Ms Sara O'Connor
Economic Regulation Authority
Submission by email: publicsubmissions@erawa.com.au

08 February 2019

Dear Sara,

**RESPONSE TO DISCUSSION PAPER – REPORT TO THE MINISTER FOR ENERGY ON THE EFFECTIVENESS OF THE WHOLESALE ELECTRICITY MARKET 2017/18**

Summit Southern Cross Power Holdings Pty Ltd (SSCPH) welcomes the opportunity to provide comments on the above discussion paper. The ERA (Authority) annual 'Report to the Minister for Energy on the Effectiveness of the Wholesale Electricity Market' is a welcome initiative which continues to reflect on the changing circumstances of the electricity sector and encourage thought on how best to ensure the market keeps abreast of this change.

The discussion on pricing trends is well thought through, though the high-level observation would be that there is unlikely to be any 'smoking gun' driving up wholesale prices, rather; that a number of changes to the supply-demand paradigm are often in conflict with respect to price impact. There is also some conjecture about how much the wholesale price has actually increased in the WEM and the materiality of this.

The section on investment risks is very timely. The issues identified are numerous and difficult to resolve. Serious policy consideration should be given to this issue as decisions made now will have a material impact on the future physical and competitive structure of the WEM.

The issue of the increasing cost of market administration and governance – and the increasing complexity of what should be a relatively simple, small electricity system, can no longer be ignored. The question from here is: What should be done about it? To identify these issues and trends and allow them continue would be a failure of governance.

Should you have any questions regarding this submission please contact myself or Daniel Kurz on [redacted] or [redacted]

Yours sincerely

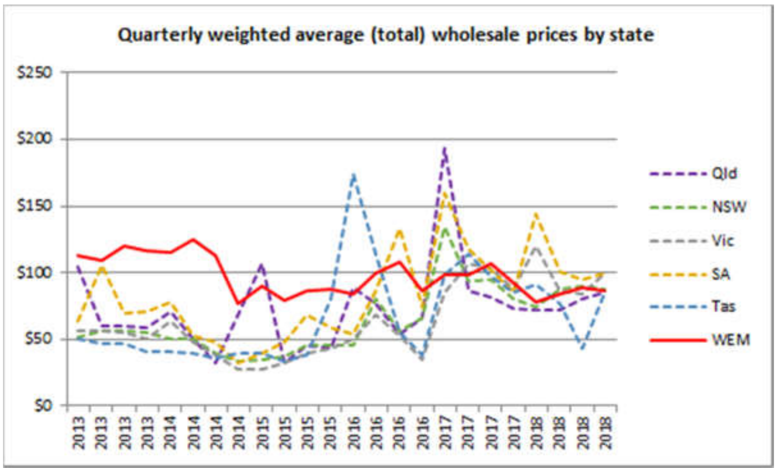
[redacted]

Shane Cremin
General Manager – Commercial and Strategy

Pricing trends in the WEM and potential drivers

The Authority has examined a number of potential causes for the wholesale price increases experienced in the WEM from 2013. SSCPH suspects that rather than being a single factor impacting price, there are several interplays. A first point to make is that wholesale pricing in the WEM is relatively stable compared with the NEM. Low price volatility in the short-term is to be expected given the form of the capacity plus energy design compared to the very high prices experienced in energy-only markets from time to time. But price variability has also been relatively stable over the longer term (the ERA analysis covers a 5 year period), where other external impacts play a role such as fuel supply; government policy; new technologies; etc.

And while wholesale energy prices may have risen over the 5-year time-frame, the combined capacity plus energy electricity price has fallen, or at least remained stable, even in nominal terms.




*AEMO and AER data*

*Prices are nominal and unadjusted for carbon tax. WEM prices include the $/MWh weighted value of capacity, determined by capacity price x number of credits divided over quarterly consumption.*

SSCPH has performed its own high-level trend-analysis of balancing data. Attachment A1 contains some relevant charts as discussed below.

Figure A1 shows the weighted average balancing price by month from 2013, rather than as charted by the ERA as an (annualised?) energy price index. It also shows the $/MWh equivalent weighted average capacity price by month. The increase in wholesale energy price *trend* appears less clear from this data, with sharp differences month-to-month. Figure A2 adds credence to this[1].

Figures A1 and A2 show weighted average pricing. The Authority's analysis of balancing prices (Figures 10 and 11 in its Appendix 1) suggests they are becoming more volatile. The August-September period of 2016 (see Figures A1 and A2) displays a spike in average pricing. Figures A3 and A4 may go some way to explaining this. The higher morning and evening peak prices in figure A4 seem correlated to the increase in the rate-of-change of the demand profiles in figure A3. That is, the impact of solar PV appears to be creating a more pronounced ramp requirement to meet demand, which is likely increasing the price. Fast response gas generation with start-stop penalties (and minimum load requirements) face more risk when responding to

[1] The carbon-adjusted prices in Figure 1 are a crude assumption, being the WEM carbon intensity of 0.78kgCO2e/kWh multiplied by the carbon price (2018 dollar adjusted). It is unlikely that the full price of carbon would have been passed through in the WEM, given the bilateral agreements (with presumed carbon pass through) of the more emission intensive generators. Limiting the impact of carbon price could have a significant impact on the ERA's starting point of the energy price index, thus overstating the real balancing wholesale price appreciation.

demand under this scenario and are likely to price in those risks. This is exacerbated by the fact that these shoulder periods occur when significant generating capacity is on outage, meaning the mix of units able to respond is more limited than in the summer period.

Figures A5 and A6 (showing November data) show even more nuance to pricing behaviour, with the 2018 data instructive. While the ramp requirements are obviously increasing with the rapid displacement of midday load by solar PV, and peak period pricing is still relatively high, very low prices experienced in the middle of the day (often negative) are having an impact on the weighted averages, pushing the weighted average 2018 November price down (Figure A2).

A conclusion that might be drawn from the analysis is that the WEM's generation mix is ill-equipped to manage the changes in demand profile it is experiencing. Retaining the excess of aging base load generation is becoming less viable. And aging (and new) industrial gas turbines that are either too big (or their minimum load requirements are too high); or incur high penalties for short-duration runs, are not suited for the type of flexible operation that is becoming more important to the grid. As a consequence, wholesale costs, or at least a portion of costs (peak periods), are likely to continue to rise. What will be interesting will be whether these rises will be offset on aggregate by lower wholesale prices delivered in off-peak periods by new renewables and competing baseload units.

*Question 1 – What other factors may be driving up wholesale electricity prices if not demand or fuel prices?*

Generally, WEM pricing is sensitive to the availability of certain generators. Extended outages to some plant in periods of higher demand can lead to higher average pricing in that period. There have been unforeseen and extended outages to a number of efficient base load and mid merit plant over the five year period studied.

It appears that the changing load shape is also having some impact on pricing, though the impact on average prices is still unclear. Prices are becoming lower in the middle of the day (and overnight) as more must-run renewables are added and behind-the-meter solar reduces demand. However the increase ramp rates caused by these factors appear to increase peak prices. Whether average prices increase or decrease over time, it is clear that price volatility is increasing, especially in winter and shoulder periods.

*Question 2 – Do market participants consider generators are changing their bids into the balancing market to recover higher start-up and shut down costs over shorter run times?*

SSCPH has no evidence that this is the case, however the spike in prices (as per figure A4) due to the change in demand profile (figure A5) suggests this is occurring, as would be the rational response by generators that must recover the cost of generator inflexibility.

*Question 3 – Is the market applying sufficient pricing discipline on generators in light of the high level of concentration in the WEM?*

Whether prices are being set at efficient levels is unknown (given the opaqueness of the market), but the Authority's Figure 5 in Appendix 1 would suggest that there is not enough competition, or pricing discipline, in the market, particularly when setting prices above $40/MWh.

*Question 4 – Aside from disaggregation, what other measures could improve competitive discipline in the WEM? How would these measures work?*

While disaggregation leading to true competition is the preferred route to creating competitive pricing discipline in the WEM, the politics surrounding such an outcome makes it unlikely.

The most successful previous attempt to bring wholesale price competition into the WEM was the displacement tender obligation. Given Synergy has around 1,300MW of aging thermal plant (Muja C and Pinjar will be nearing the end of their useful life over the next 5 years or so); the government could ensure these are not replaced by Synergy, but via a form of 'replacement tender' obligation, either on Synergy or via a government underwritten contract-for-differences. The contract-for-differences is likely the preferred option as it would not place any new capacity under the (contracted) control of Synergy.

*Question 5 – What other factors should the ERA consider that may underlie wholesale price increases in the WEM?*

No Further Comment

**Future risks and the investment environment**

The Authority examines a wide range of issues that potentially impact the future investment environment. This is timely. The Authority does not link issues of new investment to its previous section on pricing trends… but these are intrinsically linked. The WEM suffers from a relatively poor generation mix. An oversupply of baseload generation coupled to a fleet of old inflexible gas generation. This capacity mix might have sufficed around the time of market start (and in the years prior), but the changing dynamics of the WEM, as outlined in the discussion paper, renders the current mix unsuitable. And the ownership structure of new (and replacement) generation investment will have a large impact on future wholesale price competition.

The majority of the excess baseload generation and inflexible and inefficient industrial gas turbines are reaching the end of their useful lives. In the case of older coal generation, further investment could be made to prolong the life of these units. But the changing demand dynamic means that any new investment would be very risky, with coal likely to continue to be displaced by low-cost renewables[2].

At the present, the majority of new generation investment in the WEM is occurring either behind-the-meter, with consumers bearing the cost of investment directly, or in the form of new renewable generation. New renewable generation has no doubt been assisted by federal renewable polices, which appear to be ending in 2020[3].

The WEM remains a primarily bilaterally traded energy market. There is no deep and liquid merchant energy market. New generation that cannot rely on capacity payments alone to meet returns on investment requires bilateral offtake arrangements, typically up to 10 years. The WEM remains highly concentrated. Synergy has historically been the main bilateral offtake counterparty used to underpin new development. This was especially so around the time of market start and during the Vesting Displacement process. One of the main questions going forward will be whether Synergy replaces its aging coal and gas plant with new generation… or whether the government uses the opportunity to diversify generation ownership and lower Synergy's market share by implementing new procurement obligations similar to that of the displacement process.

[2] In the NEM, low-cost renewables mostly displace the higher-priced gas generation. But the NEM has a very large base-demand which permits coal to run in baseload. In the WEM, the overnight (and now midday) demand dips below the threshold that enables all coal and co-gen plants to stay on. This means coal units are forced to cycle on and off, which is an inefficient mode of operation. It is likely that instead of spending significant sums in extending the life of its units, Synergy will save on upgrade costs and retire some units, which will also benefit by allowing its remaining coal units to operate in a more conventional manner.

[3] Both major parties have suggested they will not seek to expand or extend the existing RET legislation. However the Labor party, should it form the next federal government, has indicated it will introduce new policies to promote further renewable generation uptake.

*Question 6 – Are market participants satisfied that innovation trials are sufficiently open to participation from entities independent of government?*

No. While there is scope for some third parties to provide services to such trials, the trials themselves are typically managed by government-owned entities. A significant barrier for non-government entities participating in trials is that existing legislation and historic structures specifically preclude third parties from accessing customers, such as the laws around retailing to Synergy's franchise customers; or accessing the regulatory 'opportunity cost' of Western Power's obligation to service network customers. To circumvent these barriers, exemptions should be considered, whereby the underpinning legislations do not need to be altered in the first (trial stage) instance. Thought could also be given to implementing more competitive frameworks to run innovation trials, where other service delivery proponents are able to tender to offer services at a lower price than the state-owned entities.

*Question 7 – To what extent do market participants rely on, or derive benefit from, the electricity statements of opportunity in planning and investment decisions?*

The statement of opportunities offers a good overview of market trends and information, however it would not typically be relied on for making investment decisions.

*Question 8 – Should market participants signal intended or probable plant retirements at least three years in advance, as has been suggested in the National Electricity Market; or, should the market operator undertake its own analysis of the probable plant exit dates?*

There should be an obligation to send retirement signals to the market. The Reserve Capacity Mechanism requires Market Generators to apply for reserve capacity several years in advance. If a generator is to retire, then it follows that its failure to apply for certification in a particular capacity cycle will send the appropriate market signal. Market generators should not be able to have capacity certified for a future year, only to cancel those capacity credits due to retirement.

*Question 9 – If not advanced notice of plant retirements, what other mechanisms could be used to signal investment opportunities and improve the operation of the capacity mechanism?*

Given the existing concentrated market structure and the likely plant retirements to occur over the next 5 years of so, a dedicated 'replacement tender' process could be used to manage the orderly exit older generation and, more importantly, an orderly entry of new generation that is suitable to the ongoing requirements of the market. This could be done in a manner which also lessens market concentration and leads to greater wholesale price competition.

*Question 10 – To what extent do policy uncertainty and behind-the-meter changes in generation and storage influence decisions to develop projects in the WEM?*

Policy uncertainty surrounding large-scale renewable energy is likely to impact new investments in this area. A brief period of bipartisan policy agreement on the RET target, after years of underinvestment due to uncertainty, has seen a raft of new investments in Australia and in the WEM. This will be short-lived however, as neither major party seems intent on extending the RET. The policy positions of the next federal government and their ability to enact laws, as well as any renewable policy developed by the state government, will have a large impact on the types of investments in the WEM over the next decade. It is certain that significant existing capacity will need to retire before 2030 (and likely much sooner). What it is replaced by; and the impact the replacement generation has on the grid, could vary significantly depending on what new policy positions are favoured.

The uncertainty of technological change creates significant barriers to new investment. Certainty of revenue is a fundamental principle of efficient financing of new asset investments. The WEM does not have a deep liquid traded market for energy. And the RCM is unlikely to cover the cost of the types of flexible energy producing facilities that will be required going forward. Well-constructed bilateral offtake agreements will likely be required to underwrite investment in new flexible generation.

*Question 11 – Do market participants consider the investment environment in the WEM is challenging? If so, why?*

Revenue certainty in the WEM has traditionally been underpinned by long-term bilateral contracts. This is changing. The remaining revenue streams are relatively uncertain or bespoke (i.e. RCM set to recover capital cost of a diesel peaking generator; RET subsidises renewable energy only), and are likely to become more uncertain. Investors that cannot enter into sufficient bilateral offtake agreements will need to be vertically integrated with enough of their own demand to enable new generation investment. However, the WEM is a small market; and what demand is available is concentrated in the state-owned utility.

*Question 12 – Do market participants consider the investment environment in the WEM will improve or worsen over the short to medium term? If so, what factors will drive this change?*

The investment environment will be likely to worsen over the short-to-medium term. Some factors impacting this are:

- The market has been in a state of 'reform' for an extended period of time and this is set to continue for the foreseeable future. This naturally creates uncertainty.
- There is no clear understanding whether Synergy will replace its aging fleet. Synergy retains the best locations for new generation development; holds significant transmission and connection capacity; has a dominant market share to underpin new generation; has long-term fuel contracts and has access to the balance sheet of the state government.
- Future renewable policy is very uncertain at the moment. Any new renewable policy (state or federal) will require time to be implemented.
- The take-up rate of distributed technologies is unknown and has been poorly forecast to date. These technologies have a large impact on demand, which has decreased in the WEM over the last 2 calendar years.

*Question 13 – What is the likelihood that the State Government will need to invest to replace generation assets?*

At this point, given the uncertainties outlined in the market, this appears to be high. The real question should be: What form does the state use to underwrite new investment? Should it allow Synergy to replace retiring assets and retain its market dominance, or should it introduce new replacement procurement processes in order to diversify private investment.

*Question 14 – What could organisations such as the ERA, AEMO, Western Power and the State Government reasonably do to improve the investment environment?*

As indicated earlier, revenue certainty is an important factor in enabling investment decisions (and the financing that underpins those). In a small concentrated market, sometimes a party is required to 'make-the-market'. Synergy has underpinned most large investments to date with long-term bilateral contracts. It is possible for the state government to step into this role going forward.

Other methods of creating revenue certainty are in the construction of non-wholesale energy revenue products, such as contracts for; and types of, ancillary services. If these products and contracts are well constructed, investors will be more able to rely on this revenue going forward. This is the same notion as the capacity mechanism enabling the financing of peak generation capacity.

It appears that the WEM will migrate to a constrained access regime. However, while new renewable generation may be able to commercially connect under such a regime (which is the most likely new generation type to be constructed in areas where the grid is constrained), there will be limits to the energy transfer capability of this new generation, especially given the coincident nature of the solar and wind resource with other competing generation (both existing and proposed)[4]. Constrained access or not, there is likely to be a requirement to build out the transmission grid north of Perth to enable wind farms (and solar facilities) to transmit the quantity of energy that will be required to displace coal over the coming decades. The process for building transmission capacity is long. Western Power does not seem to have begun that process to date and pre-planning works to this end may be sensible.

**Market administration, governance and reform**

The Authority acknowledges the relatively high cost of operating, administering and regulating the WEM. Whilst small markets do lack scale to spread the costs over, there is little doubt that the WEM's market fees are too high. At what point is the question asked: Is the current market design – and evolution of that design, the most appropriate one for the WEM? Not only are the WEM costs high, but they are increasing. The most recent information regarding AEMO's expected revenue requirements for the next (AR5) period are alarming and will again substantially increase the costs of operating the market. These costs are generally attributed to introducing further complexity to the market design. Is this sensible?

Most of the added complexity being introduced into the WEM is in order to create more competitive outcomes. However the WEM is a very concentrated market[5]. Much of the benefit of the complex competitive structures will not be realised until there is some form of disaggregation of Synergy. However this does not appear to be likely in the short or medium-term future. In other words, adding further cost and complexity at this stage is unlikely to yield the market efficiencies that they otherwise might in a more competitive market.

Additionally, the WEM is not currently growing. WEM growth was reasonably robust until 2012-13, when it consumed approximately 18TWh per year, with a peak demand of just under 4,000MW. This was around the time that the market review process began (which has been persisting to now). The statement of opportunities at that time forecast that peak demand in 2022 (when current reform processes are scheduled to be implemented; and the last year of AEMO's AR5) would be 5,000MW (expected case; 5,500MW high case) and annual consumption would be 21TWh (expected case; 26TWh high case). This is not so. While AEMO still forecasts very slight growth in its most recent statement of opportunities (both consumption and peak demand), Western Power, in its most recent AA4 submissions, expects that both consumption and peak demand will decline out to 2022. Figure A7, plotting annual consumption since 2013, shows that it appears to have peaked in 2016 and has fallen in the two years since then. Figure A8, plotting January consumption (incorporating 2019 data), supports the trend[6]. This is almost certainly due to the impact of distributed solar PV which is reducing daytime demand. As solar PV continues to be installed apace, reduction in demand will likely outstrip load growth. The large-scale adoption of batteries will exacerbate this, as more generation produced behind the meter is also consumed behind the meter. *This means that the increasing cost of operating, administering and regulating the WEM need to be recovered from a decreasing supply base.* The fundamentals of funding market operations are changing and must be addressed. Failure to do so is a failure of governance.

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[4] In other words, when the wind blows (and the sun shines), all co-located wind farms (or solar plants) will compete to export energy at the same time.

[5] As evidenced by the Authority's analysis of the Herfindahl Hirschman Index, as well as the price-setting data (Figures 8 and 9 of Appendix 1 of the discussion paper).

[6] Albeit against lower than average temperatures (Perth's January mean maximum temperature is 31.2$^{o}$C)

The Authority makes the assumption that [inefficient] market costs are ultimately borne by consumers through elevated electricity prices[7]. While theoretically correct and applied in practice in most markets, there are structural idiosyncrasies which can prohibit this from occurring within the WEM. To illustrate, compare the WEM to the NEM, which is very efficient at pushing upstream costs downstream to consumers.

In both the WEM and the NEM, fees are allocated to generators and retailers (with some portion allocated to MNSP's in the NEM), although under differing proportions. Whether fees are levied upstream or downstream, customers must ultimately fund the efficient operation of the market as a component of their cost of supply. This means that those costs must make their way through the value chain to consumers.

The NEM operates a gross pool clearing mechanism. Generators are able to bid according to their real-time costs. The WEM is predominantly bilaterally traded with only a small portion of generation being cleared in the spot markets. The bilateral contracts that sit behind NEM trading are typically of short duration (1 to 4 years), meaning any contractual discrepancies, where costs are not efficiently passed through to retailers, are short-lived. Bilateral contracts in the WEM are typically much longer. And the NEM is characterised by relatively many suppliers and many retailers, meaning that competition for bilateral contracts is robust. When long-term bilateral contracts were entered into in the WEM, they were often with a dominant counterparty that was able to dictate the terms of risk allocation.

What this means is that in many instances, market fees – or the cost of operating, administering and regulating the WEM (whether efficiently or not), are caught at the project level and not passed through to consumers, as should theoretically occur. Wholesale suppliers (equity providers to generation projects) therefore bear the risk of inefficiencies of market operations and of any unforeseen increase in scope of the market fees payable.

The Authority discusses the application of cost-benefit studies to proposed reforms. Rather than focussing on the process and transparency of such studies, thought should be given to the dynamics of the actual costs and benefits. In various market reform documentation, the PUO makes it clear that end users should be the ultimate beneficiaries of the reforms, whereby the costs imposed by the reform are offset by the benefits they will ultimately receive, making them net beneficiaries. But as pointed out above, often, the costs incurred do not get passed through; hence equity investors are subsidising end users. Additionally, many of the beneficiaries of reform are prospective investors in new generation[8]. Existing participants pay for reform that allows for potential new investors to free-ride to connect, and compete directly with incumbent generators. Not only is this an inefficient wealth transfer, but is contrary to the 'causer-pays' principle. In other words, at an aggregate level the cost-benefit analysis may stack up. But in the detail there are definite winners and losers. This creates a very real regulatory/sovereign risk profile.

The Authority also notes that the AEMO's function under the Market Rules, and their ability to collect fees to administer that function, was altered in 2018 to also recover the costs of some market reform. Typically, bodies that undertake analysis to further policy objectives or implement reforms are funded by the governments of the jurisdiction they service. This is true of the AEMC, ESB (as part of COAG), AER, ACCC and PC, all of which provide input into the workings of the national electricity sector. AEMO, as the market operator, is funded by market participants. Individual states fund their own energy policy development. The market reform being managed by the PUO on behalf of the WA government has deviated from this model in several areas, some of which appear arbitrary, including that for the constrained access reforms.

While it makes good sense for AEMO to be closely involved in this reform, given their access to relevant expertise and being ultimately responsible for much of the reform's delivery, it does not follow that market

[7] Discussion Paper, page 57.
[8] Such as new wind farm proponents benefiting from the proposed shift to constrained access.

participants should fund this considerable body of work. Western Power has an obligation under its own access arrangements to enable customers to connect to its network. Implementing constrained access, to this end, should be a cost to Western Power in exercising its core function. At the least, implementing constrained access is a deferral of the capex that would need to be spent by Western Power to meet its access arrangement obligations.

The allocation of the additional costs of reform to market participants was implemented via legislative instrument. There was no consultation with industry, which is pertinent – given it is market participant's money being allocated by the Minister to AEMO. And given the previously noted issue around costs often not being passed through to consumers, this allocation of the cost via market fees is effectively forcing equity participants in the WEM to fund the government's reform agenda, to the tune of many millions of dollars. Whilst governments should fund this kind of policy development and implementation in the first instance, if it is considered appropriate for industry to contribute, it would have been preferable to first consult with market participants before appropriating their funds. Alternative funding arrangements do not appear to have been considered, such as perhaps a retail levy on franchise customers, or on the network (similar to the TAC), or other options. At the very least, if the market fees paid by participants are to be significantly altered, a broader review of how and to whom market fees are allocated might have been performed in parallel. This would ensure appropriate incentives are placed on participants and ultimately, an efficient pass through of costs to consumers[9].

*Question 15 – Do market participants consider that market operation, administration and development expenditure is delivering the benefits anticipated? If not, is the market and its electricity consumers failing to secure the benefits because of structure, governance, lack of competition, or scale?*

No. There is a clear trend of increasing market costs producing a lower level of service than that which was experienced prior to the amalgamation of the IMO and Systems Management and it transition to AEMO. Some of this lessening in value-for-money might be attributed to the cost of the transition, as well as the increased complexity of the market being operated. However it should be queried whether continuing to increase complexity in a market that is reducing in size (peak demand and consumption[10]) and is unlikely to reform its uncompetitive structure any time soon, is in the best interests of consumers.

[9] Of course, consumers will rightly argue whether they should ultimately bear the costs of government reform – especially considering the arguments made in this paper around the lack of competition in the WEM and the inability to extract benefit of these reforms.

[10] According to Western Power AA4 forecasts.

# Attachment A1

Figure A1

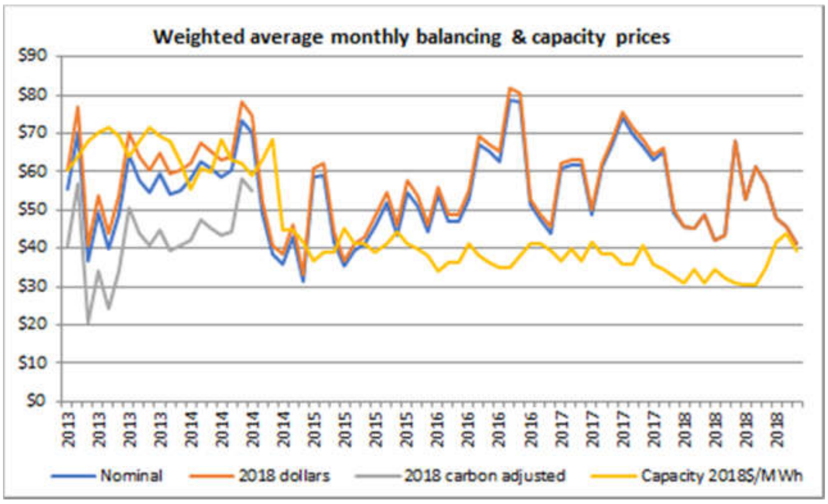


Figure A2

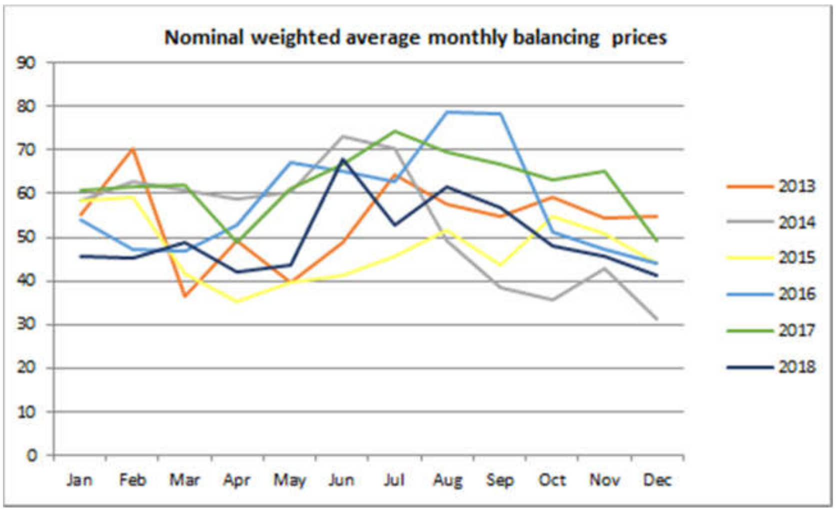


Figure A3

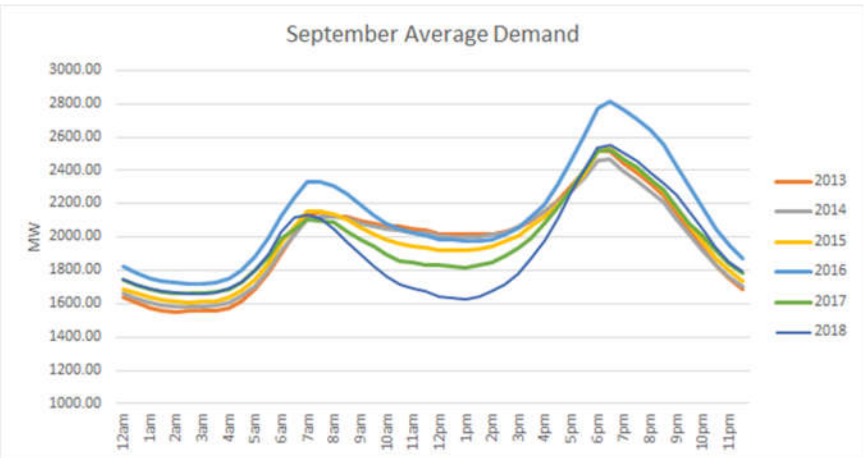

Figure A4

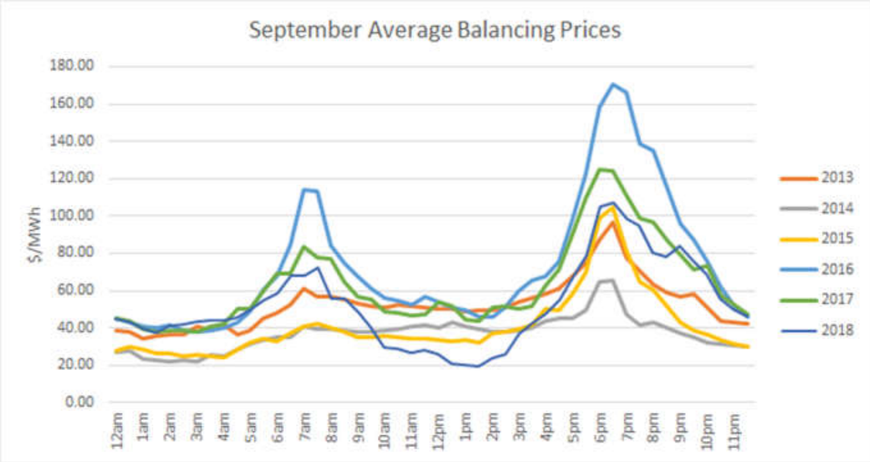


Figure A5

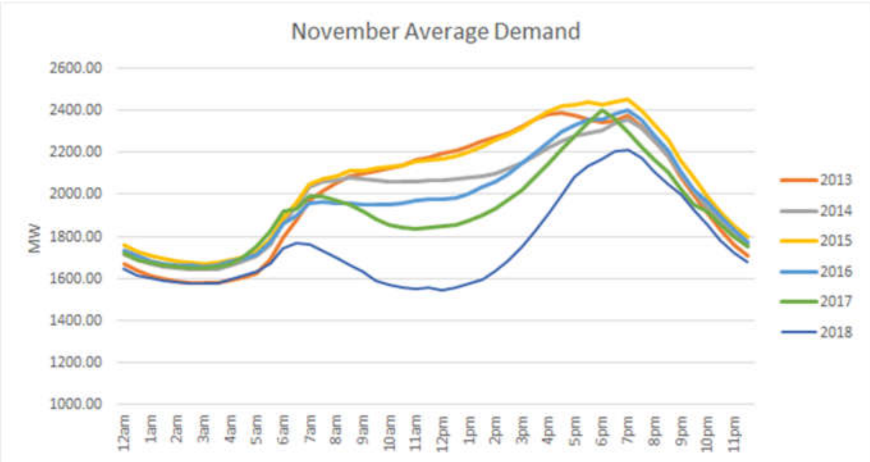


Figure A6

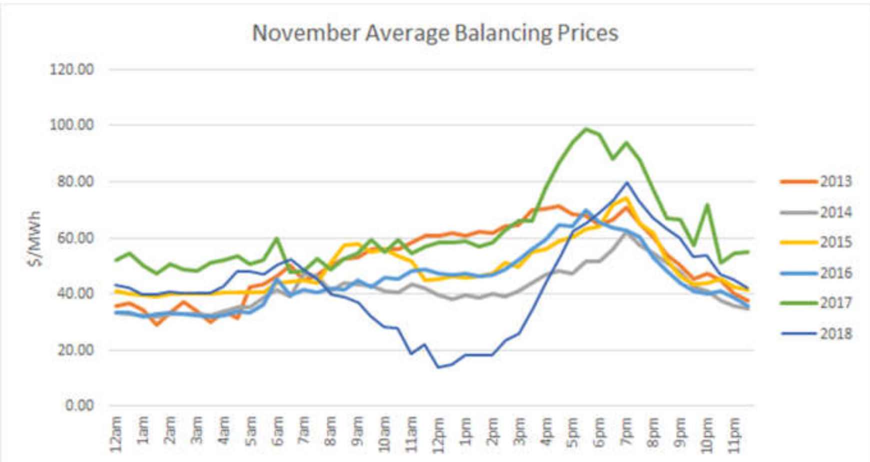

Figure A7

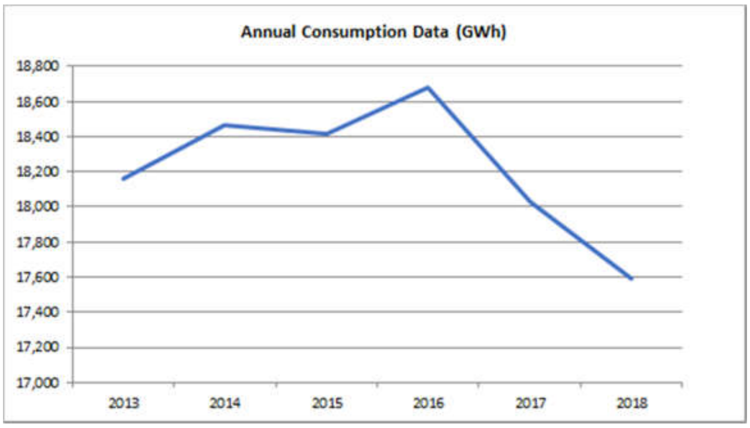


Figure A8

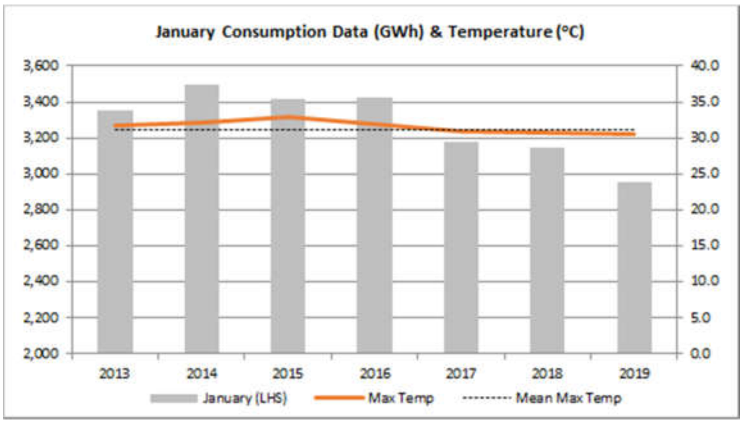


Figure A9

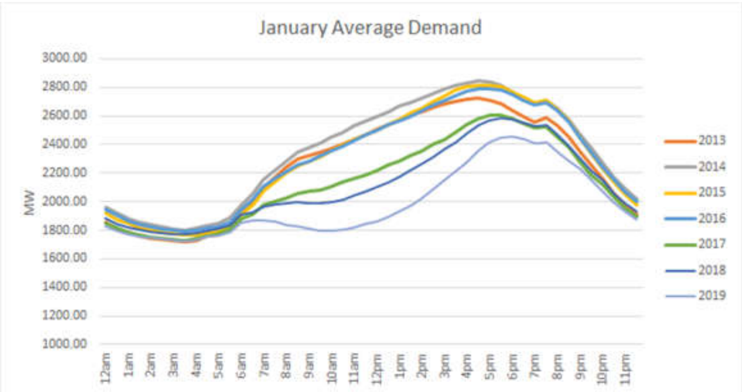


Figure A10