penalties for operational non-performance in CMs. This has arisen in response to recent experience (such as the polar vortex event in the United States) and to prepare for higher levels of intermittent generation – since these will create new types of reliability challenge.

Bublitz (2019) notes that refining the level of penalties requires careful balancing. Penalties should be high enough to ensure providers deliver on their commitments, but not so high that risks and costs for providers are unduly raised – since that will ultimately harm consumers.[53]

In ISO New England, the System Operator has established a higher penalty regime which is based on the assessed revenue requirement for a last resort supplier. The penalty rate is being progressively increased to US$5,455/MWh, which will apply from 2024 onwards.[54] We understand that this rate is based on the expected cost of a new entrant provider (based on CCGT technology), divided by the expected number of hours of scarcity conditions if the target reliability standard is met, adjusted by the expected performance during scarcity conditions (US$106,394/MW-year / (21.2 hours/year x 0.92) = $5,455/MWh).

From 1 June 2016, PJM began implementing new rules designed to better ensure resources will be available when called upon, especially in extreme weather conditions.[55] Under the new rules, resource providers assume greater financial risks if they do not meet their power supply obligations. The new rules are being progressively phased-in with full delivery from the capacity year 2020–21. We understand the penalty rate for scarcity conditions in PJM's revised regime is also based on the cost for a new entrant last resort provider.

An interesting aspect of the revised approaches being taken by PJM and ISO New England is that they have some strong parallels with energy-only markets. In EOMs, parties who sell firm capacity

[51] Batlle, C., *et al.* (2015). *The System Adequacy Problem: Lessons Learned from the American Continent*. Capacity Mechanisms in the EU Energy Markets: Law, Policy, and Economics, London, UK: Oxford University Press.

[52] Bushnell, J. *et al.* (2017). *Capacity Markets at a Crossroads*. Berkeley, Energy Institute at Haas working paper.

[53] Bublitz A., *et al.* (2019). *A survey on electricity market design: Insights from theory and real-world implementations of capacity remuneration mechanisms*. Energy Economics 80.

[54] Federal Energy Regulatory Commission (May 2014). *Order on Tariff Filing and Instituting Section 206 Proceeding*. Docket No. ER14-1050-000.

[55] PJM Interconnection (2018). *Strengthening Reliability: An Analysis of Capacity Performance*.

but fail to generate are exposed to the spot price. And in a scarcity situation, the spot price may reach the market price cap, which is typically set by reference to the revenue requirement for a last resort provider. Indeed, that is the approach taken in Australia, New Zealand[56] and Singapore. In effect, it appears that some aspects of CM designs (at least for PJM and ISO New England) are converging towards the features of an EOM.

Yet, it is important to note that penalties associated with a capacity contract can only mimic the spot price in inducing efficient behaviours. This is because a CM penalty will often need to be set in advance, rather than to reflect conditions at the time non-performance occurs. Furthermore, in a CM, penalties for non-performance will not be signalled to all resources, but only to those taking part in the capacity mechanism.

In this context, it is important to recall that providers only take on an obligation (and exposure to penalties) if their offer was accepted in a prior auction. There will typically be other physical resources not subject to any capacity obligation which could assist in an emergency. These can include resources such as stand-by generation on customers' premises, emergency DR capability, or additional capacity at power stations that were not cleared in previous capacity auctions.

Resource providers who are not obligated under the capacity mechanism may be able to assist in meeting demand, but will not receive a strong signal to do so because spot prices in a CM are typically set below the economic value of supply (unlike in an EOM).

Some commentators have gone further and suggested that improving the operational incentives of CMs will always be a second-best approach. For example, Professor Hogan stated:

> "everything channelled through the capacity market is indirect and convoluted. The process almost seems driven by a commitment not to fix the actual energy markets prices but rather to find ever new and ever more indirect pathways to reproduce the results of an efficient real-time market without actually implementing an efficient real-time market."[57]

4.6 Conclusion in relation to reliability

CMs provide a high level of assurance that sufficient generation and DR will be *built.* This is because CMs create explicit commitments to invest in supply capability. CMs can also include tests to ensure that parties' commitments are backed by 'steel in the ground'. Having said that, many EOMs (e.g. New Zealand, Nord Pool, Singapore) have performed well in ensuring sufficient capacity is *built*.

So, the real difference between CMs and EOMs is the level of ex ante assurance they provide. CMs provide a higher degree of assurance about the level of *built* capacity because that variable is under the direct influence of the regulator/market operator. However, the centralisation reduces the scope for testing of different views and increases dependence on a few decision-makers.

Turning to operational issues, CMs do not provide assurance that resources which have been *built* will actually be *available* when required. Indeed, experience to date suggests that EOMs will almost certainly perform better than CMs on this front, because EOM spot prices create stronger signals to make all resources available during periods of scarcity.

Given these factors, the overall assessment of the two designs on reliability is not clear-cut and depends in large part on what policy makers are most worried about – ex ante assurance about the level of *built* capacity, or that resources which have been built will be *available* when required.

[56] New Zealand currently applies both a floor and a cap in scarcity situations involving widespread forced load shedding. In effect, the floor is based on the assessed costs for a new entrant last resort provider, and the cap is based on an estimate of the average value of lost load.
[57] Hogan, W. (2014). *Electricity Market Design and Efficient Pricing: Applications for New England and Beyond*. The Electricity Journal 27(7): 23–49.

5 Costs to consumers

This chapter considers the relative performance of EOMs and CMs in relation to costs.

5.1 CMs are prone to over-investment

CMs are prone to encouraging over-investment. The core reason is that CMs require a central party to make most of the key decisions – and it is very difficult to align the incentives of the central party with those of the consumers they represent.

One of the most important decisions is the overall reliability standard itself – which provides the anchor for the entire CM. Equally, if not more important, the central party will face a host of ongoing decisions to put the CM into operation, such as compiling demand projections, determining derating factors for generation, etc.[58]

One of the most important decisions is the level of voluntary demand response to assume during periods of tight supply, when spot prices will be higher. If the central party under-estimates the level of voluntary response, it will force some buyers to incur unnecessary costs for contracts that are not needed. Conversely, if it over-estimates the level of voluntary demand response in its projections, insufficient resources will be procured to meet the target capacity standard.

In making the big and small decisions, the central party will be aware that the cost of underinvestment will be very visible in the form of power cuts, whereas the cost of over-investment is difficult if not impossible to measure with certainty. Many researchers argue that this leads to skewed incentives and a strong tendency towards over-investment – to the detriment of consumer costs and efficiency.[59] International experience supports this view.

Western Australia

A review of the CM in Western Australia concluded the "primary problem with the mechanism was that it was leading to a significant over-procurement of capacity [..] with the level of excess capacity over the market requirement reaching 23 per cent by 2016-17 at an estimated cost of around $116 million."[60] This is an annual figure, and such costs were borne by the approximately 1.1 million households and businesses covered by that CM. Part of the cost arose from that CM's specific design, but it was also affected by the implementation challenges such mechanisms.

Figure 2 shows actual peak demand depicted by the dotted line at the bottom of the chart. The figure also shows various demand forecasts compiled in successive years, expressed on a 10% probability of exceedance (POE) basis.

The lines show that strong demand growth was expected for much of the period, driven by rising residential demand and rapid industrial expansion associated with the minerals boom prior to the global financial crisis (GFC). Conditions changed part way through the period, with strong uptake of roof-top solar panels (cutting residential demand) and the tapering off of industrial growth post-GFC. It took some time for these changes to become fully apparent, resulting in a widening gap between

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[58] As noted in the previous chapter, it is also possible the CM will lift capacity without necessarily improving reliability.

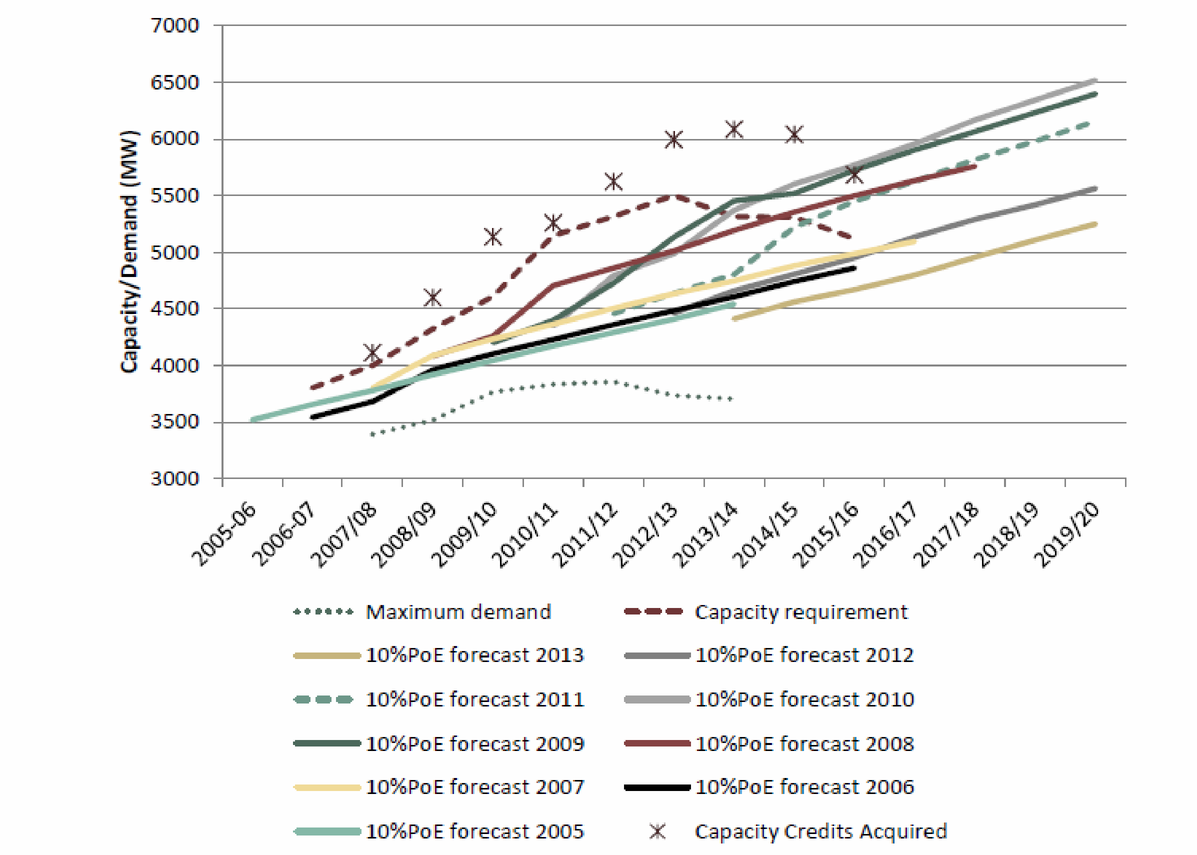
[59] See: Wood, T. *et al. Down to the wire: A sustainable electricity network for Australia* (Technical Supplement), Grattan Institute; Wood, T. and Blowers, D. (2017). *The Long Term Future of the National Electricity Market*, Grattan Institute; Grubb, M. and Newbery, D. (2015). *Security of supply, the role of interconnectors and option values: insights from the GB capacity auction*, Economics of Energy & Environmental Policy 4, 2: 65-82.

[60] Government of Western Australia, Department of Treasury, Public Utilities Office (February 2019). *Improving Reserve Capacity pricing signals – a recommended capacity pricing model Final Recommendations Report.*

forecast and actual demand in the period after 2009. Subsequently, the gap narrowed as demand forecasts were scaled back significantly.

Because of the way the mechanism worked in Western Australia, there was substantial over-procurement of capacity. This was partly due to the forecasting challenges, but also because capacity prices were not closely linked to market need. As a result, in 2013/14 more than 6,000 MW of capacity was procured (and paid for), compared to peak demand of less than 3,750MW..

Figure 2: Historical demand forecasts compared to actual demand



Source: Electricity Market Review Discussion Paper, Electricity Market Review Steering Committee, Public Utilities Office, Western Australia, July 2014

As the review author's noted: "the weakness of the [CM] lies not in the forecasting ability of the [market operator], as this is likely to be no better or worse than other forecasting efforts undertaken over the same period, but in the use of a process so prone to error and over-estimation to determine such a large proportion of electricity costs. The costs of over-investment are not borne by the investors themselves, as they would be in the NEM and in most commodity markets, but by customers".[61]

[61] Government of Western Australia, Department of Treasury, Public Utilities Office (2014). *Electricity Market Review Discussion Paper*.

United States

Other sources cite over-investment as a common concern. For example, Wolak (2004) states "capacity payments encourage over-investment and new generation capacity mix that [is] more expensive [than] is necessary to meet an increase in annual electricity demand."[62]

Bhagwat (2016) undertook a survey of experts in the United States and reported "the experts generally contend that the capacity markets have achieved the goals of providing the required reserve margin, but in an economically inefficient way [and] these costs appear to be mainly due to a higher reserve margin than would be economically optimal".[63]

Even energy regulators have expressed concerns about over-investment with CMs. In April 2019, in a dissenting opinion, one of the United States Federal Energy Regulatory Commission's (FERC) three commissioners stated:[64]

> "[Arrangements cause] PJM to procure too many resources at too high a price, with obvious detrimental consequences for consumers."

Germany

Germany has utilised the EOM model. It carried out a review in 2014/15 because of potential reliability concerns arising from its plans to aggressively move away from fossil fuel and nuclear-powered generation. The review considered a range of options including enhancements to the EOM model, strategic reserves and traditional CMs covering the procurement of all capacity.

A traditional capacity market design was rejected on the basis of three primary reasons: 1) sufficient levels of existing capacity, 2) a general perception that capacity markets distort the market, and 3) cost effectiveness.

In particular, the main research report for the review noted a "central capacity tendering mechanism with reliability contracts .. and the focused capacity mechanism .. bear the risks of considerable overcapacities. The latter is due to the fact that regulatory authority/administrations can be expected to aim at rather high capacity levels due to the high risk aversion."[65]

The German government white paper rejected a capacity market. Instead, it proposed the energy-only market be enhanced, and that a temporary strategic capacity reserve be kept in place, particularly to ease the phase-out of nuclear plants. This reserve was subsequently approved by EU competition authorities as a transitional mechanism.[66]

5.2 CMs more likely to distort resource mix

Another concern with CMs is their potential to bias resource mix decisions (including DR) and raise supply costs. For example, Wolak (2004) stated capacity payments encourage a "generation capacity mix that is more expensive than is necessary to meet an increase in annual electricity demand." Grubb and Newbery (2015) believed insufficient attention has been paid to the importance of capacity characteristics, and that this neglect biases decisions "towards over-procurement, which leads to a self-fulfilling prophecy that merchant generation investment can no longer be relied upon.

[62] Wolak, F. (2004). *What's Wrong With Capacity Markets?* Stanford University.

[63] Bhagwat, P. C. *et al.* (2016). *Expert survey on capacity markets in the US: Lessons for the EU*. Utilities Policy 38.

[64] Glick, R., United States of America Federal Energy Regulatory Commission, dissenting opinion on dockets ER19-105-001 and ER19-105-002, April 2019.

[65] Frontier Economics and Consentec (2014). *Impact Assessment of Capacity Mechanisms.* Report for Federal Ministry for the Economic Affairs and Energy.

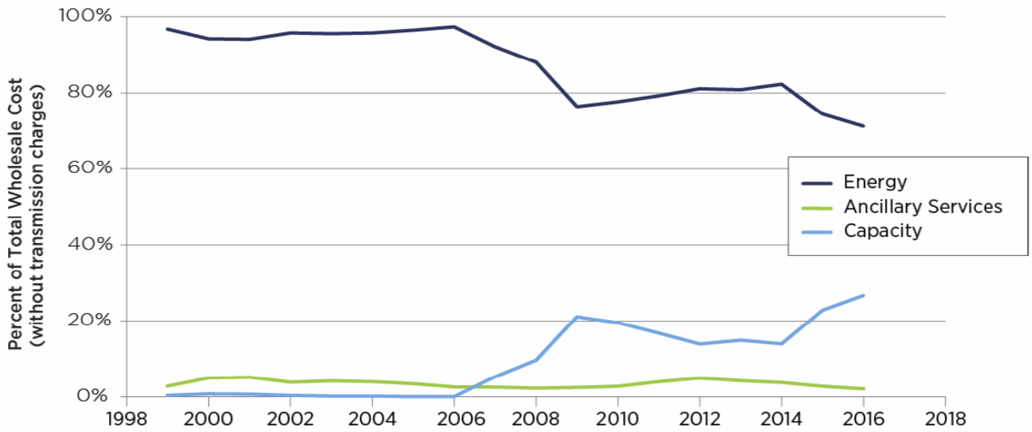
[66] See https://europa.eu/rapid/press-release_IP-18-682_en.htm

Perversely, this exacerbates the missing money problem that capacity auctions were designed to address."

FERC Commissioner Richard Glick (2019) noted that by encouraging over-investment in capacity, PJM's CM reduces prices in the energy spot and ancillary services markets. He said this exacerbates the missing money issue, increasing reliance on CM revenues, and distorting the investment mix..[67]

PJM (2017) itself has also expressed concerns about the potential for distorted incentives. In filings to FERC, PJM noted a rising share of revenues coming from CM payments (shown in Figure 3), and commented that increasing reliance on these payments may unduly alter the resource mix.

Figure 3: Share of total wholesale electricity costs



Source: PJM (June 2017), *Energy Price Formation and Valuing Flexibility*.

A related issue is that where CMs adopt prescriptive approaches to determine firmness (rather than using spot prices as incentives), this can create unintended biases in favour of some resource types relative to others. For example, a CM will need to assign 'firmness factors' to wind generators – i.e. the volume of output that will be assumed to be firmly available in scarcity conditions. This will affect capacity payments that wind generators can receive, and may bias wind generation investment up or down, depending on the methodology used by the regulator.

Finally, a CM may bias the resource mix by treating resources in different ways based on their source, rather than any difference in inherent performance. For example, under the British capacity mechanism, existing power plants can get contracts for one year, or three years, if they carry out upgrades. New power plants can get 15-year deals. And DR is only offered one-year contracts. This difference means the mechanism may not necessarily select the lowest cost option and was part of the basis of a successful legal challenge to block further auctions, discussed in section 5.4.

5.3 Competition and market power

Electricity is expensive to store, and most consumers are reluctant to voluntarily reduce their demand below planned levels. In combination, these factors mean spot prices are likely to reach very high levels if they are to send the appropriate economic signal during scarcity conditions. However, in such situations, it can be difficult to determine whether high prices are fully justified as suppliers can have more ability and incentive to raise spot prices (depending on their contract position). This means that EOMs need robust mechanisms to ensure there is competition in the spot and contracts markets (such as information disclosure rules and market-making arrangements).

[67] Glick, R., United States of America Federal Energy Regulatory Commission, dissenting opinion on dockets ER19-105-001 and ER19-105-002, April 2019.

One of the benefits often cited for CMs is that they mitigate suppliers' market power in scarcity conditions, because they reduce providers' reliance on spot market revenues and hence facilitate the adoption of lower price caps. Similarly, if a CM is structured as financial contracts which wholesale buyers must acquire, purchasers will be largely insulated from spot prices and caps can be set at high levels to maximise operational incentives.

While CMs can mitigate market power in relation to the spot market, they do not address all competition issues. International experience shows competition concerns often arise in the capacity market itself – on the seller or buyer side of the market. As noted by Brattle (advising the Singapore government on a possible CM) "market power is endemic to capacity markets (and to energy markets during tight supply conditions) because available supply typically exceeds demand by small margins, such that even medium-sized suppliers could withhold capacity profitably, unless required to offer competitively."[68]

Seller market power is also enhanced by the fact that most CMs compel buyers to hold a minimum level of capacity rights by prescribed dates – constraining some of the countervailing power buyers would otherwise have. Furthermore, the competitive dynamics in a CM auction can be difficult to predict at the time rules are being set, noting these may be finalised well before the auction to give prospective new bidders time to develop investment plans.

Concerns about market power are borne out by experience. For example, the recent World Bank (2019)[69] review of Colombia's CM noted that the mixed results of the scheme were due in part to "insufficient competition in auctions".

Similarly, the independent market monitor for ISO-New England stated:

> "when new suppliers are pivotal (must clear in order for ISO-NE to satisfy its capacity requirements) … they have strong incentives to raise their offers and increase the capacity prices. .. Likewise, the report shows that existing suppliers that are pivotal have strong incentives to retire units that would otherwise be economic in order to increase capacity prices."[70]

The American Public Power Association has raised potential concerns about existing generators discouraging new entry to ensure higher energy prices while receiving capacity payments, noting that "owners of existing generation resources have a strong interest in the current regime, which prevents competition from new entrants and props up capacity prices."[71]

One of the most common ways to address market power has been to impose caps and/or floors on auction prices for capacity. As noted by Bublitz et al. (2018):

> "the upper price cap needs to be high enough to incentivize sufficient investments when the system is tight and typically equals a multiple of the Net CONE [cost of new entry]. The lower price cap is usually set equal to zero and marks the capacity level when the desired reserve margin is reached. However, sometimes, in order to avoid a total price collapse or prevent

[68] See www.ema.gov.sg/cmsmedia/Annex%20A%20-%20High-Level%20Design%20Straw%20Proposal%20v1.pdf

[69] Rudnick H. and Velásquez, C. (2019). *Learning from Developing Country Power Market Experiences The Case of Colombia*. World Bank Group Energy and Extractives Global Practice: 52.

[70] Patton, D.B., et al. (2014). *2013 Assessment of the ISO New England Electricity Markets, External Market Monitor for ISO New England,* Potomac Economics.

[71] American Public Power Association, *RTO Capacity Markets and their Impacts on Consumers and Public Power,* APPA Fact Sheet, May 2015.

> market manipulation from large purchasers of capacity, a higher price is set, e.g., 75% of the Net CONE. [..] when setting the upper and lower price limit".[72]

Indeed, some commentators are unconvinced that bidding rules in CMs can effectively address market power and believe more direct measures are required. For example, Wolak (2004) stated CMs are "extremely susceptible to the exercise of unilateral market power, which implies that regulatory intervention is often needed to set the price paid for capacity."

Finally, we note the European Commission, in its role as competition regulator, launched an inquiry into capacity mechanisms (aka CMs) in April 2015. The inquiry was prompted by increasing interest by some member states in CMs. The Commission noted that "public support to capacity providers risks creating competitive distortions in the electricity market … or prevent competitive new entrants from becoming active on the electricity market. This distorts competition, risks jeopardising decarbonisation objectives and pushes up the price for security of supply".[73]

It also noted that "capacity mechanisms should be open to all types of potential capacity providers and feature a competitive price-setting process to ensure that competition minimises the price paid for capacity. Competition between capacity providers should be as large as possible and special attention should be given to new entry. Capacity mechanisms should ensure incentives for reliability and be designed to coexist with electricity scarcity prices to avoid unacceptable trade distortions and avoid domestic overcapacity." [74]

5.4 Durability

Electricity generation assets have relatively long lives. Prospective investors are therefore naturally wary of market arrangements which do not appear durable. When CMs were introduced, this was rated as one of their superior attributes relative to the EOM design, because the latter require politicians and consumers to tolerate (at least the possibility of) very high spot prices at times.

Proponents of CMs argued the likelihood of political intervention would be appreciably lower than with EOMs, because 'spikes' in spot prices would not occur (or at least would be much lower). Indeed, some researchers in New Zealand have raised the possibility that growth in generation with zero (or very low) short run marginal costs will cause extended periods of very low spot prices, in turn raising the level of prices at other times.[75] This could make spot prices so volatile that it may pose an 'existential' challenge to the whole market design, and its governance arrangements.

They note that in theory, it might be argued there is little difference from suppliers collecting revenue during occasional price spikes, or the Government collecting it via capacity charges, as was done when New Zealand last had a 100 percent renewable power system, before 1958. But they note there may be very significant differences in the way those two regimes are perceived by risk-averse investors, the regulator, and by the general public.

While these observations have some weight, an increase in spot price volatility will presumably also elicit a market response. For example, an increasing gap in spot prices between 'windy' and 'calm' periods will likely encourage parties to identify opportunities for increased flexibility from other sources – to capture the value of price differences where it is economic. Storage technologies, such

[72] Bublitz, A. *et al*. (2018). *A survey on electricity market design: Insights from theory and real-world implementations of capacity remuneration mechanisms*. KIT Working Paper Series in Production and Energy 27.
[73] European Commission, *Final Report of the Sector Inquiry on Capacity Mechanisms*, November 2016.
[74] Ibid.
[75] See Philpott, A., *et al.* (2019). *The New Zealand Electricity Market: challenges of a renewable energy system*. Electric Power Optimization Centre.

as batteries and pumped storage, will likely increasingly emerge to arbitrage these opportunities, which will reduce the price differences between peaks and troughs.

Furthermore, because of poor operational performance during past scarcity events, some leading CMs are moving toward penalty regimes which mimic scarcity prices under an EOM (as discussed in section 4.4). If this trend continues, any difference in durability arising from a risk of political backlash over high prices/penalties during scarcity periods may diminish.

More generally, looking at experience over the last decade, the expected durability advantage of CMs is far from clear. As noted in section 4.2.5, Colombia's CM did not work as intended and has been subject to significant and ongoing intervention by the regulator since its introduction.

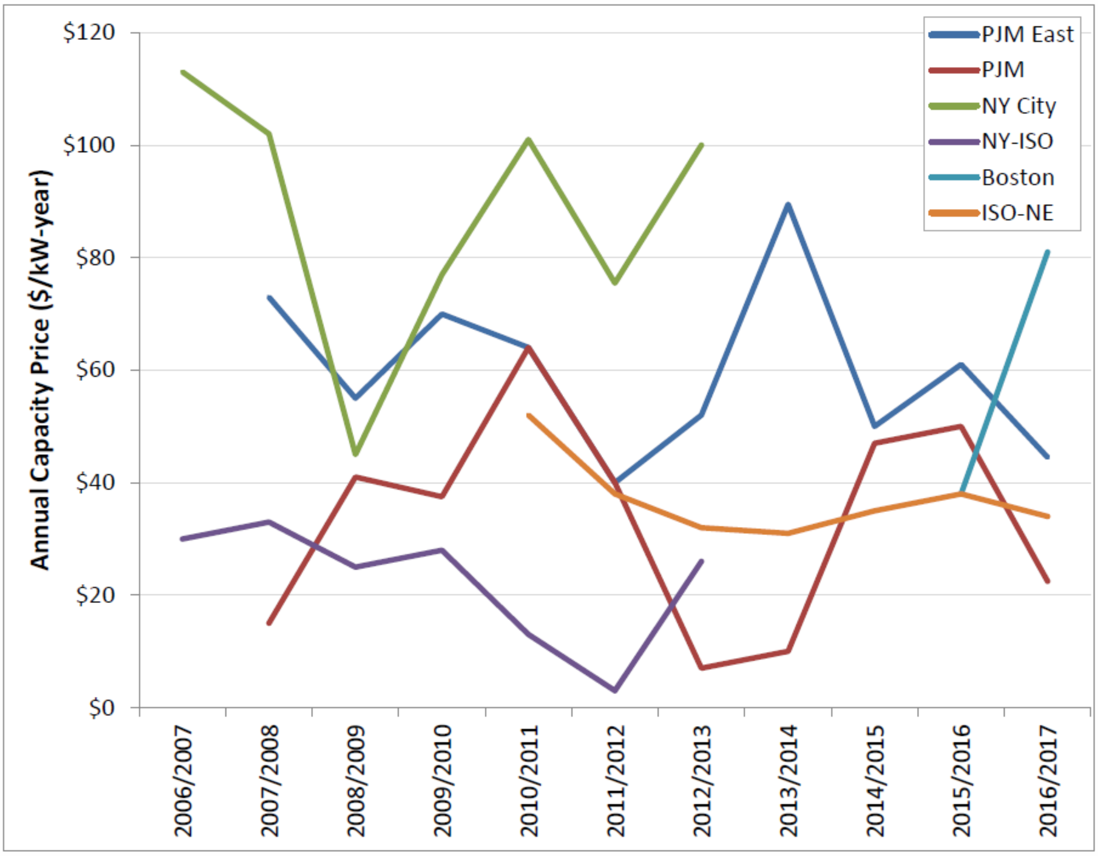
The CM adopted in Western Australia has also undergone significant and ongoing changes – prompted in large part by concerns that it imposed excessive costs on consumers and did not sufficiently incentivise an efficient resource mix.[76]

In relation to the United States, capacity prices have been volatile ever since auctions commenced in the mid-2000s. As shown in Figure 4, annual prices have varied by more than five-fold in some jurisdictions and there has been even greater volatility at the sub-regional level (not shown on the chart, but around ten-fold in one case).

Some of the volatility is due to market fundamentals, such as load growth, fuels prices etc. and cannot be attributed to lack of stability from policy makers. However, 'non-market' factors have also played an important role according to researchers.[77] These include "ongoing rule changes implemented in capacity markets (e.g., changes to the VRR[78] demand curves ..[and] "administrative patterns"—such as load forecasts, CONE estimates".[79]

[76] Government of Western Australia, Department of Treasury, Public Utilities Office (February 2019). *Improving Reserve Capacity Pricing Signals - a Recommended Model.*
[77] Spees, K., *et al (2013)*. *Capacity Markets: Lessons Learned from the First Decade.* Economics of Energy & Environmental Policy.
[78] Variable resource requirement (VRR) refers to a mechanism where the price cap in a capacity auction varies with the current system margin. If the system is tight, a higher cap applies, and vice versa.
[79] Jenkin, T. *et al.* (2016). *Capacity Payments in Restructured Markets under Low and High Penetration Levels of Renewable Energy*. National Renewable Energy Laboratory, US Department of Energy.

Figure 4: Capacity prices for CMs in the United States (auctions between 2006 to 2013)



Source: Federal Energy Regulatory Commission (2013). *Centralized Capacity Market Design Elements*. Staff report no. AD13-7-000

In April 2018, PJM sought approval to further amend its capacity auction rules to address increasing volumes of generation receiving subsidies from state governments or other bodies. For example, Illinois and New Jersey provide subsidies to some nuclear power plants to incentivise zero emission generation. Some participants saw these arrangements as distorting competition, and convinced PJM to proposal a rule change to address the effect on competition. In June 2018, FERC commissioners in a 3-2 decision declined to approve the change proposed by PJM. As a result, PJM was unable to run the capacity auction scheduled for August 2019, and it remains unclear how or when this issue will be resolved. Speaking about the issue in February 2019, Commissioner Richard Glick (a former energy company executive) said:

> In some regions, capacity constructs are encouraging "substantial amounts of excess capacity beyond the level most people think is reasonable"
>
> "Then we see people proposing to change that to actually increase the price so we can actually have more capacity .. and to me that's not good for consumers and arguably is not just and reasonable"
>
> "It's incredibly complex .. and we constantly get proposed changes .. I just worry that we're making it a lot more complicated than it is and not necessarily producing the results"
>
> "We need to figure out a new approach to capacity markets if we're going to have them."[80]

[80] See www.utilitydive.com/news/glick-calls-for-new-approach-to-capacity-markets-in-wide-ranging-naruc-ta/548337/

A similar dynamic has recently unfolded in Great Britain. Although the European Commission authorised Britain's capacity mechanism in 2014, that authorisation was overturned by a European court decision in late-2018 when the mechanism was found to selectively favour some forms of generation, and therefore distort competition. Further auctions and capacity payments under the pre-existing mechanism were put on-hold for almost a year. In October 2019, the mechanism was reinstated following a detailed further investigation by the European competition authorities.[81]

5.5 Innovation

Arguably, innovation is the greatest source of efficiency in the long run. Hence, electricity market arrangements should provide incentives to encourage and reward innovation. This is an area where the EOM design is generally considered to outperform CMs. In large part, this stems from the less prescriptive nature of EOM arrangements relative to CMs.

An example is the concept of firmness. This has a temporal dimension: sometimes firmness is needed for hours, sometimes for days, and sometimes for weeks or months. Often, the type of resource most suitable for the provision of short-term firmness is different to that suited to longer-term firmness.

In a CM, the regulator must define the concept of firmness. For example, the regulator will specify the period of sustained operation that a DR provider or generator must operate to avoid penalty – in terms of hours, days or weeks etc. This period will effectively set the firmness 'standard' applying to all capacity procured under the CM and narrow the focus of innovation toward the regulator's view of needs – rather than the full spectrum of requirements in the system.

More generally, technological development has increased the difficulty in reaching broad consensus over what reliability requirements and metrics should be. Legitimate differences in opinion over the reliability value of demand response, intermittent renewable energy and dispatchable generation will arise. As resources become more diverse, the challenge of forecasting their value for reliability months and years in advance greatly increases.[82] Indeed, some researchers go so far as to argue that CMs place the 'initiative' for innovation in the hands of the regulator.[83]

By contrast, in an EOM design, spot prices can reflect the value of firmness in each different timeframe.[84] The 'broadcast' incentives provided by spot prices in an EOM design are likely to be especially important for mobilising distributed resources – such as charging (and potentially discharging) of electric vehicle batteries. By contrast, the greater standardisation and centralisation of decision-making required with CMs is likely to be less supportive of innovation.

This theoretical advantage is illustrated by recent experience in Australia's EOM. Innovation is occurring to facilitate the entry of intermittent renewable generation. One generator (ERM) is offering to sell two hedge products which help to 'firm' the output from solar generators. The first product provides greater certainty about the value of electricity produced during daylight hours, for periods that broadly match the production profile of single-axis tracking solar generators. The second product addresses the largely predictable need to cover the absence of generation from the approach of sunset to sunrise. ERM anticipates these products will allow solar generators to sell flat, round-the-clock swaps, therefore leaving themselves exposed to spot prices for only the few hours that their solar generation does not correlate with the firming products.[85]

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[81] See https://europa.eu/rapid/press-release_IP-19-6152_en.htm

[82] Bushnell, J. (2017). *Capacity Markets at a Crossroads*

[83] Auer, H. and Haas, R. (2016). *On integrating large shares of variable renewables into the electricity system*. Energy 115, 1592–1601

[84] Unless the time interval is shorter than the length of the spot market trading period.

[85] See: www.energycouncil.com.au/analysis/firming-renewables-the-market-delivers/

Likewise, wind firming products have been developed by AGL, and provide compensation when wind generation is less than the forecasted average wind generation. The pay-out is based on the difference between a strike price agreed at inception and the spot price. The rationale for this product is to allow wind generators to firm up their generation volumes. The product is currently based on total wind generation in a particular state. This means individual wind farms will have basis risk when their wind patterns are uncorrelated to the state as a whole. However, it is possible that this product could evolve to offer more specific hedges to wind generators. While these products are in their early stages, they provide examples of the innovations facilitated by an EOM design.

5.6 Conclusion in relation to costs

Costs to consumers are expected to be higher under CMs than EOMs. The key reasons are:

- CMs are prone to creating substantial excess supply capability. Key decisions must be made by a central party who will face lop-sided incentives. They will typically err on the side of caution because any failure in the form of power cuts will be visible, whereas the costs of over-building are harder to see.
- CMs are more likely to create a distorted resource mix between generation types and DR because of the prescriptive rules required to measure firm capacity. CMs are also more susceptible to lobbying by special interests seeking preferred treatment for their particular options.
- CMs are less able to facilitate and reward innovation – the most important source of cost savings in the long-run – because of the higher level of centralised decision-making and prescription.
- CMs appear no more durable that EOMs – as the greater centralisation of decision-making and considerable administrative discretion encourages continued lobbying by special interests.

6 New Zealand specific issues

If a CM were to be considered for New Zealand, there would be some specific issues to address, as outlined below.

6.1 Joint capacity and energy adequacy issues

Most CMs in operation in the world today are designed to address capacity adequacy. However, New Zealand faces both capacity and energy adequacy risks.[86] As far as we are aware, the only CM designed to address energy adequacy is that operating in Colombia. It is unclear how effectively that scheme addresses capacity risk. As discussed in section 4.2.3, Colombia's scheme has yielded mixed results in addressing energy adequacy issues and cannot be regarded as a stable and effective model.

Any CM design for New Zealand would need to consider how to determine the firm energy capability of generation and DR providers over multiple timeframes – to ensure providers do not oversell their capability. Determining the volume of firm energy capability would be a major challenge – as it has proven to be in Colombia. Moreover, a CM would need a mechanism to frequently (more than annually) reassess the firm capability of providers – because it can be affected by starting storage levels, outages, thermal fuel supply etc.

In addition, New Zealand faces capacity risks (at least in the North Island), so the CM would need to determine both firm capacity and energy capability for resource providers. The answers are likely to differ for some plant (e.g. 100% of a hydro generator's nameplate capability could be assessed as firm capacity, but its firm energy capability might be assessed as, say, 50%).

Likewise, consumers (or their agents) would need to have purchase obligations that specify both capacity and energy requirements. For example, some consumers might be able to reduce demand for a short period (reducing their capacity cover requirements) but be unable to sustain such reductions (meaning they need 'full' energy cover).

These types of factors mean the CM monitoring system would need to track both capacity and energy rights for all market participants. The monitoring system would likely need to be very prescriptive, to ensure that all demand sources have procured adequate capacity and energy rights, and that suppliers have not over-sold their physical ability to deliver such rights.

The CM could be less prescriptive if it used economic penalties to deter under-procurement by purchasers and over-selling by providers. However, to be effective, this would need to mimic the spot price in an EOM – which begs the question of whether a CM would be preferable.

6.2 Locational issues

CMs effectively impose a contract obligation on demand-side parties (or agents), requiring them to hold purchase rights to match their assessed load. To be effective, the rights also need to match their location. In some CMs, there is a single price zone (e.g. Western Australia) so this is straightforward. Where jurisdictions have locational price differences, purchasers need to hold the requisite rights at each location. However, as far as we are aware, all jurisdictions with operating CMs have either a single locational price or zonal pricing for load (e.g. PJM). We are not aware of any CM jurisdictions that have full nodal pricing for purchasers.

[86] By 'energy adequacy', we mean having sufficient supply or DR capability to address a reduction in supply that is sustained over weeks or months.

However, New Zealand operates with full nodal pricing for both generation and demand. This introduces a significant complexity in the task of assessing and monitoring adequacy because judgments need to be made about the extent to which purchase contracts at location Y are acceptable to cover load at location Z. The rules that the regulator adopts in this area would have important financial consequences for both suppliers and purchasers.

6.3 Market size

The small size of the New Zealand market increases the level of concern about market power in relation to both buyers and sellers of rights, and these are heightened further when regional constraints are accounted for.

A related issue is the relative lumpiness of some risks in the New Zealand system. It is possible that the total number of firm rights offered by generators will be below the ‘after diversity’ supply capability of the system as a whole. This situation could arise if individual generation owners, concerned about the potential penalty for non-performance, reduce their capacity offers to the total nameplate capacity of their portfolio, less their largest single unit. Viewed from the individual generation owner’s perspective, this may be rational. However, if all owners do it, that could remove an appreciable portion of supply from the capacity market – even though the likelihood of all those units being physically unavailable at the same time is vanishingly small. In theory, this issue could be addressed by co-insurance arrangements between suppliers, but it is unclear how practical that would be.

These types of issues would likely reinforce the need to consider price floors or caps on firm rights – which in turn might constrain the effectiveness of the CM from an adequacy perspective.

6.4 Transitional issues

Introducing a capacity mechanism in New Zealand would entail a major redesign. It would not just be a simple add-on – especially given the need to address energy and capacity adequacy issues. New Zealand participants have geared their businesses around an EOM design. For example, suppliers and purchasers have entered into bilateral hedge contracts – some of them for relatively long terms. It would be important to try to accommodate these prior commitments if there was any move away from an EOM. This would be possible if the CM design allowed purchasers to contract bilaterally – and there is no obvious reason to preclude such contracts. Indeed, allowing bilateral contracting is relatively common among CMs overseas and provides more flexibility for participants.

Assuming bilateral contracts was to be allowed, it would be necessary to determine how each existing contract is to be ‘counted’ in terms of creating firm capacity and energy rights. It would be very important to have a clear methodology in this area. Purchasers would obtain credits from any qualifying contracts, and that would reduce their net obligation to buy further contracts. Conversely, for parties who have sold qualifying contracts, it would reduce their headroom to make further such contract sales. It is also possible that parties to existing bilateral contracts would make amendments to their terms, so that they better conform with the requirements of a CM.

More generally, adoption of a CM would likely require some years to fully implement – based on experience in other markets. In the meantime, resource providers could delay or shelve investment plans until the design of a CM is finalised. For this reason, there is a risk that moving to a CM could degrade reliability initially, unless careful thought is given to transitional issues.

7 Conclusion

This chapter summarises our overall observations. It also makes some suggestions for future consideration if concerns emerge about resource adequacy.

7.1 CMs and EOMs have different strengths in relation to reliability

CMs provide a high level of assurance that sufficient generation and DR will be *built.* This is because CMs create explicit commitments to invest in supply capability. CMs can also include tests to ensure that parties' commitments are backed by 'steel in the ground'. Having said that, many EOMs (e.g. New Zealand, Nord Pool, Singapore) have performed well in ensuring sufficient capacity is *built*. So, the real difference between CMs and EOMs is the level of ex ante assurance they provide. CMs provide a higher degree of assurance about the level of *built* capacity because that variable is under the direct influence of the regulator/market operator.

Turning to operational issues, CMs do not provide assurance that resources which have been *built* will actually be *available* when required. Indeed, experience to date suggests that EOMs will almost certainly perform better than CMs on this front, because EOM spot prices create stronger signals to make all resources available during periods of scarcity.

Given these factors, the overall assessment of the two designs on reliability is not clear-cut and depends in large part on what policy makers are most worried about – ex ante assurance about the level of *built* capacity, or that resources which have been built will be *available* when required.

7.2 CMs tend to increase costs to consumers

Costs to consumers are expected to be higher under CMs than EOMs. The key reasons are:

- CMs are prone to creating substantial excess supply capability. Key decisions must be made by a central party who will face lop-sided incentives. They will typically err on the side of caution because any failure in the form of power cuts will be visible, whereas the costs of over-building are harder to see.
- CMs are more likely to create a distorted resource mix between generation types and DR because of the prescriptive rules required to measure firm capacity. CMs are also more susceptible to lobbying by special interests, seeking preferred treatment for their particular options.
- CMs are less able to facilitate and reward innovation – the most important source of cost savings in the long-run – because of the higher level of centralised decision-making and prescription.

7.3 Market power

CMs and EOMs are both susceptible to competition issues. Both require careful design to minimise the scope for the exploitation of market power.

7.4 Durability

In theory, CMs should be more durable than EOMs because they do not rely on spot prices being able to reach very high levels in a scarcity event. However, because of poor operational performance during past scarcity events, leading CMs are moving toward penalty regimes which mimic scarcity prices under an EOM. So, the difference in durability from this source may lessen over time.

More generally, where CMs have been adopted, they are under almost constant change – with some modifications being very significant. Furthermore, experience suggests CMs are more exposed to legal or regulatory challenges due to the greater centralisation of decision-making and considerable administrative discretion conferred on the central party.

7.5 What should New Zealand do?

Neither EOMs nor CMs are perfect. Both have strengths and weaknesses – and experience is still being accumulated on their relative performance. Based on the international experience with EOMs and CMs to date, we suggest the following actions.

7.5.1 Keep an eye ahead

New Zealand should keep an eye ahead for any sign of potential or emerging problems. Identifying concerns at an earlier stage provides more time for careful examination to determine if problems are real or perceived (see below). If concerns are borne out, early identification also gives more time for proper diagnosis of causes, and identification of solutions.

New Zealand already has tools to facilitate monitoring of the forward outlook for supply and demand. These should be actively employed – focussing particularly on the supply margin and any indications that investment signals are not working as expected. This includes factors such as whether contract prices are persistently at levels above the cost of new supply, and/or whether there are blockages to new investment.

7.5.2 Identify whether any reliability concerns are due to investment adequacy

Electricity systems can exhibit reliability concerns for a wide variety of reasons. This is true of systems with EOM and CM designs. Indeed, reliability concerns were around long before electricity markets were created in the 1990s.

If reliability concerns do emerge, it is important to identify the real source of those concerns. For example, reliability concerns may be unrelated to investment adequacy and the choice of market design.

This was the case with reliability concerns which emerged in the aftermath of the state-wide power cuts in South Australia. Those stemmed from tripping of wind generators following a power system disturbance. Adopting a CM would not have addressed these concerns because they revolved around technical standards. Correctly diagnosing the concern is crucial to avoid solutions that are unnecessary, or worse, counterproductive.

7.5.3 Improve EOM design where feasible

If investment adequacy concerns do emerge, it would be important to understand whether they can be addressed without complete redesign of the electricity market. For example, adequacy concerns may be due to aspects of an EOM design that unintentionally cause problems – such as insufficient opportunity for DR to influence prices or poor price formation in scarcity situations. As the European Commission noted in November 2016, parties should first seek to "address their resource adequacy concerns through market reforms [..] no capacity mechanism should be a substitute for market reforms."[87]

Concerns may also arise for reasons that are temporary in nature and not directly related to the wholesale market design per se. This was the case with Germany which faced increased supply uncertainty due to the accelerated phase-out of nuclear power. After considering a wide range of options, Germany chose to retain an EOM design, but placed some generation in a temporary strategic reserve to facilitate the transition as nuclear plants phase out.

[87] European Commission, *Final Report of the Sector Inquiry on Capacity Mechanisms*, November 2016

7.5.4 Understand the risks and costs of CMs relative to EOMs

Both EOMs and CMs have costs and risks – and there is no perfect option. If CMs are seriously explored in depth, it would be important to understand the likely costs and risks.

Drawing on international experience would be very important in this regard. Indeed, in the global transition toward net zero carbon, other countries are likely to strike challenges before New Zealand because we have the advantage of a large and relatively flexible hydro generation base to ease our transition. This means that New Zealand should be able to benefit from the design experiences of other countries – and not repeat their mistakes. In this context, it is striking how much has changed among EOM and CM jurisdictions in the last five years.

Having said that, there are some critical issues where international experience is not very useful – simply because our issues are distinct such as exposure to drought risk (see chapter 6). New Zealand would need to develop its own assessment of costs and risks in relation to these issues.

Appendix A. Overview of CMs

Overview of implemented CRMs around the world. Sources: Bhagwat et al. (2016b), Byers et al. (2018), Cejie (2015), Chow and Brant (2018), Deutscher Bundestag (2016), EirGrid plc and SONI Limited (2017), European Commission (2014, 2016a,b,c, 2017a,b), Government of Western Australia (2017), Hancher et al. (2015), Harbord (2016), Midcontinent Independent System Operator, Inc. (2019), New York Independent System Operator (2018), Patrian (2017), PJM (2018), Roques et al. (2017), Single Electricity Market Committee (2016), Southwest Power Pool, I. (2018a,b), Svenska Kraftnät (2016).

Type	Market area	Administrator		Eligible technologies				Status[1]	
		TSO/ISO	RA	TPP	VRES	DSM	IC		
Strategic reserve	Belgium	x	x	x		x		Active	(2014)
	Germany	x	x	x		x		Planned[2]	(2018)
	Sweden	x		x		x		Active	(2003)
Central buyer	Colombia		x	x	x			Active	(2006)
	Ireland[3]	x	x	x	x	x	x	Planned	(2017)
	Italy[3]	x	x	x		x	x	Planned	(2018)
	Poland[4]	x	x	x	x	x	x	Planned	(2018)
	UK	x	x	x	x	x	x	Active	(2014)
	US – ISO-NE	x		x	x	x	x	Active	(1998)
	US – MISO	x		x	x	x	x	Active	(2009)
	US – NYISO	x		x	x	x	x	Active	(1999)
	US – PJM	x		x	x	x	x	Active	(2007)
De-central obligation	Australia – SWIS	x	x	x	x	x		Active	(2005)
	France	x		x	x	x	x	Active	(2015)
	US – CAISO	x	x	x	x	x	x	Active	(2006)
	US – SPP	x		x	x	x	x	Active	(2018)
Targeted capacity payment	Spain[5]	x		x				Active	(2007)

Abbreviations: CAISO—California ISO, DSM—demand side management, IC—interconnector, ISO—independent system operator, ISO-NE—ISO New England, MISO—Midcontinent ISO, NYISO—New York ISO, PJM—Pennsylvania-New Jersey-Maryland Interconnection, RA—regulatory authority, SPP—Southwest power pool, SWIS—South West interconnected system, TPP—thermal power plant, TSO—transmission system operator, VRES—variable renewable energy sources

[1] Year of (planned) implementation in parentheses. The year refers to the respective mechanism currently in place, however, other mechanism may have been used before.

[2] In Germany, two separate mechanisms have been discussed that can be classified as a strategic reserve. In 2016, a security stand-by arrangement for lignite-fired power plants with a total capacity of 2.7 GW was introduced in order to attain national climate targets. Furthermore, an additional so-called capacity reserve is supposed to be active in winter of 2018/19 to ensure generation adequacy. However, as the European Commission still assesses whether the capacity reserve complies with EU state aid rules, it is unclear whether the planned schedule can be met.

[3] To date, targeted capacity payments are used.

[4] Currently, a strategic reserve is implemented.

[5] This refers to the now in place "availability service" mechanism. An additional mechanism named "investment incentive" was abolished in 2016.

Source: Bublitz, A. *et al* (2019). Energy Economics 80, Figure 2.