Infigen Energy Limited
Level 17, 56 Pitt Street
Sydney NSW 2000
Australia
T +61 2 8031 9900
F +61 2 9247 6086
www.infigenenergy.com

27 SEPTEMBER 2019

To: Energy Security Board
Submitted via email

Re: **Response to Post-2025 Market Design**

Infigen Energy (Infigen) welcomes the opportunity to make a submission to the Post-2025 Market Design process. Infigen owns/operates a portfolio of wind and firming capacity across New South Wales, South Australia, Victoria and Western Australia. Our renewable portfolio includes 670 MW of vertically integrated wind plus c90 MW of contracted capacity in Victoria. Infigen also owns and operates a portfolio of dispatchable firming capacity including a 123 MW open cycle gas turbine in NSW, a 25 MW / 52 MWh battery in SA (commissioning October 2019) and will soon take possession of 120 MW of dual fuel peaking capacity in SA. Our Development and Capital-Lite pipeline has projects at differing stages of development covering wind, solar and dispatchable firming capacity.

1. OVERVIEW

The NEM has undergone significant stress following sudden coal plant closures. From a physical system perspective, closures at-scale exposed gaps in services procured vis-à-vis system strength, system security and the integration of distributed energy resources (DER). Policy uncertainty, random government interventions and unanticipated changes in plant entry and exit dynamics has resulted in a more challenging power system.

However, in our view the NEM's fundamental wholesale market design – comprising the spot electricity market and forward derivatives market – remains strong. In response to changing market dynamics, Infigen has made significant investment commitments in Variable Renewable Energy (VRE) capacity and dispatchable firming and fast response capacity, including:

- Developing the 25MW / 52MWh Lake Bonney Battery Energy Storage System in SA;
- Purchasing the 123MW Smithfield Gas Turbine plant in NSW;
- Committing to a long-term lease of four SA Gas Turbines (120MW) from the South Australian Government, and preparing to move the GTs to a new site and convert to dual fuel;
- Developing the 113MW Bodangora Wind Farm in New South Wales;

- Selling the 57MW Cherry Tree Wind Farm project and entering into a long-term PPA as the off-taker of its energy.

Accordingly, Infigen considers the NEM remains highly investable for the right assets, with the right business models.

However, while our view is that the NEM wholesale market design is not broken, it is *incomplete* and characterised by missing markets. Given the transformation underway, not all services required for the efficient, secure and reliable operation of the changing system are being valued or appropriately procured. As a result, the power system is experiencing or approaching binding limits across a range of technical and economic parameters.

Various (urgent) NEM Rule changes have addressed some of the more immediate issues confronting the NEM. But predictably, some of these urgent Rule changes have created new problems. For example, the grid Connection process is now more complex, and in our experience this has resulted in very material lags to valuable flexible capacity being commissioned. Substantial delays increases the cost and risk of project commitment and if unresolved, may increase system risks more generally as the NEM's aging thermal fleet progressively retires. This may create unintended (albeit temporary) gaps in replacement capacity in future periods.

The key points of our submission are that:

- The ESB needs to be perfectly clear on what 'problem' needs to be solved, and ensure that any proposed changes are likely to address it.

- The NEM energy-only market design is generally functioning well, but reducing random government interventions and policy/regulatory uncertainty will be critical in order to maximise welfare. We note that:

  - Energy prices are high relative to historic levels, but this reflects resource costs. Changing the market design does not alter resource costs.

  - Evidence from the NEM is that 'reliability of supply' over our market's 20+ year history (i.e., more than 80-region years' experience) has met the reliability criteria in all but a handful of instances.

  - Evidence from the NEM is that 'security of supply' is increasingly challenging. Currently procured Frequency Control Ancillary Services (FCAS) and non-specified services currently provided "for free" by online generation are likely to be inadequate in a post-2025 environment.

- Critical near-term challenges that need to be addressed include:

- Better management of emerging system strength constraints.

- Urgent improvements to the Connection process to reduce timelines associated with investment commitment and subsequent commissioning (i.e. uncertainty and delays in processes).

- Better visibility and control over DER.

- Any notion that a fundamental change to the NEM's wholesale market design can be orchestrated without disrupting the flow of debt and equity capital into new merchant plant capacity is, in our view, simply not correct. Indeed, a fundamental change to the NEM design may well trigger Material Adverse Change clauses in existing financing packages, and impact incumbent plant re-financing efforts.

- Organised Capacity Markets do not appear to offer value to the NEM. Nor do organised Capacity Markets appear well suited for a changing NEM system. On the contrary, they may increase complexity and reduce flexibility due to the difficulty of defining what constitutes 'capacity'.

- Similarly, Day-Ahead Markets would not, in our view, reduce the operational complexity of the NEM. However, a voluntary organised *financial* Day- to Week-Ahead market, similar to AEMO's STFM concept, may provide participants with increased options for adjusting financial positions closer to real-time.

To ensure the NEM is robust from 2025 and beyond, we recommend that the ESB:

- Clearly articulate the specific problems to be solved, along with solutions designed to address the specific problems – noting that in our view the overall market design is *at best* a second order issue.

- Help coordinate the various complementary and sometimes competing Rule changes that are currently under consideration.

- Work with AEMO to identify current and pre-empt emerging limits in power system operations as it transitions to higher VRE market shares.

- Work with AEMO and the AEMC to propose new FCAS markets for system services that have been historically un-valued or under-valued including inertia, system strength, primary frequency control and ramping services. If the market has clear signals for new investment, it will be better prepared for even more rapid change in the future. And finally,

- Approach this Review through the lens of an accelerating but smooth transition to a clean energy future.

Our specific proposals include:

- Conducting detailed modelling in order to define which system security services might be procured ahead of time in order to ensure that the unexpected closure of another coal power station does not cause system security risks, major disruptions, or delays to requisite new investment.

- Considering additional spinning and/or non-spinning reserve markets, ramping markets, and/or an "Operating Reserve Demand Curve" to ensure that the scheduling of reserves is consistent with future system requirements.

2. HAS THE NEM MARKET DESIGN FAILED?

While stresses experienced by the NEM might prima facie lead towards a market re-design, it is critical to ensure that any changes envisaged would actually *fix* a specific problem – either now or in the future. Otherwise, not only will investment be deferred but the *actual* problems facing the NEM will not be addressed, and, new and unanticipated problems will almost certainly be created.

We caution the ESB against jumping to another market design without first thoroughly understanding the issues facing the NEM, and identifying how best to deal with them. We note that:

- Most global market designs have been reasonably successful to date at delivering reliable supply, including in Australia's energy-only, gross pool design[1].

- Globally, no loosely interconnected market has been forced to deal with the VRE market shares observed in Australia (i.e. SA), and so no practical evidence exists to suggest that an international market design might work better here.

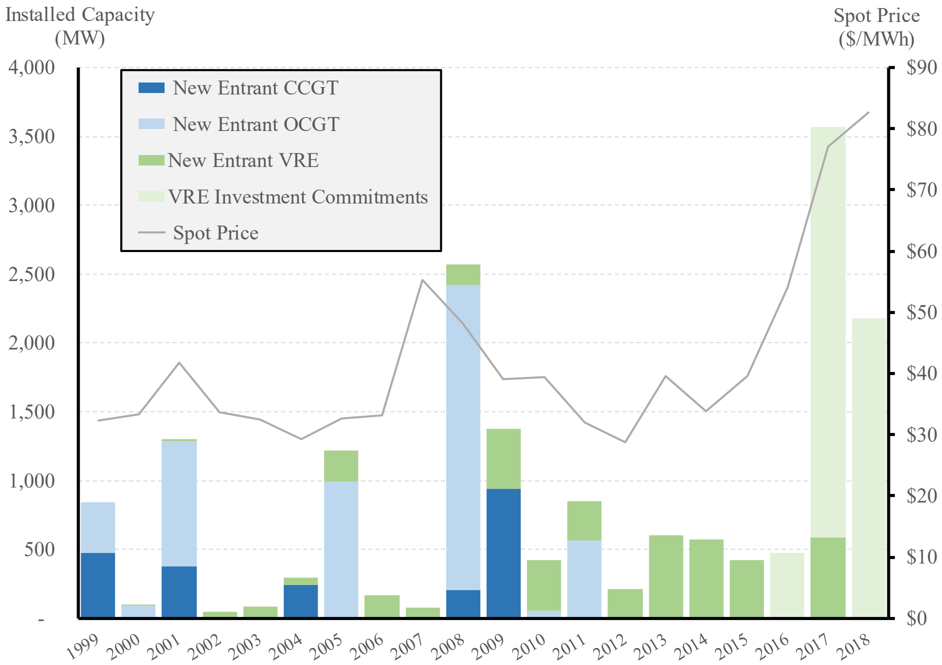
- The NEM has recently been exposed to two core problems, viz. rising resource costs (i.e. marginal coal and natural gas), and rapid & uncoordinated coal plant closures at-scale.

[1] See for example Reliability Panel, (2018), Final Report – reliability standard and settings review 2018, AEMC, Sydney at Page 53.
Wood, Dundas & Percival, (2019), "Keep calm and carry on- managing electricity reliability", Grattan Institute, Melbourne.
Simshauser, (2019), "Lessons from Australia's National Electricity Market 1998-2018: strengths and weaknesses of the reform experience, EPRG Working Paper No.1927, University of Cambridge.

2.1 Is there "insufficient capacity" in the NEM?

We observe claims that there is *"insufficient capacity"* or a generalised *lack of investment* in new capacity in the NEM. We see little evidence of this based on market data as Figure 1 illustrates:

Figure 1 - NEM new entrant plant and investment commitments (1999-2018)



Sources: ESAA, AEC, AEMO, CEFC, Bloomberg

These claims can be evaluated in different ways, including from the perspective of the reliability of supply, the efficiency of investment levels, price dynamics and security of supply. We review these below.

2.1.1 Is there a reliability of supply failure?

The NEM design, like most global market designs to date, has provided an effective platform for investing in new generation. Setting aside the question of whether the Reliability Standard is appropriate, it is difficult to argue that the NEM market design has not delivered on its target. The wholesale power market has delivered high levels of reliability in almost every year as Figure 2 notes:

Figure 2 - Historical unserved energy (2007-08 to 2018-19)

If the Reliability Standard was forecast to be breached on an ongoing basis, the notion that the NEM has or will fail to deliver Resource Adequacy would have some basis. However, forecast Unserved Energy (USE) in all regions is projected to meet the standard into the future[2]. AEMO's 2019 ESOO shows that even in the absence of *any* new investment, the reliability standard is projected to be achieved out to 2030. While additional coal plant closures beyond Liddell Power Station are probable (given an aging thermal fleet, and the need decarbonise the power system), AEMO has not identified any reliability of supply issues at this time.

Even though USE is no longer projected to be zero, this is not evidence of a broken market, but rather, the NEM has avoided *"gold plating"* (noting that no power system globally either assures nor aims for 100% reliability of supply due to the onerous cost of doing so). Conversely, when there was significant excess capacity over the period 2010-2015, it was investors who bore the cost of oversupply, not consumers.

We support ongoing discussions of whether consumer preferences have changed (e.g. AEMC survey of value of customer reliability). The trade-off between cost and reliability is regularly reviewed by the Reliability Panel, which includes extensive consultation with both industry and consumer groups. Recent progress towards activating the demand-side[3] will further strengthen this link, providing more

[2] The 2019 ESOO projects no breach of the standard provided that units currently on outage are returned to service as disclosed by plant owners. Under a probabilistic approach under which those units fail to return to service prior to the Q1 Summer period, AEMO projects the standard to be breached in Victoria. We note however both owners are listed companies with continuous disclosure obligations, and neither organization has signaled return to service delay.

[3] For example, the AEMO/ARENA trial for delivering RERT from demand response, AEMO working towards procuring ancillary services from demand response, and the AEMC Demand Response rule change.

opportunities for individual customers to make consumption decisions that reflect their personal price and reliability preferences.

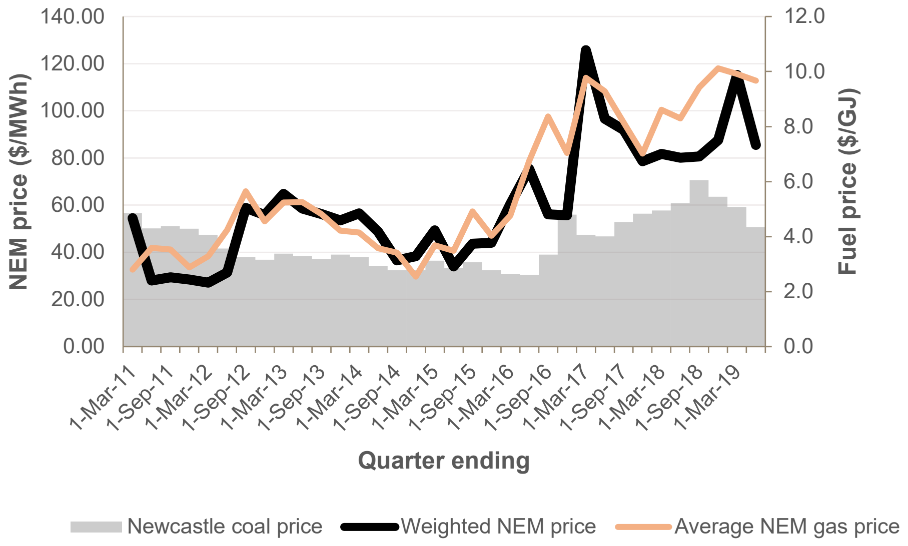
2.1.2 Is there an inefficient level of generation investment?

The effectiveness of the NEM might be evaluated in terms of whether wholesale prices remain above the relevant new entrant technology cost. If new generation plant is not being developed in response to higher prices, this would represent a problem. However in our view, we have not observed this in practice. As Figure 1 noted, all prior episodes of sharply rising prices in the NEM have been met with material supply-side investment commitments.

On a forward basis, whether aggregate supply will respond in a timely manner is a complex line of inquiry that requires consideration of all possible barriers to investment and entry lags (see Section 2.2).

Unit gas fuel and marginal coal costs in the NEM have risen substantially (Figure 3) and have underpinned prevailing and forward prices. Elevated gas prices are unlikely to reverse in the absence of significant government action at the State level (i.e. adding new supply).

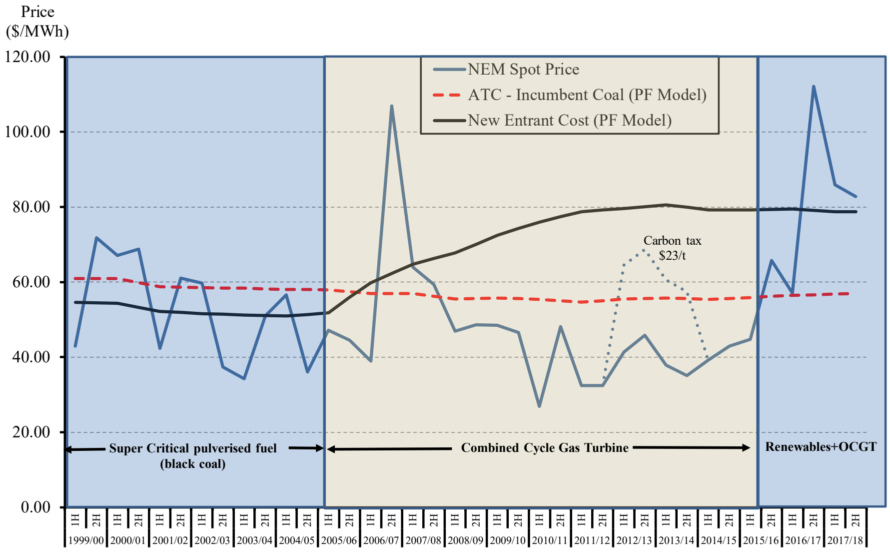
Figure 3 - Wholesale gas, coal and electricity prices



We consider the benchmark new entrant technology set to be VRE plant plus firming, notionally provided by an OCGT plant or equivalent with equilibrium prices indicatively in the range of $70-80/MWh (Figure 4)[4]. This aligns closely with ASX base futures prices 1-3 years out, and suggests NEM investment decisions remain entirely rational, in spite of certain barriers outlined later in Section 2.2.

[4] For full details of calculations, see Simshauser and Gilmore (2019) “On entry cost dynamics and Australia’s National Electricity Market”, *The Energy Journal*, 41(1): 259-288.

Figure 4 - NEM Spot Prices and New Entrant Costs: 1999-2018 (constant 2018 $)



2.1.3 Is an increase in negative spot prices a problem?

Zero price events have become more common and reflect that an efficient, least-cost low emissions system will produce surplus energy in certain periods.

Negative prices indicate a surplus of generation plant seeking to produce in a given period, *and*, that there is a cost associated with reducing supply. Non-distortionary negative price events provide a valuable investment signal: highlighting the value of flexible capacity that can operate around stochastic loads and VRE plant, and opportunities for storage. The marginal (inflexible) coal generator will see such market signals and either invest in flexibility, such as reducing minimum stable loads, or retire and be replaced by a portfolio of VRE and fast-start dispatchable resources.

However, incentives exist for renewable generators to run at negative prices and this has the effect of *amplifying* negative price events. VRE plant bid output at the opportunity cost of LGC prices. This is *not* a NEM wholesale market design issue per se, but an inherent design element of the LRET legislation.[5]

In hindsight, legislation governing the creation of LGCs should have specified that Certificates cannot be created during negative price events so as to ensure an orderly (physical) spot market prevails. This distortion to physical market operations could be moderated by making *prospective* changes to LRET legislation to prevent

[5] Other episodes of disorderly bidding may include strategies designed to avoid being constrained-off, even when prices are positive (e.g., system strength constraints in South Australia) – these may occasionally have the unintended effect of leading to negative prices during unexpected events.

LGC creation during negative price periods (for example, applying such a principal to all projects committed from 2021 onwards).[6]

2.1.4 Have the FCAS markets failed?

Frequency in the NEM has been increasingly deviating from the target of 50 Hz. AEMO suggests this may be a threat to system resilience[7] - responding to non-credible events. The AEMC is currently considering three Rule changes relating to the provision of Frequency Control.

However, the mainland NEM has met the Frequency Operating Standard (FOS) albeit with a brief exception before AEMO procured additional Regulation FCAS during the 2018/19 financial year. Specifically, the FOS does not place any requirement on AEMO, nor identify any specific services to procure, as to how Frequency should be maintained *within* the normal band. It therefore does not seem that the NEM's eight FCAS markets have failed[8]. Our FCAS markets have delivered precisely what was asked, viz. the low-cost provision of sufficient headroom and response to meet the FOS[9].

Infigen supports reviewing and if determined appropriate by the Reliability Panel, revising the types of contingency events that the NEM should be able to withstand. This should then drive how FCAS markets are defined and procured. It may be that additional services or responses are required to ensure the system remains in a secure state. We note that recent proposals for *the taking* of FCAS services provided by incumbent coal generators, without payment through a mandatory requirement, will mute appropriate price signals for new investment.

We also note that although FCAS prices have increased significantly over the past three years, there has been rapid investment in new flexible battery projects by both private investors and by governments (Figure 5). While industry and regulators were caught unprepared by the rate of new binding constraints (particularly in SA), new capacity was developed rapidly. Once again this suggests FCAS markets have functioned effectively. In contrast, the Connections process has deteriorated – something we elaborate on in Section 2.2.

---

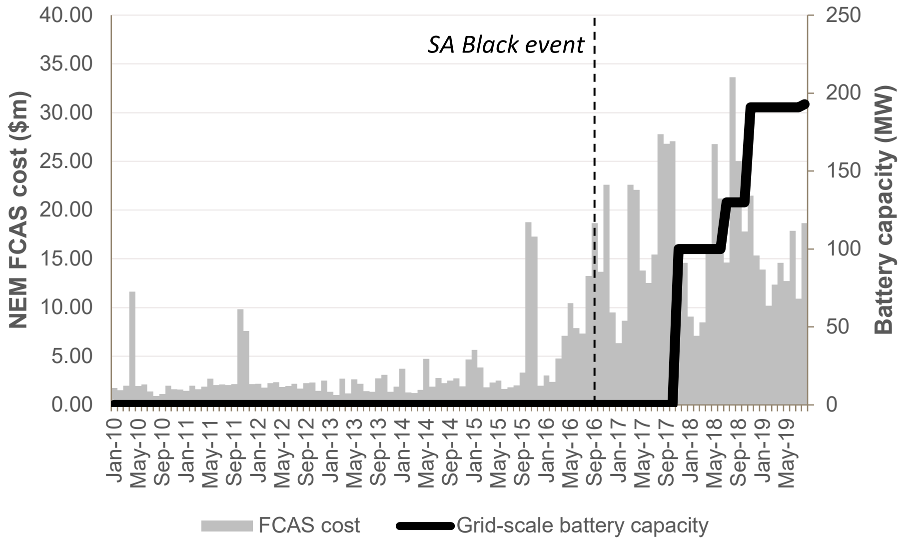
[6] The obvious corollary here is that an explicit price on CO_2 emissions (as opposed to production subsidies) would produce more efficient spot market outcomes.

[7] AEMO always seeks to maintain the system in a secure state and procures sufficient services to do so.

[8] Riesz & MacGill, (2013), "Frequency Control Ancillary Services – is Australia a model market for renewable integration", Centre for Energy and Environmental Markets, University of NSW, Sydney, Australia.

[9] Pollitt & Anaya, (2019), "Competition in markets for Ancillary Services? The implications of rising distributed generation", EPRG Working Paper No.1928, University of Cambridge.

Figure 5 - NEM FCAS Costs 2010-2019



2.1.5 Has the NEM failed to deliver system security?

AEMO is currently being forced to intervene in the NEM on an almost daily basis. The repeated need for interventions in the South Australian region has sometimes been referred to as evidence of a market failure. However, it is necessary to distinguish between a failure of market design, and the lack of appropriate markets included within a market design.

There are not currently price signals for synchronous resources (short- or long-term) or for the services they provide. The reason for this is that – historically at least – the cost of establishing and operating an organised spot and forward market would have greatly exceeded any benefit.

However, the NEM is now a power system in transition and evidently has not correctly identified, valued and or paid for all required services. This represent an episode of ‘missing markets’ rather than a fundamental market failure per se.

Furthermore, not all problems need to be solved by organised spot markets. A market for synchronous capacity could be established, but that market may well be for ‘tendered supply’ rather than through competitive spot markets (based on expected costs/benefits).

For example, ElectraNet’s analysis of South Australia found that contracting with existing generation would cost $85m per annum (directions would cost $34m pa) whereas new Synchronous Condensers would cost $140-180m. In this particular instance, the approach of procuring a network service appeared to be significantly lower cost than an organised market for exchange. Moreover, once the SynCons have been constructed, Infigen understands the almost daily directions by AEMO in SA are expected to cease.

We support AEMO's proposed Renewable Integration Study that seeks to identify emerging challenges in the NEM. This has the potential to avoid market disruption events (e.g. system strength constraints in SA, Vic and Qld impacting on incumbent projects) that have come from unforeseen changes to the NEM. Having a clear action plan of how to respond to changes *when* they happen (regardless of timing) will be valuable.

It may also be worth investigating the concept of procuring system services for the NEM on a probabilistic "N-1 *planning"* basis vis-à-vis plausible supply- or demand-side[10] shocks. By way of specific example, Networks could investigate options for Synchronous Condensers in locations where marginal coal plant exists, and where grid stability may be at risk under conditions of rapid plant closure. By being *one step ahead*, future system security disruptions could be minimised.

2.2 Barriers to new entry

Our analysis in Section 2.1 is not intended to suggest that investment in the NEM does not face headwinds. However, in our view the barriers to entry and entry frictions that exist are not related to market design. Broader investment hurdles and frictions can be traced to new Connections risk, increasingly random government interventions and policy uncertainty. Our concern here is that barriers and frictions *unrelated* to market design will be tagged to the design itself, instead of the core problems. We note that:

- There are no immediate-term reliability breaches predicted – the AEMO view of VIC aggregate supply for the Q1 2020 summer period is inconsistent with the ASX continuous disclosure obligations of AGL Energy and Origin Energy.

- The requirements of NEM Rules s5.4.3A and 5.4.3B have frustrated entry – these contemporary Rule changes may well be critically important but as a statement of fact, they have materially delayed plant entry. This is completely unrelated to market design.

- The 20%RET is thought to be fully subscribed and policymakers shouldn't be surprised to see a corresponding slowing of VRE plant entry.

2.2.1 Connection uncertainty in the NEM

We noted earlier that power projects are experiencing unexpected *entry lags*. Stock analysts at Bank of America Merrill Lynch[11] recently analysed total 'Observed Delays' associated with power project developments in the NEM. Their project-by-project analysis, presented in Table 1, shows and overall average entry lag of 7½

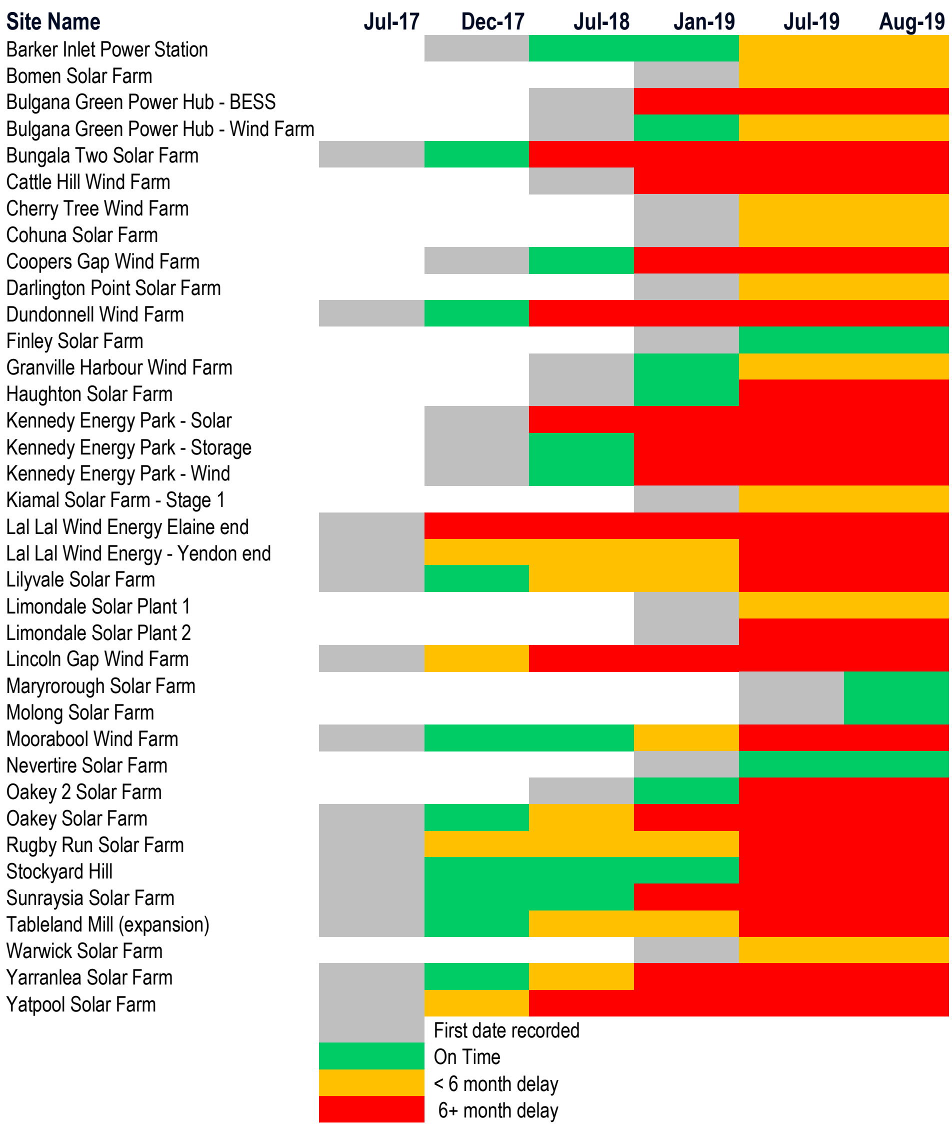
---

[10] For example, closure of a major industrial load.

[11] See Low and Yang, (2019), "The National Electricity Market (NEM): the capacity bomb is still coming", *Bank of America Merrill Lynch*, Australian Utilities Equity Research, 2 October 2019.

months. Parallel analysis by CEFC across 14 specific power projects found an average entry lag of 6.9 months. Infigen's own experience with project development is consistent with these broader market research results. Central to entry lags is the Connection process.

Table 1: Observed Delays of Development Projects under construction in the NEM



Source: Low & Yang (BofA).

Under new Rules, multiple iterations of NSP and AEMO Connection studies, the need to develop additional assets (e.g. Synchronous Condensers) and the relatively new but understandable requirement from financiers to have these matters resolved prior to project Financial Close (rather running in parallel during construction) are driving entry lags. More importantly, the new Rules are increasing fundamental project development risk profiles.

This latter issue is material. To be clear, the risk of an entrant needing additional assets or potentially being denied Connection makes the agreement of the Generator Performance Standards (5.4.3A) and resolution of system strength modelling and potential remediation (5.4.3B) an understandable condition precedent for Financial Close. The prospect of incurring greatly increased costs post-Financial Close and adversely affecting project economics is a newly emerging risk, and one that equity investors and debt financiers can no longer accept (i.e. prior to Financial Close).

This change to the Financial Close parameters of power projects is a new development in our market, and one that we have observed as a general trend from late-2018 onwards. It matters because it is making power project development significantly more challenging, and more expensive. That is, a power project needs to be fully developed (with specific turbines/equipment selected) and then held in suspended animation for period of ~6-7 months while Connection Agreements, Generator Performance Standards and Full Impact Assessments are completed. These processes involve at least four parties in a complex four-way negotiation process (i.e. project proponent, Original Equipment Manufacturer, NSP, AEMO). The process also brings forward a significant amount of detailed design work for a power project, with material capital commitments and expenditures prior to Financial Close. During the nominally 6-7 month period of 'suspended animation', project sponsors are exposured to changes in equipment pricing, exchange rates and the cost (and availability) of capital. All of these are material risks, the reasons for which are axiomatic. To compound matters, newly established projects are being subjected to new constraints as AEMO increases their modelling capabilities.

Together, even high value, flexible assets such as Batteries are becoming difficult to develop – not because of uncertainty over future revenues (always a part of project development) but because of fundamental Connection risk.

To be perfectly clear on this, changing the market design will not resolve any of these problems. The ESB should therefore look to:

- International experience on Connection;
- Whether the existing allocations of Connection risk and cost are appropriate, or whether alternative approaches for developing and/or funding centralised assets (e.g., Synchronous Condensers) might be more desirable – subject to a strict cost/benefit analysis in a manner consistent with the National Energy Objectives;
- How the need for a reliable, secure and resilient system can be balanced against the reasonable requirements of power project developments, and any consequential exposures consumers may face (i.e. avoiding gold plating).

2.2.2 Government interventions

Bespoke Commonwealth policies and interventions, no matter how well intentioned, can be expected to significantly increase the level of regulatory/policy risk regardless of market design. And when policy, regulatory and market interventions increase, it adversely affects sectoral investment planning and investment continuity. This occurs either via increasing the cost of capital (i.e. required returns to equity, and the cost, terms and level of debt offered by lenders[12]), or by freezing/crowding-out commercial investment commitments entirely:

- Underwriting New Generation Investment (UNGI) – historic evidence from the Qld region of the NEM is that when the State allowed Government Owned generators to invest in merchant plan, there was a perception (rightly or wrongly) that non-commercial / distortionary capacity commitments were being made, and this had the unintended effect of crowding-out legitimate private sector investment. That is why the Qld government subsequently made 'clear statements' and released policy documents in the late-2000s that GOCs were no longer able to invest in new generation plant. The risk of crowding-out private investment was *accepted logic* by the then Queensland Labor Government[13]. The Commonwealth's proposed UNGI scheme is inconsistent with this basic premise, and is at high risk of producing the same crowding-out effects.

- The "Big Stick" legislation appears to target three major utilities that have historically played an important role in reliability-related investments (given their dominant exposures to stochastic and weather-sensitive residential loads).

- Victorian Default Offer and Default Market Offer – vertical business combinations have been an historically important means by which to allocate risk efficiently, and regulated price caps - no matter how well intentioned, introduce genuine risks of random and capricious regulatory outcomes[14].

Reducing these barriers would require:

- All participating Governments to commit to no further off-market interventions beyond those orchestrated by COAG Energy Council;
- Providing firm commitments (to build, or not to build) proposed transmission and generation infrastructure, including Snowy 2.0;

---

[12] Given lenders have fixed returns with no upside.

[13] See Queensland Government (2010), "Shareholder review of Queensland government owned corporations", November 2010, Brisbane. Available at https://www.parliament.qld.gov.au/Documents/TableOffice/TabledPapers/2010/5310T3655.pdf

[14] See for example Simshauser (2014), "When does electricity price cap regulation become distortionary?", *Aust Economic Review*, 47(3): 304-323.

Simshauser, P. (2017), "Price discrimination in Australia's retail electricity markets: an analysis of Victoria and Southeast Queensland", *Energy Economics*, 62(2017): 92-103.

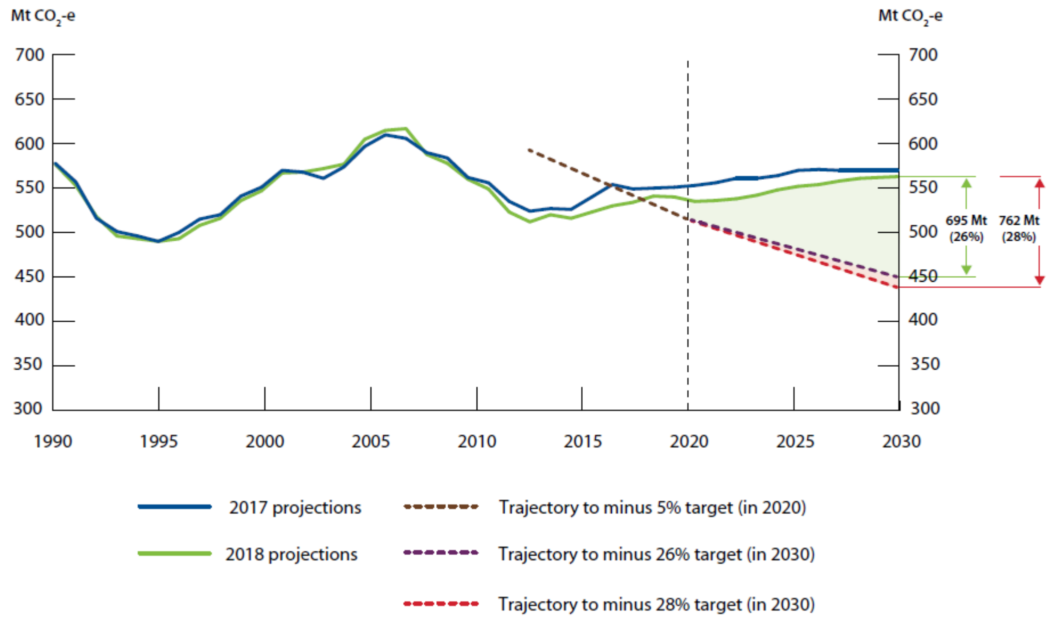
- The UNGI scheme to be put on hold until further clarity on private investment is achieved – noting that there are not forecast breaches of the Reliability Standard in the latest ESOO.

2.2.3 Policy uncertainty

NEM market participants do not need certainty over wholesale electricity prices – forward derivative markets exist to achieve a level of certainty that businesses require. But the lack of coordination between energy policy on the one hand, and on climate change policy designed to meet Australia's international CO_2 commitments on the other, does present certain problems for energy market participants.

The problem is that all market participants are able to access Figure 4 from the Commonwealth Government's "Australia's Emissions Projections 2018" document (reproduced below as Figure 6). This shows that more work is required to meet Australia's international obligations, and therefore, market participants *must* anticipate a future policy obligation designed to guide the economy to meet the targets – if not during the current term of government, then in some future term of government. In the absence of a price on CO_2 emissions, dis-investment, re-investment and investment decisions become more challenging to predict and coordinate in the post-2020 environment.

Figure 6 - Australia's CO_2 emissions trends, 1990 to 2030[15]



Providing certainty by way of intrusive policies will not foster investment continuity or necessarily improve reliability if those policies are fundamentally out of line with the

[15] See Department of Environment & Energy, (2018), "Australia's Emissions Projections 2018", Commonwealth of Australia, Canberra. Available at https://www.environment.gov.au/climate-change/publications/emissions-projections-2018

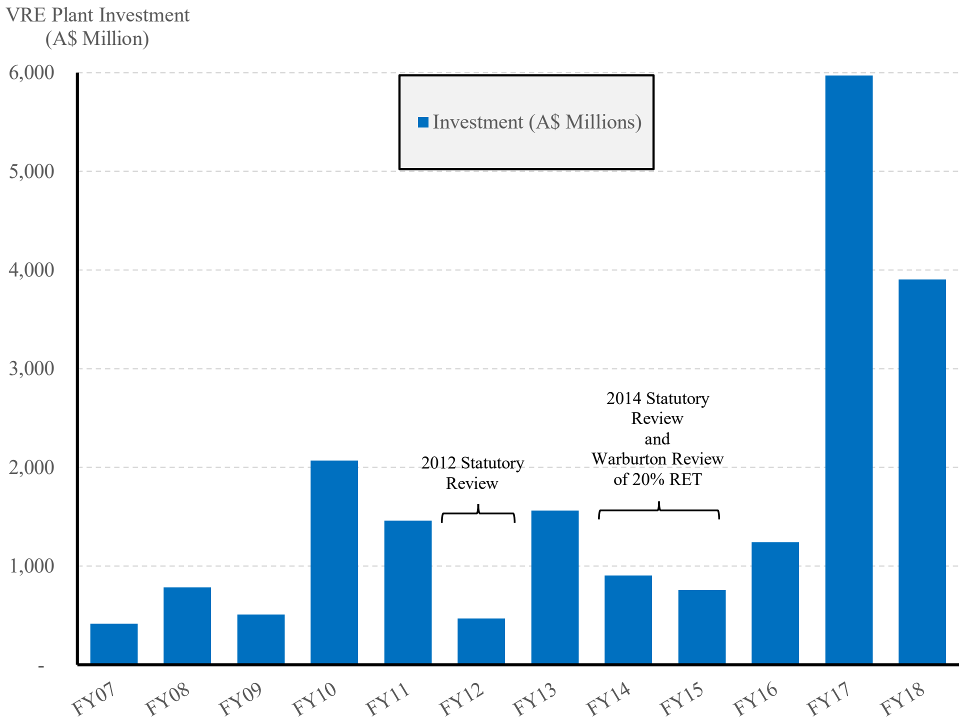
underlying market physics and market economics. Even if a 26% target for the NEM-only were legislated, participants will not have the investment signal to build low emissions technologies, and will still not invest in emissions-intensive generation.

2.2.4 The impact of significant market reform

The ESB is seeking to "ensure there is minimal disruption to the forward contract markets for electricity" arising from any market reform process. In our view, we do not believe this is possible under conditions of a materially changing NEM market design. Furthermore, it will almost certainly lead to two adverse side-effects:

1. Investment blackout – especially an institutional change extending over several years. The freezing up of market investments is well documented in other areas. Apart from the UK experience in the mid-2010s, Australia's 20%RET reviews in 2012 and 2014 had impressing effects on the flow of investment, as Figure 7[16] clearly illustrates; and

Figure 7 - VRE Investment Commitment vs RET Policy Reviews in 2012 & 2014



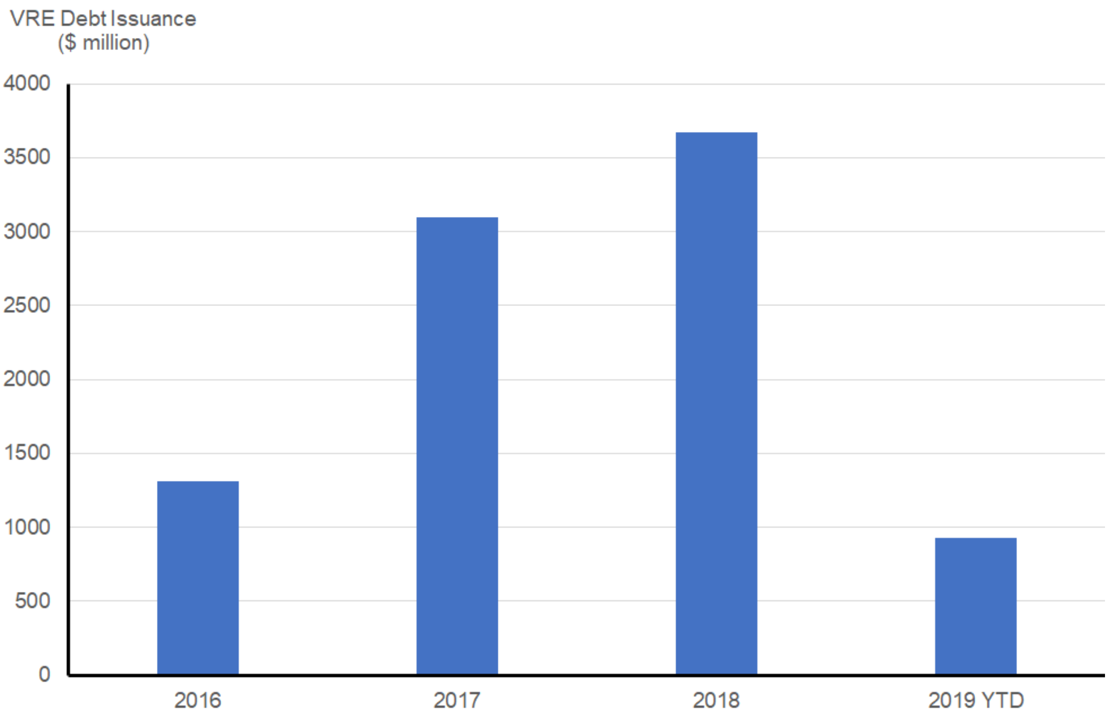
2. Potential defaults in existing financings of energy assets. An investment blackout not only adversely affects new investment, but it can extend to existing businesses vis-à-vis refinance maturing bullet and semi-permanent debt facilities on terms they may have reasonably expected (i.e. lenders don't

[16] For full details see Simshauser, (2019), Missing money, missing policy and Resource Adequacy in Australia's National Electricity Market", *Utilities Policy*, 60(2019): 100936.

want to roll over debt until they understand the new market operations from experience). Therefore, an institutional change may not only affect future investment, but may also affect the value and operations of existing assets. There are at least two potential high-risk areas. First, notably but not limited to project financings, where reasonably expected cash flows from generation may be disrupted as a result of market design changes. Secondly whether a fundamental change to the market design of the NEM constitutes a "Material Adverse Change" such that default may occur (which may depend on the effect of the change on the project at hand).

Figures 8 and 9 demonstrate that this is far more than a theoretical possibility. Figure 8 shows Project Finance / Debt Issuance associated with new NEM VRE asset financings over the period 2016 - 2019YTD. Debt issuance totals $9.01 billion across 92 projects with 11,767 MW of nameplate capacity.

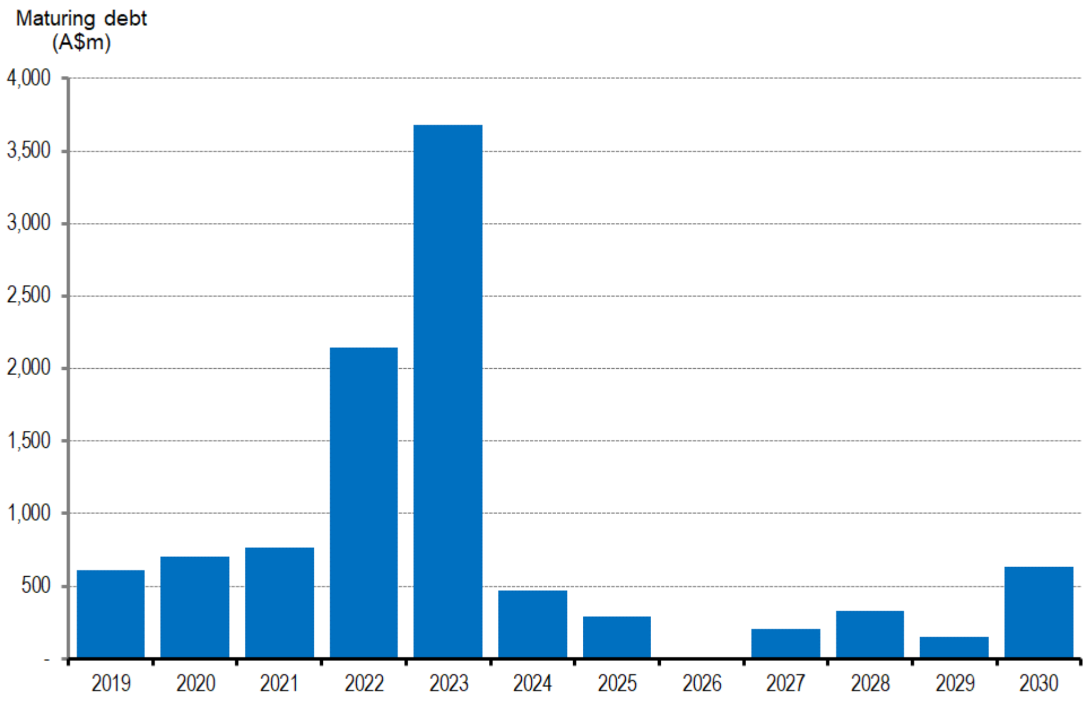
Figure 8 - NEM VRE Project Debt Issuance (2016 - 2019YTD)



Source: BNEF

More importantly is the tenor of facilities across the sector and the debt refinancing task facing the sector, illustrated in Figure 9. Note that 82.8% of all facilities outstanding, representing more than $7.75bn of project debt, need to be refinanced between now and 2025. Non-VRE power project debt then needs to be added to this amount (several $ billions more). This is clearly a crucial variable that needs to be considered with respect to post 2025-market design decisions.

Figure 9 - NEM VRE Project Debt Refinancing Task 2019-2030



Sources: Bloomberg, Company Websites, Media Releases, RenewEconomy.

2.3 Summary

A fundamental change to the market design is unlikely to reduce the specific headwinds that energy sector investment currently faces. If anything, a major redesign can be expected to increase them (recall Figure 7), and risks adversely affecting incumbent investments and their refinancing tasks (Figures 8-9).

The ESB has noted there are currently many disparate Rule changes seeking to reform key aspects of the market, including transmission investments, Demand Response and Frequency Control frameworks. Coordinating these rule changes would be a valuable role for the ESB.

3. MARKET REFORM OPTIONS: CAPACITY AND DAY-AHEAD MARKETS

Questions of market design are highly complex and have been debated extensively in both industry and academic literature. We encourage the ESB to consider a diverse range of sources, including academic research on market design with high VRE market shares, and practical evidence from the NEM. We note that while international research is important, there may be limited insights to be gained from markets which have not experienced high market shares of VRE and DER.

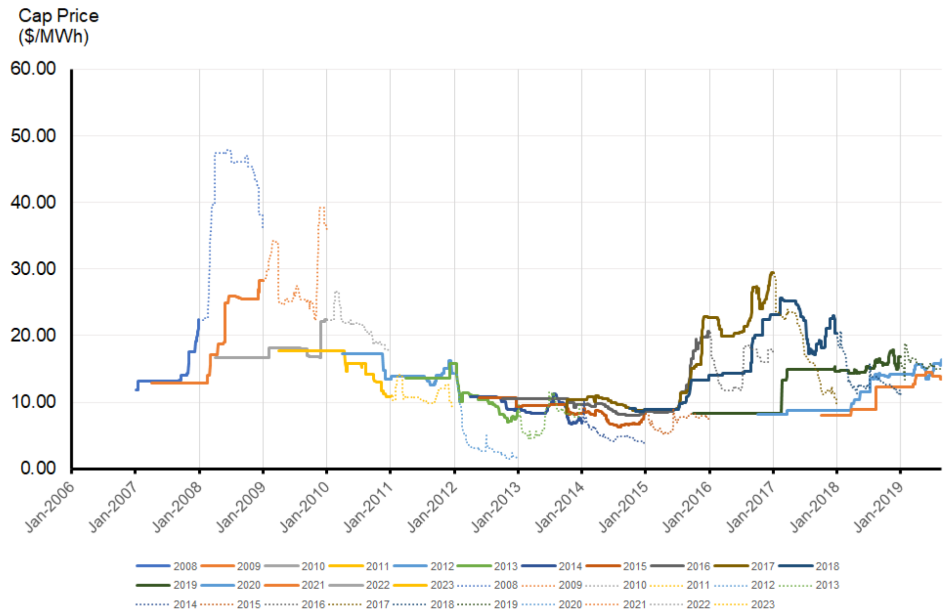
Infigen has reviewed and discounted two proposed reforms, viz. Day-Ahead Markets and Capacity Markets.

3.1 Capacity Markets

Several markets in the US, including MISO, PJM, ISO-NE, and NYISO, have organized Capacity Markets. As a general description, these are auctions that arrange for generation capacity to be available in, for example, three years' time. An Independent System Operator forecasts some measure of peak demand out for three years and solicits offers from both existing and proposed new assets to be available at peak periods (in three years' time). Generators that are successful in the auction are generally required to be available and offer into Day-Ahead and real-time markets during the future peak period.

Currently, the NEM does not have an organized Capacity Market but rather, has forward derivative markets for Swaps and Caps – with the quintessential link between physical (and spot market) requirements and new capacity being the relationship between the Reliability Standard (0.002% USE) and the prevailing Market Price Cap ($14,700/MWh). Figure 10, which presents $300 Caps from the SA region (2008-2023), shows that there is a clear and transparent value for Capacity in the NEM.

Figure 10 - Base Cal-Strip $300 Cap Prices – South Australia (2008-2023 Vintages)



A key difference between organized Capacity Markets and the NEM's forward markets is how the risk and cost of errors relating to over-capacity are allocated. In Capacity Markets, errors by the Central Planner are borne by (captive) consumers whereas in the NEM, sophisticated energy market investors bear the cost of errors.

The following sections discuss various aspects of organized Capacity Markets. We do not find value in implementing Capacity Markets for the NEM, given the significant differences between the emerging NEM and historical international systems.

3.1.1 Missing money

Missing money is the term given to the situation where electricity markets do not generate sufficient revenue to fund adequate investment to meet the Reliability Standard. This particularly applies to electricity markets where:

i. clearing prices are limited by an arbitrarily determined Market Price Cap much lower than the Value of Customer Reliability;

ii. stringent expectations exist for generation assets to bid generation at their marginal running cost up to rated capacity, and

iii. there is little or no price-based revelation of demand willingness-to-pay.

These conditions do not apply to the NEM. Price Caps in the US (outside of ERCOT) are typically around US$1,000/MWh which is far below the NEM Market Price Cap of $14,700/MWh. Moreover, there is no obligation for strict marginal cost bidding; it is generally accepted that some level of bidding above marginal running cost is acceptable given historically limited frictions to entry. Finally, there is a growing number of price responsive customers, and AEMO and AEMC are both working towards growing and integrating further demand response. To summarize, the three main drivers relevant to missing money in the US are not relevant to Australia's NEM.

The ERCOT market in the US shares more similarities with the NEM. It has a Market Price Cap of US$9,000/MWh, no organized Capacity Market, and an "Operating Reserve Demand Curve" (ORDC) based on the pioneering work of Hogan (2006, 2013) [17] in the field. The ORDC has the effect of administratively setting market prices to a higher level when supply is tight without relying on generation bids above marginal running costs.

Reserve margins in ERCOT have been tight in recent years. However, elevated price volatility together with retail restructuring have begun to encourage various (price-based) demand-side responses that reduce the aggregate demand function during tight supply conditions in response to the ORDC-induced high prices. It is important to understand that this brings ERCOT closer to the ideal of a two-sided market than any other electricity market in the US. That is, ERCOT approximately emulates the outcomes of a competitive market with active demand-side bids. The natural further improvement in such a market is not the addition of an organised Capacity Market, but rather, increased participation by the demand-side.

---

[17] See Hogan, 2005. "On an 'Energy-Only' Electricity Market Design for Resource Adequacy". Centre for Business and Government, John F Kennedy School of Government, Harvard University.

Hogan, 2013. "Electricity scarcity pricing through operating reserves", *Economics of Energy & Environmental Policy*, 2(2): 65-86.

Conclusions

Higher VRE market shares may eventually require a higher Market Price Cap[18], or the inclusion of an ORDC with a lower Market Price Cap, and the expansion of FCAS market services. Furthermore, incorporating “willingness-to-pay” and moving closer to an ideal two-sided market whilst maintaining a tight nexus with the prevailing Reliability Standard undercuts any perceived need for an organised Capacity Markets to solve missing money and Resource Adequacy problems.

3.1.2 Assurance that generation capacity will be available when needed

Organised Capacity Markets are predicated on an Independent Market Operator making and committing to a forecast peak demand several years in advance. This inevitably requires the Market Operator to take over roles in forecasting economic outlooks – a role more properly assumed by the collective actions of risk-seeking, sophisticated utility sector institutional investors.

Organised Capacity Markets allocate the risks of excess capacity to captive consumers. Conversely, they do not avoid the risk of underinvestment – although we acknowledge organized markets tend to experience oversupply rather than undersupply. But in our view, contemporary reliability (and security) related events in the NEM would not have been defused by the existence of an organised Capacity Market. Significantly, neither the Northern[19] or Hazelwood[20] closures were anticipated in AEMO’s ESOO publications even one year out from these events.

Any risk of long-term insufficient capacity can be attributed to a breakdown in the nexus between the Market Price Cap and the Reliability Standard - something which as outlined earlier his little practical history in Australia’s NEM. Thus on a look-back basis, it seems unlikely that a market redesign would have resulted in different physical outcomes unless a central procurer purchased a significant oversupply of plant capacity, the cost of which would ultimately be passed on to consumers. Conversely, there is evidence that Market Operators are inclined to be more conservative, over-procuring capacity and increasing long-term costs to consumers[21].

---

[18] See for example Riesz, Gilmore & MacGill (2016) “Assessing the viability of Energy-Only Markets with 100% Renewables”, *Economics of Energy & Environmental Policy*, 5(1): 105-130.

[19] https://www.aemo.com.au/-/media/Files/PDF/2015-Electricity-Statement-of-Opportunities-Update.pdf

[20] No reliability issue identified in Victoria, although 1600 MW of brown coal withdrawn in some scenarios. https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NEM_ESOO/2016/v2/2016-Electricity-Statement-of-Opportunities-Report_V2.pdf

[21] See Newberry, (2016), Missing money and missing markets: reliability, capacity auctions and interconnectors”, *Energy Policy*, 94(2016): 401-410.

3.1.3 Defining capacity

Designing an appropriate set of specifications for "Capacity" in organized Capacity Markets has proved exceedingly difficult and without global consensus[22]. The protracted development of the Retailer Reliability Obligation (RRO) guidelines (where even Draft Guidelines were not finalised before the RRO became law) demonstrates this point. There is no longer a clear definition of "Capacity", and any attempts to impose a centralised and limited definition will necessarily stifle flexibility and investment.

Instead, portfolios of assets and contracts must be considered in their entirety. This is AEMO's approach to modelling for the ESOO: reliability is ultimately a *system* outcome and requires a probabilistic approach. Deterministic approaches (e.g. procuring a certain number of MW) becomes even less relevant with higher market shares of VRE and energy-limited resources including energy storage, which is where the NEM is evidently heading.

International reforms of organized Capacity Markets have focused requirements in such a way as to ensure payments are only made if generators were producing when required (i.e. at times of tight supply—demand balance). This is precisely what is delivered under an energy-only market, with far less administrative complexity.

3.1.4 Avoiding the premature closure of a particular asset class

A third motivation in the US for organized Capacity Markets has been to avoid the premature closure of large, central nuclear and coal plants. Without arguing specific pros and cons of such a strategy, much of the existing coal capacity in the US is quite old and operationally inflexible. But organized Capacity Markets may incentivise an incorrect asset allocation if designed to maintain specific assets and excludes physical requirements of the system, such as ramp rate capabilities and starting profiles.

Note that organized Capacity Markets have *not* prevented the closure of nuclear and coal plants in the US. Between 2010-2019, 529 coal units comprising 77,000MW of nameplate capacity had exited US markets, with the average plant age at closure being 54 years. Similarly, 7 nuclear units comprising 5320 MW had exited (average plant age 41 years) although due to various idiosyncratic issues.

In contrast, in the 133,000MW (nameplate capacity[23]) ERCOT system, the only US market with neither an organized Capacity Market nor a Statutory Reserve Requirement (e.g. Retailer Reliability Obligation), there are four nuclear plants that

---

[22] See Byers, Levin and Botterud (2018), Capacity market design and renewable energy: Performance incentives, qualifying capacity, and demand curves, *The Electricity Journal*, 31(1): 65-74.

[23] Comprising 78118 MW gas-fired generation, 20444MW coal plant, 24581MW wind, 1943MW solar PV, 709MW hydro, 7243MW other.

are not apparently in danger of closure, and only 4979MW of the 25,422MW coal plant fleet has exited.

It is also notable that Singapore has sought to introduce an organized Capacity Market in response to a significant oversupply of generation and low wholesale prices[24], risking propping up inefficient investments at the cost of consumers; Singapore also features a very high reserve margin which would be costly for consumers[25].

3.2 Day-Ahead Markets

All of the centralized markets in the US (CAISO, ERCOT, SPP, MISO ISO-NE, PJM, NYISO) have both a real-time market and a Day-Ahead market. There are various specific differences between the designs in these markets. The following discussion will focus on generic characteristics common to most or all. Some of the real-time markets, such as CAISO, MISO, PJM, and NYISO, have look-ahead commitment and/or dispatch which involves consideration of the upcoming dispatch interval and intervals into the future. Other markets, such as ERCOT and SPP, do not have look-ahead.

Current implementations in the ERCOT and SPP markets have similarities to Australia's NEM. For example, all three markets have 5-minute dispatch intervals and generators are dispatched individually through signals from the respective Market Operator, i.e. ERCOT ISO, SPP ISO, and AEMO, respectively. Transmission constraints are represented in the dispatch algorithm in each market.

While the NEM does not have a formal Day-Ahead Market, it *does* deliver similar services. The NEM has a 40-hour pre-dispatch schedule that is continuously updated by reference to generator bids made in good faith, a liquid forward market such that most capacity is contracted, and AEMO has opportunities to intervene if conditions change rapidly.

The following sections explore specific aspects of Day-Ahead Markets in the NEM.

3.2.1 Financial hedging

In relevant US markets, market participants seek to reduce exposure to highly volatile real-time markets by offering or bidding into Day-Ahead Markets. Real-time prices are still applied to differences between real-time positions and Day-Ahead positions, and thus some spot exposure remains regardless of a Day-Ahead Market.

Infigen sees some merit in the development of an organized (voluntary) OTC/Exchange Day- to Week-Ahead Contract Market, similar to AEMO's proposed

---

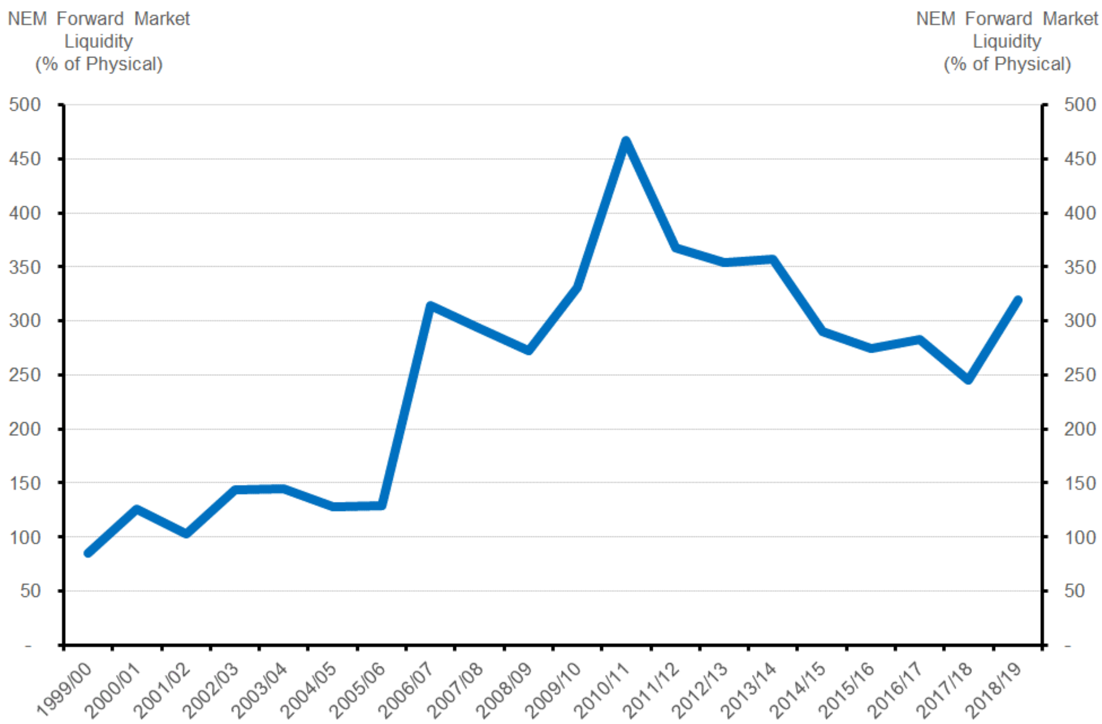
[24] https://www.emcsg.com/f279,137167/NEMS_Market_Report_2018_FINAL.pdf

[25] http://www.aperforum.org/files/Theme_3_4_Singapore.pdf

STFM, thereby providing participants with increased options for adjusting financial positions closer to real-time.

However, the value of additional hedging in Day Ahead Markets is questionable from a NEM entry perspective. Entry and ongoing operations requires longer-dated certainty for the bulk of revenue streams in order to meet project banking constraints and shareholder preferences[26]. The NEM's forward markets (i.e. with tenors of 1 Quarter to 3 Years in the futures market, and nominally 1 day to 15 years in the OTC markets) remain the primary source of hedging for market participants. As Figure 11 notes market liquidity in the NEM is currently running at ~300% of physical trade, meaning that each MWh has been bought & sold the equivalent of *~3 times* before it has been consumed.

Figure 11 - OTC & ASX Forward Electricity Market Liquidity 1999-2019[27]



[26] See for example Joskow, P. 2006, "Competitive electricity markets and investment in new generating capacity", *AEI-Brookings Joint Centre for Regulatory Studies*, Working Paper No.06-14.

Simshauser, P. 2010. Vertical integration, credit ratings and retail price settings in energy-only markets: Navigating the Resource Adequacy problem. *Energy Policy, 38*(11), 7427-7441.

Caplan, E. 2012. What drives new generation construction? an analysis of the financial arrangements behind new electric generation projects in 2011. *The Electricity Journal, 25*(6), 48-61.

Nelson, J. and Simshauser, P. 2013, "Is the Merchant Power Producer a Broken Model?", *Energy Policy,* 53(2013): 298-310.

[27] Sources: Simshauser, Tian, Whish-Wilson (2015), "Vertical integration in energy-only electricity markets", *Economic Analysis & Policy*, 48(2015): 35-56.

Nelson, Pascoe, Calais, Mitchell & McNeill (2019), "Efficient integration of climate and energy policy in Australia's National Electricity Market", *Economic Analysis & Policy*, 64(2019): 178-193.

Accordingly, a Day-Ahead Market is most unlikely to generate any material advantages to new entrants over and above existing opportunities for hedging.

3.2.2 Providing assurance that adequate generation resources will be available for the next day

The previous section highlighted financial hedging. As a general principle, financial positions do not imply physical availability, although it is reasonable to expect that a generator that takes on a financial position (in either the OTC or futures market) will make itself available in the real-time market to avoid or manage exposures to high spot prices.

Since Day-Ahead financial markets (by themselves) do not provide absolute assurance about generation availability, other mechanisms are necessary to communicate availability to Market Operators. Although the details vary from market to market in the US, in ERCOT for example, generation assets must specify their actual plans to be in-service in their "Current Operating Plan" provided to the Independent System Operator. Similarly, such assurance to AEMO is provided through the 40-hour pre-dispatch and short-term PASA processes. Consequently, a Day-Ahead Market will not provide any more assurance to AEMO of generation plant availability.

A physical commitment Day-Ahead Market would be a radical and likely inefficient departure from NEM operations and conflicts with the drive for more flexible resources (e.g. the 5-Minutes Settlement rule change). Participants require the flexibility to select least-cost resources as better information is available closer to real-time.

To the extent that existing markets (energy and FCAS) do not provide sufficient signals for other reliability or security services (e.g., ramp rates, spinning or non-spinning reserves), this should be addressed through the creation of new FCAS markets for newly defined ancillary services. Additionally, these products or services should be priced rather than directed by AEMO – and may be procured through organized spot markets, tender-based contracts, or provided by way of regulated service in line with the National Electricity Objective.

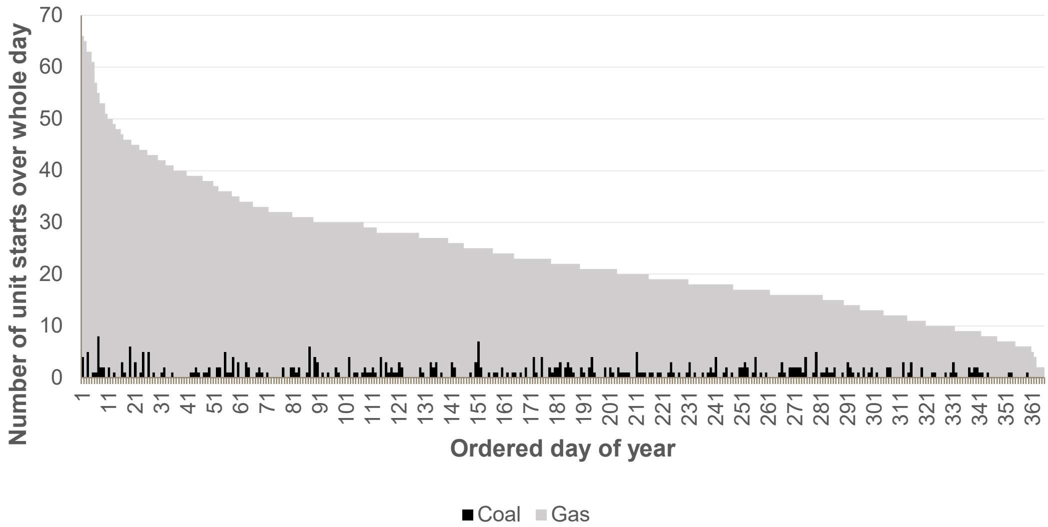
In summary, it is not at all clear that there is value in establishing a Day-Ahead market for dispatch given the greater information available closer to real-time. We elaborate on this point below.

3.2.3 Commitment and cycling of slow-start generation plant

Presently, almost all coal units run continuously and are not making unit commitment decisions on the day. Figure 12 contrasts coal unit commitments against gas unit commitment decisions. Two shifting (e.g. cycling over the midday off-peak period) may become more common amongst the marginal plant in future as coal units receive price signals (including negative prices) to be more flexible. Internationally, weekend decommitments are typically viable.

However, given emissions constraints it seems more likely that capacity provided by the marginal unit may be replaced by more flexible dispatchable plant such as fast-start Gas Turbines, Batteries and Pumped-Storage Hydro with only a small number of coal units making cycling decisions. AEMO's 2019 ISP may be able to provide greater insights.

Figure 12 - Generation plant unit commitment decisions in the NEM (2018-19)[28]



For most participants, fuel (if applicable) can be secured on the day, albeit usually at higher cost. This is a decision best managed by market participants who may purchase and "park" fuel as a risk management strategy, for example.

Infigen's Operations Control Centre continually monitors pre-dispatch price forecasts *including sensitivities* to make unit commitment decisions at our Gas Turbine units. Similarly, Infigen's Battery (connecting October 2019) will use software to continually determine bidding and operating strategies with the highest expected revenue. This is generally true for all market-facing participants.

[28] Multiple starts of the same unit are counted as multiple starts within the day

3.2.4 Energy-limited resource scheduling

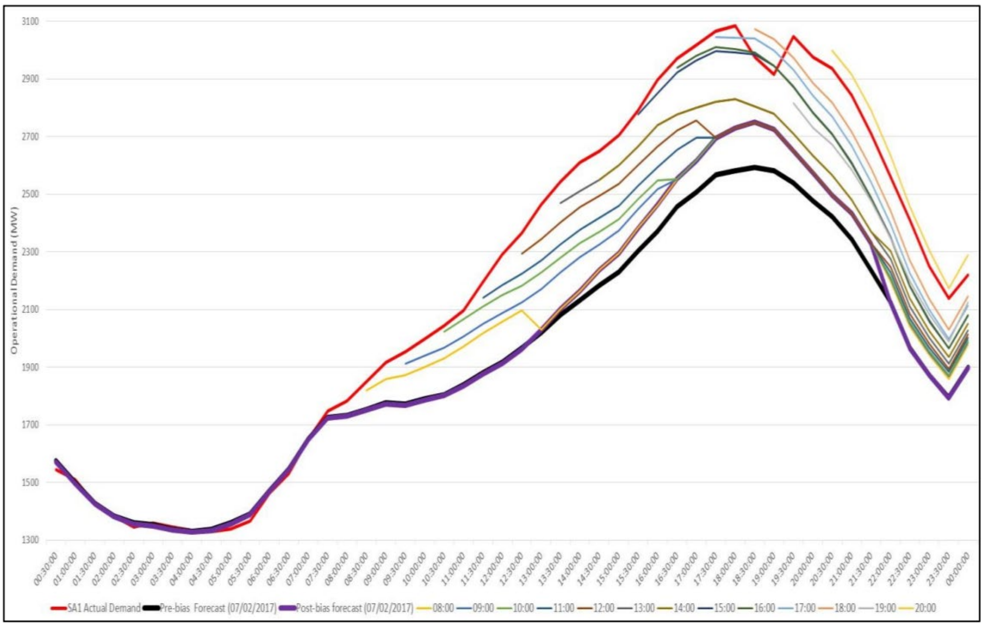
For energy storage systems sized to match daily or weekly needs, there is value to coordinating such resources with thermal production because the value of the stored energy (i.e. pumped-hydro / battery) is dependent on the opportunity cost of generating and pumping/re-charging over time. However, similar to the issue with coal plant unit commitment, a daily scheduling horizon may not be long enough to make economically relevant decisions when weekday—weekend consumption patterns drive the storage scheduling.

3.2.5 What problems can Day-Ahead markets address?

To date, the NEM's real-time spot market has correctly responded to pre-dispatch information provided by AEMO to the extent that this information is accurate. Infigen is not aware of historical examples where centralised, Day-Ahead, physical unit commitment would have led to improved on-the-day reliability outcomes. For example:

- On the 8th February 2017 load shedding event, after temperatures continually exceeded forecasts with a corresponding increase in demand, load shedding occurred in the evening (Figure 13). However, no shortfall was identified until 3pm on the day (LOR1 event called for 1630-1900)[29].

Figure 13 - Operational demand forecasts updated through the day (February 8th 2017)[30]



[29] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/System-Event-Report-South-Australia-8-February-2017.pdf

[30] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/System-Event-Report-South-Australia-8-February-2017.pdf

- On the 10th February 2017 load shedding event, very high demand with coincident unit outages resulted in load shedding to maintain system security. The Colongra Gas Turbine plant was unable to start at a critical time due to low gas pressure in its pipeline. Infigen understands that the units expected to be able to run but were unable to start; from the publicly available information, it is not clear whether a centralised approach would have resulted in different dispatch decisions. AEMO did not issue any directions to generation during the day.

- On the January 24th and 25th 2019 load shedding events, coincident high demand and generator outages led to load shedding (despite RERT activation). AEMO did not direct any generation, nor identify any generators that could have been available had different (e.g., centralised) decisions been made day-ahead[31].

- AEMO did not identify any poor unit commitment decisions or day-ahead errors contributing to the Queensland and South Australia system separation event on August 25th 2018[32].

- In response to the Black System South Australia event, AEMO recommended changes to how risks are assessed and how the grid should be managed, but did not identify any poor unit commitment decisions[33].

3.2.6 Alternatives to Day-Ahead Markets

It seems unlikely that a centrally controlled Day-Ahead Market *alone* would result in materially different outcomes – rather, a Day-Ahead Market would be one way of centrally controlling a future requirement for greater reserves to be available. However, a central dispatch process is not the only (nor necessarily the most efficient) means of achieving such an outcome.

One option would be increased information. AEMO has recently developed a Forecast Uncertainty Measure (FUM) that uses a sophisticated Bayesian network to predict the range of potential supply and demand scenarios up to 60 hours ahead. AEMO may, in the future, require more sophisticated pre-dispatch simulations that consider more "holistic" scenarios across the day (e.g. evaluating reserves under

---

[31] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2019/Load-Shedding-in-VIC-on-24-and-25-January-2019.pdf

[32] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2018/Qld---SA-Separation-25-August-2018-Incident-Report.pdf

[33] https://www.aemo.com.au/-/media/Files/Electricity/NEM/Market_Notices_and_Events/Power_System_Incident_Reports/2017/Integrated-Final-Report-SA-Black-System-28-September-2016.pdf

lower midday demand *with* higher evening demand) regardless of whether a centralised or decentralised response was expected.

Historically, the market has responded to AEMO's Lack of Reserve notices, typically by making additional generation available. In the future, it is conceivable that the risk and/or cost of making additional capacity available is higher. For example, a coal unit might need to run through negative price periods for a possible, but unlikely, Market Price Cap event in the evening. An equivalent scenario might be for coal units to run through low price periods due to expected and material evening ramp rate constraints.

In either circumstance, there may be a role for AEMO to develop spinning, non-spinning reserve or ramping markets in a manner similar to existing Contingency FCAS markets, albeit with slower response times (e.g. 30 minutes). To the extent that there is a cost associated with making reserve capacity available (e.g. securing coal or gas fuel, running units at minimum load, etc.) such FCAS markets may provide an efficient direct cost recovery mechanism to supplement expected (statistical) revenues.

An alternative option may be to adopt Hogan's ODRC approach – either would be at least as effective without introducing a dramatic regulatory and policy disruption on the market associated with changing from a real-time spot market (with a 20-year institutional history) to a Day-Ahead Market.

Infigen can see value in facilitating a voluntary Day- to Week-Ahead Contract Market similar to AEMO's STFM concept. Such markets may help participants to fine-tune forward positions, energy storage, VRE and peaking plant outcomes.

4. SPECIFIC RESPONSES TO ESB SUBMISSION QUESTIONS

Infigen has provided some specific responses below, and has also provided some further suggestions in Appendix A.

What scenarios and shocks should be used? How should these be used to test market design?	On a forward-looking basis, key market shocks need to be specific, quantitative in nature and within the envelope of possibility given the existing system. Shocks might include rapid plant closure at scale (which as an aside, no pre-existing market design globally can prevent in the absence of bespoke intervention - or over-rides Corporations Law obligations including those associated with insolvent trading), evening ramping limits, emerging system security constraints, and rapid growth of VRE / DER in remote or skinny parts of the transmission network (such as far north QLD) The ESB should also identify emerging trends in the market, building on the ISP modelling,

	AEMO's Renewable Integration Study, AEMO's DER work program and other projects.
How can market and economic modelling best be used to evaluate individual components of market design or the end-to-end market design?	In the first instance, the ESB should provide case studies – demonstrating scenarios where (for example) the existing market design would be unlikely to achieve an efficient outcome. These should be based on quantitative modelling, but need not include (for example) detailed time series modelling. For example, the ESB might present a scenario where pre-dispatch would not deliver an effective outcome but an ahead market would.
Is the assessment framework appropriate to evaluate the effectiveness of future market designs? What else should be considered for inclusion in the assessment framework?	The framework is appropriate, but the greatest weight should be given to not disrupting investment at a critical time in the NEM.
Have we identified all of the potential challenges and risks to the current market? If not, what would you add?	The list is generally appropriate. Infigen notes that the greatest challenge for connecting generation is not "firm" access to transmission (indeed, Infigen does not consider this has been a barrier to date) but rather the delay and risk in obtaining connection agreements.
Which of these challenges and risks will be most material when considering future market designs and why?	Appropriate price signals and procurement strategies for system security services (including system strength) and DER are the major services not currently priced.
Which (if any) overseas electricity markets offer useful examples of how to, or how not to, respond to the challenges outlined in this paper?	While insight into international markets is helpful background (particularly the Irish markets), Infigen cautions that Australia is at forefront of integrating VRE and has very particular physical market characteristics. All markets have experienced historical stresses and, conversely, most markets (including the NEM) have functioned effectively – therefore, caution should be taken in interpreting the merits of each market.

5. CONCLUSION

Critical to the functionality of the power system as a whole is maintaining the confidence of both debt and equity capital markets if the requisite future investment in generation plant and network plant is to occur. Direct and random interventions by government to either support particular generation projects/technologies, to reverse commercial decisions of owners of existing assets, or worse still – make commercial decisions instead of allowing market participants to do so – dramatically heightens perceptions of sovereign risk. If perceptions of sovereign risk are heightened, it will invariably lead to (efficient) investment discontinuity. Relying on government to invest or underwrite power generation has a very long history of producing higher overall system costs through inefficient and/or poorly located investments.[34] The implications for producers and consumers is material welfare losses.

On power system design, moving away from an energy-only market would be a multi-year project that can only increase uncertainty in the near-term, threaten the ability of the market to transition adequately, and pose material problems for asset refinancings and new entry in future periods.

As demonstrated by Infigen's recent investment in wind, battery and peaking generation, at its core the NEM remains highly investable and we do not expect this to change. Many of these merchant investments have also occurred in the highest VRE region – SA. In the absence of identifying specific challenges or quantifying how and why they cannot be met under the existing design, we see large-scale change as a "net negative".

We look forward to the opportunity to continue to engage on this matter. If you would like to discuss this submission, please contact Prof Paul Simshauser or Dr Joel Gilmore on 02 8031 9900.

Yours sincerely,

Ross Rolfe
Managing Director

[34] See for example Simshauser (2005), "The gains from the microeconomic reform of the power generation industry in East Coast Australia", *Economic Analysis & Policy*, 35(1-2): 23-43.

APPENDIX A

The Table below highlights some of the existing and emerging issues that the NEM is required to respond to. Infigen has provided some commentary on how the NEM could adapt, if needed, in the future to more efficiently deliver the service.

Emerging challenges	Current management in the NEM	Future management options in the NEM
Increased but *forecastable* ramps in net loads **E.g., based on demand minus solar PV shape – a predictable change**	Managed through pre-dispatch forecasts and 5MinDispatch. Participants recognise that a lack of flexible capacity online will drive prices higher	Pre-dispatch will continue provide clear price signals to market participants to prepare for forecasted evening peaks. This will include coal generation either developing two-shifting capability, or remaining online over low price midday periods to earn evening peak revenue.
***Unforecasted* fast ramps in net loads (within 5 minutes) – driven by changes in load or VRE**	Managed through Contingency FCAS or Regulation FCAS	May require greater FCAS reserves or revised FCAS services (e.g., fast frequency response) but otherwise existing framework should remain suitable. Better DER controllability or reviewed causer pays framework could help reduce requirements and hence costs.

***Unforecasted* slow ramps in net load (e.g., over 5min-2 hours)** **Could be driven by unexpected changes in bulk supply or demand (e.g., within a few hours of real time)** **Increased uncertainty over forecasts** **Seen through greater Forecast Uncertainty Measure (FUM)**	Sufficient dispatchable capacity is currently available that pre-dispatch and 5MD are sufficient. No ramping issues have been identified. AEMO presently uses the Forecast Uncertainty Measure (FUM) to estimate the potential uncertainty in both demand and supply. This is then compared to the *available* capacity in each trading interval through pre-dispatch. If a shortfall is identified (e.g., insufficient capacity could be dispatched to meet a higher than expected demand or lower than expected wind) then AEMO declares a Low Reserve Condition and seeks a market response. Participants will seek to manage their risk through physical or financial (backed by physical) products.	Larger ramps (e.g., unexpected weather events causing gradual solar drop-off) could become more material. Conversely, more fast-ramping generation is likely (batteries, dual fuel peakers, pumped hydro, etc.) Risks likely to be managed by participants: any risk of Market Price Cap (MPC) is still material; AEMO could potentially increase transparency by considering more explicit “daily” pre-dispatch scenarios – e.g., lower than expected midday demand and higher than expected evening demand – *if* those are credible scenarios. But note that this would be required regardless of market design (and, indeed, be even more necessary with centralised control. However, if risk cannot be managed could be role for new market to de-risk provision of reserves. E.g., some form of spinning or non-spinning reserve – e.g., a “30 minute FCAS”/ramping ancillary service where providers are required to make themselves available within 30 minutes on request from AEMO (e.g., triggered by an LOR call). This would reduce risk for participants in holding capacity in reserve. Procurement volume could be based on FUM (or even published day-ahead), or a fixed volume could be determined; usually priced at zero given plenty of fast ramping capacity. Alternatively, could escalate prices when reserves are low to provide price signal for availability. Day-Ahead markets don’t seem well suited: these are about locking in *fixed output*, rather than *preserving optionality*. Issues are more likely to occur over shorter timeframes and ahead markets do not necessarily reserve headroom (although could deliver this in conjunction with a non-spinning reserve service)

"Peakier" net demand, resulting in resources (for example) required for only one hour every year (or even less)	The Reliability Panel considers these issues in evaluating market setting to meet the reliability standard, including setting the critical input, the MPC. To date, the reliability standard has been met in almost every year. In the even that AEMO predicts the reliability standard will not be met, the Retailer Reliability Obligation provides a long-term mechanism for securing capacity and the RERT a short-term one.	An efficient market might in the future require raising the MPC. Clear processes are in place for this. Continued evaluation of reliability standard and value of customer reliability. Encouraging greater demand side participation important to minimising costs – as noted by AEMC in their DRM Draft Decision, should work towards a true two-sided market.
Persistent but random **government intervention**	Most recent investments have been influenced by government intervention (SA battery, renewable projects, etc.) However, market drivers still generally influenced which projects & where. E.g., LRET dictated volume of renewables, but not which projects. State-based CfDs similar. Hornsdale battery impacted business case for Riverlink and private investment that might otherwise have occurred. UNGI & Snowy 2.0 threatens private investment	Governments should provide frameworks that factor in externalities without attempting to pick winners in an otherwise competitive market. (E.g., emissions targets or carbon prices, but not technology specific targets)
Exit of synchronous generation	3 year notice of closure rule change provide some protection against unexpected closures. Vertically integrated participants have strong incentive to replace their capacity at end of life and maintain market share. However, political pressure may make this less attractive.	3 Year Notice of Closure should be *binding* to provide certainty, subject to resolving insolvent trading constraints. That is, neither participants nor government intervention should be able to stop the unit exiting the market. Units can apply for RERT beyond that period *if* a shortfall is identified. Critical that AEMO has a plan for managing inevitable exits, rather than prevent the exit if it is economically efficient. Could consider a long-term "N-1"-equivalent planning standard for syncons/system security – ensuring that the closure of any single unit/station will not cause disruption.

		Need to consider procurement – network, market, contracts, etc.
Load forecasting becoming more challenging (e.g., Embedded DER/DR is less visible, and can impact on forecastability)	AEMO operating a DER registry of price responsive loads DR rule change to require some DR to be scheduled	Seek greater visibility of DER
Accuracy of VRE forecasting	AWEFS and ASESFS – AEMO providing forecasts on a centralised basis	AEMO is undertaking a self-forecasting trial, looking for potential forecasting improvements.
Controllability of DER	Increasing issue – every additional DER system (e.g., rooftop solar) installed without remote monitoring & control makes the future problem & solution harder.	AEMO and AEMC are exploring operational limits and potential solutions.
Energy storage registration	Storage currently registers as both a load and a generator – ignoring underlying physics of the single unit.	Being addressed by AEMO rule change, proposing a new registration category – should make procuring and managing ancillary services easier.
Coordination of energy storage operation – batteries will tend to all discharge on first high price period rather than completely shaving peak	Batteries are free to charge or discharge as deemed commercially viable. AEMO has imposed ramp rates on energy storage to minimise disruption.	Market participants should continue to maximise revenues and allocate dispatch into highest revenue periods. There is some risk that once the price reaches the Market Price Cap, temporal signals for battery dispatch are muted. A spinning, non-spinning or ramping ancillary service would reduce the risk of deferring battery dispatch. Alternatively, there are options for multi-period dispatch engines. A more sophisticated ST-PASA system may be required.
Increased penetration of low marginal cost generation	Merit order effect impacts existing coal, peaking units relatively unaffected, renewables also see merit order effect but somewhat insulated through LGCs	Not a fundamental change – cf entry of Hazelwood drove down prices closer to marginal cost. For new VRE, a simple lack of revenue under an energy-only market would indicate that further investment not needed (or, rather, a different technology/location is required). Expect that curtailment becomes more common – “overbuild” to meet demand in peak periods and curtail offpeak, similar to oversizing the DC vs AC components of

		solar PV. This is an efficient outcome, i.e., not a market failure.
Revenue adequacy – baseload units	Energy-only market with reliability standards closely aligned to the Market Price Cap	Baseload energy providers will be progressively less valuable over time – appropriate market signals for exit.
Revenue adequacy – peaking units	Energy-only market with reliability standards closely aligned to the Market Price Cap	The energy-only market provides strong signals for peaking capacity. Revenue could become more volatile – or peakers could be more regularly used. Requires liquid forward market for caps to manage risk; this requires limiting market interventions. Incentivising extreme peakers might require raising the Market Price Cap, markets for reserves or ramping, or increasing prices during tight supply demand periods.
Revenue adequacy – batteries	Energy-only market with reliability standards closely aligned to the Market Price Cap	Energy-only market will continue to provide strong signals for arbitrage Greater participation and interaction with FCAS markets likely
Revenue adequacy – VRE	Energy-only market with reliability standards closely aligned to the Market Price Cap, LRET, CfDs, corporate PPAs	Revenue may be concentrated in small number of periods and strongly depend on performance during “low VRE” periods. Strong forward market required – may necessarily involve portfolios of VRE (+firming) and/or vertical integration to provide sufficient revenue certainty. Energy-only market will continue to value resources with good correlation with demand but also less correlated with other resources – i.e., can generate during tight supply-demand periods.