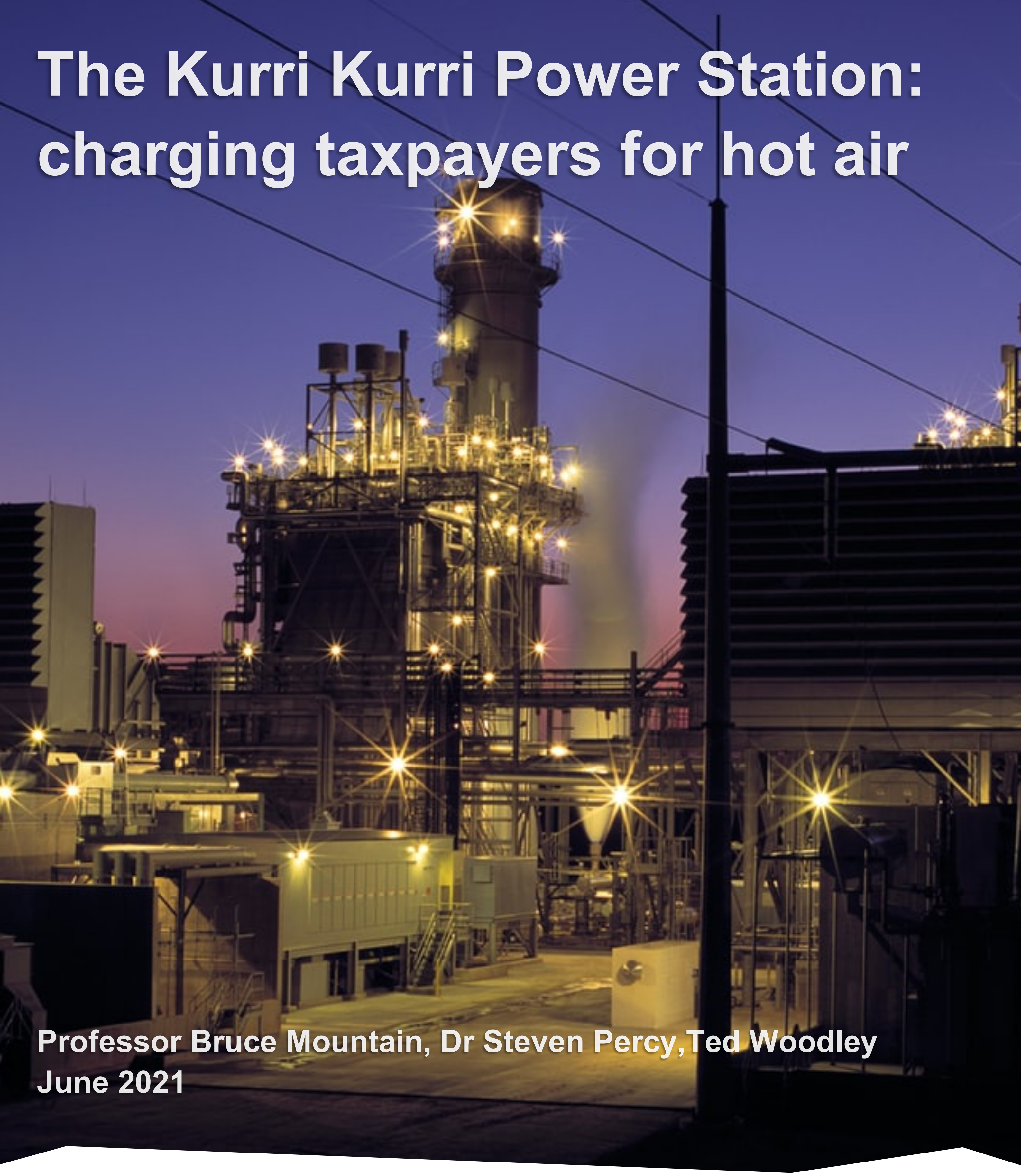
The Kurri Kurri Power Station: charging taxpayers for hot air



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EXECUTIVE SUMMARY

On 19 May 2021, the Federal Minister for Energy and Emissions Reduction announced $600 million of Government funding for a 660 MW gas/diesel power station to be built by Snowy Hydro at Kurri Kurri in the Hunter Valley of NSW[1]. The rationale for this is to *"create jobs, keep energy prices low, keep the lights on [after Liddell Power Station closes in 2023] and help reduce emissions".* This paper examines the merits of the Kurri Kurri Power Station proposal.

Until recently flexible dispatchable generation has been provided by hydro, pumped hydro and Open Cycle Gas Turbines (OCGT). All three OCGT stations in NSW (Colongra 724 MW, Uranquinty 640 MW and Hunter Valley Power Station 50 MW) were built a decade (or longer) ago. However technology development and cost reductions in lithium-ion battery chemistries have resulted in rapid growth of these batteries as an alternative source of dispatchable generation. There are now five large scale batteries in operation in the National Electricity Market (NEM) (260 MW peak production and 334 MWh storage), seven under construction (630 MW/979 MWh) and 18 between imminent financial close and commitment (5,780 MW).

Whilst a focus of this paper is the relative merit of Kurri Kurri Power Station (KKPS) compared to batteries, the underlying issue is the demand for and supply of dispatchable generation in power systems that are increasingly dominated by variable renewable generation. Numerous multi-billion dollar dispatchable generation and attendant transmission projects have recently been committed or are in the course of consideration, including the 2,000 MW Snowy 2.0 pumped hydro station, the recently approved 800 MW interconnection between South Australia and NSW, HumeLink and VNI, Victoria's 350 MW "Big Battery", the proposed 1,500 MW Marinus Link between Tasmania and Victoria, the Tallawarra B 300 MW gas power station, the NSW Government's proposal to ensure that $32bn is spent on the development of storage, transmission and renewable generation over the period to 2030, and many proposals from private developers for storage, mainly batteries.

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[1] Protecting families and businesses from higher energy prices, 19 May 2021

The main conclusions in this paper are:

1. The Government's claim that the Australian Energy Market Operator (AEMO) has substantiated the need for KKPS to fill a 1,000 MW supply gap when Liddell closes in 2023, is not true. AEMO forecasts no shortfall of dispatchable generation in NSW. In addition, recent battery and generation commitments since AEMO's latest study have further increased the supply surplus.
2. KKPS is inflexible and slow to respond, taking 30 minutes to reach full capacity from start-up (even slower than Snowy Hydro's existing Colongra gas generator). Its inflexibility will render it useless in most circumstances in the coming 5-minute settlement market (October 2021). For this reason also, the claim that KKPS will reduce prices is tenuous.
3. Peak Residual Demand (the Operating Demand less renewable generation) is declining sharply. If AEMO's coal closure and storage expansion assumptions are correct, there is no demand for long duration peaking gas generation in the period to 2030. Consistent with this, AEMO's Integrated System Plan (ISP) envisages that NSW's peaking gas generation will together produce electricity for just 4 hours per year in the period to 2030 (in the Central Scenario) or 13 hours per year (in the Fast Change scenario).
4. Using AEMO's build cost assumptions (and the demonstrated build cost of gas generators) KKPS is likely to cost at least 50% more than the $600 million that the Government has provided in the 2021/22 budget.
5. KKPS has been proposed as a source of long duration dispatchable capacity. But KKPS will have a limited supply of gas and its back-up diesel will be prohibitively expensive (and polluting). KKPS, like Colongra, is unlikely to be capable of running (at capacity) on gas for more than about five hours and it will then will take a day or so for its gas supply to recharge. Even adding its diesel, it will not be able to run continuously for around 40 hours.

We conclude that there is at best a tiny market for the sort of service that KKPS can offer and so it has no prospect of earning anywhere near the revenues needed to recover its outlay.

Perhaps AEMO (and we) are wrong and there will be a demand for long duration storage soon. But this does not imply a demand for gas generators such as KKPS. Even if it costs twice as much per MW to build an eight hour battery than to build KKPS (as it does today), an eight hour battery is still more likely to be viable than KKPS. This is because batteries are much cheaper to operate and are much more flexible. Long duration batteries will therefore be able to meet fleeting demand for long duration storage and also compete effectively in the (dominant) short duration storage market. By comparison, gas generators' much higher operating cost and much lower flexibility will inevitably have them on the sidelines in the short duration market, leaving only the rare long duration events in which they might hope to compete.

Private battery (and other storage) developers have strong incentives to understand customers' needs and to shape their business to meet those needs. There is no restriction on private developers from developing whatever type and duration of storage (or dispatchable generation) they consider most valuable. The sector is attracting huge amounts of research and development effort nationally and internationally. In Australia a thriving market is developing as existing and new participants develop technologies in response to the demand. There is much to be gained by nurturing this discovery process.

If policy makers seek higher reliability of supply than they perceive the market is delivering, there are many ways to design market contracts and incentives for innovative solutions that are likely to present little or no cost to tax payers or consumers. Policy makers should focus on this rather than burdening tax payers with the dead-weight of long-superseded technologies.

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1 Introduction

On 19 May 2021, on a visit to the Hunter Valley, the Australian Government's Minister for Energy and Emissions Reduction announced the Government's commitment to fund a 660 MW Open Cycle Gas Generator (OCGT) to be built by Snowy Hydro at Kurri Kurri in the Upper Hunter Valley. The stated rationale is that it will ensure reliable supply after the coal-fired Liddell Power Station closes in 2023, and that it will reduce electricity prices. This paper examines the Government's (and Snowy Hydro's) proposal to build the Kurri Kurri Power Station (KKPS).

Until fairly recently, flexible dispatchable capacity has been dominated by hydro, pumped hydro and OCGT. One OCGT (Colongra) has been developed in NSW in the last 12 years. It was sold for less than half what it cost to build, six years after it was commissioned.

Technology development and cost reductions in lithium-ion battery chemistries has recently seen the rise of such lithium-ion batteries as alternatives to OCGT and pumped hydro in the market for peaking generation. There are now five large scale lithium-ion batteries in operation, seven under construction and 18 at some point between imminent financial close and commitment.

A particular focus of this paper is the relative merit of KKPS in comparison to batteries. While our focus here is narrowly on KKPS, the underlying subject (the demand for and supply of dispatchable generation) is germane to numerous multi-billion dollar generation and transmission projects that have recently been decided or are in the course of consideration. The list includes: the Snowy 2.0 pumped hydro generator under construction; the recently approved 800 MW interconnection between South Australia and New South Wales; Victoria's "Big Battery" under construction; the proposed Marinus Link interconnector between Tasmania and Victoria; the NSW Government's proposal to ensure that $32bn is spent on the development of storage, transmission and renewable generation in New South Wales over the period to 2030; and the numerous proposals from private investors to develop storage, mainly batteries.

Relevant literature

The main research questions here relate to the need for dispatchable capacity (how much, what duration and when?) and the relative merits of different technologies. This has been a prominent research focus for the Victoria Energy Policy Centre since its inception.

- In our 2019 study '*Ensuring reliable electricity supply in Victoria to 2028: suggested policy changes*'[2] we recommended, inter alia, that Victorian Government policy support for large renewable generators should require that a proportion of production is firmed through the installation of storage, preferably located behind the meter.
- Our subsequent analysis in 2020 of the viability of Snowy 2.0, '*AEMO's Integrated System Plan: Does it leave Snowy 2.0 high and dry*?'[3] concluded that Snowy 2.0 had no chance of recovering its costs, that AEMO's Integrated System Plan (ISP) showed that Snowy 2.0 made no meaningful contribution to the NEM until 2033 and that there was no need to rush to expand dispatchable capacity/storage.
- Our study in 2020 '*An analysis of the economics and greenhouse gas impact of Marinus Link and Battery of the Nation*'[4] analysed the economics of Marinus Link compared to alternatives such as batteries or peaking gas generation. We quickly eliminated OCGT in the comparison on the basis that it was far more expensive than batteries. On the comparison of Marinus Link to batteries located in Victoria, we concluded emphatically in favour of batteries.

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[2] November 2019: Ensuring reliable electricity supply in Victoria to 2028: suggested policy changes https://243b2ed8-6648-49fe-80f0-f281c11c3917.filesusr.com/ugd/cb01c4_936c1ce9d0a04e1d94c9d332a693bc70.pdf

[3] August 2020: AEMO's Integrated System Plan: Does it leave Snowy 2.0 high and dry? https://243b2ed8-6648-49fe-80f0-f281c11c3917.filesusr.com/ugd/cb01c4_3349bfab274c44d9852c39b12535bbba.pdf

[4] October 2020: An analysis of the economics and greenhouse gas impact of Marinus Link and Battery of the Nation https://243b2ed8-6648-49fe-80f0-f281c11c3917.filesusr.com/ugd/cb01c4_91b44275f6b145fd92e4818713ab2107.pdf

- In research under way we are studying the scope for neural network methods in the prediction of wholesale prices (at 5 minute resolution) based on the relationship between demand and AEMO's projections of renewable generation, and will use this to examine the economics of storage.

We apply analytical approaches developed in the course of this research – particularly in respect of the analysis of Residual Demand – in this study.

Others have also focussed on relevant issues examined in this paper: The Clean Energy Council[5] compare the levelised cost of energy (LCOE) and levelised cost of capacity (LCOC)[6] for battery storage and peaking generation in the NEM. They conclude that both the LCOE and LCOC are lower for battery storage than peaking generation. Similarly, CSIRO determined batteries have a lower LCOE than peaking generation7. The Australian Energy Regulator8 examined the relationship between LCOE and capacity factors for various generation and storage technologies. However, they do not comment on the relative economics of gas generation and batteries.

Academic literature of similar issues in other countries that we have found useful includes:

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[5] https://assets.cleanenergycouncil.org.au/documents/resources/reports/battery-storage-the-new-clean-peaker.pdf

[6] LCOE or LCOC refers to the estimates of the revenue required to build and operate a generator over a specified cost recovery period.

[7] Paul Graham, Jenny Hayward, James Foster and Lisa Havas, CSIRO, GenCost 2019-20: preliminary results for stakeholder review https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2019/csiro-gencost2019-20_draftforreview.pdf

Note, CSIRO calculates LCOE uses an OCGT capacity factor of 20%. It is likely that this value would under estimate the LCOE of gas peaking generation.

[8] https://www.aer.gov.au/system/files/WEMPR%202020%20-%20Wholesale%20electricity%20market%20performance%20report%202020%E2%80%94LCOE%20%26%20LCOS%20modelling%20approach%2C%20limitations%20and%20results.pdf

- (Denholm *et al.*, 2020) examine the potential for battery energy storage to provide peaking capacity in the United States. The conclude that there is a 28 GW of practical potential for 4 hour storage.
- (Roy, Sinha and Shah, 2020) assess the technical feasibility of utility-scale PV plus battery energy. The conclude that a 50 MWAC PV system with 60 MW/ 240 MWh battery storage modelled in California can provide > 98% capacity factor over a 7–10 p.m. target period with lower lifetime cost of operation than a conventional combustion turbine natural gas power plant.
- (Rayit, Chowdhury and Balta-Ozkan, 2021) examine the economics of large scale battery storage in the United Kingdom. They conclude that a 1.2 GWh battery will be able to supply 285 GWh peak demand and achieve an internal rate of return of 8% when storage costs fall below 150 Euros per kWh.
- (Coester, Hofkes and Papyrakis, 2020) examine policy support for battery storage. They conclude that using batteries will reduce the total sum of government subsidies and external costs by up to 36% relative to policy scenarios that do not adopt batteries.
- (Babrowski, Jochem and Fichtner, 2016) examine the scope for co-located battery storage to reduce congestion and improve production from off-shore windfarms in north western Germany.
- (Frazier *et al.*, 2020) examine the potential for battery storage as a peaking capacity resource in the United States. They find that that there is substantial economic potential – greater than 100 GW in some cases – for storage with durations of ten hours or less.
- (Soini, Parra and Patel, 2020) show that for France and Germany a small share of wind and solar, the addition of battery storage actively increases nuclear and coal dispatch; and reduces the dispatch of gas generation. For larger variable renewable electricity volumes, storage actively reduces coal, nuclear and gas dispatch.
- (Denholm and Margolis, 2018) identified that storage is a potentially less expensive alternative to keeping gas generation idle for system security purposes, especially when batteries are installed with a high power-to-energy ratio. And installing the levels of storage power capacity (GW) required system security creates the opportunity to expand energy stored (GWh) capacity for reliability at a lower marginal cost than would otherwise be the case.

- (Schmidt *et al.*, 2019) compare the lifetime cost of nine electricity storage technologies. They expect battery costs to fall until 2040 and show that after 2025 lithium storage has the lowest LCOE of all storage for providing ancillary service applications, including arbitrage, peak replacement, power quality, black start, primary response and secondary response.
- (McConnell, Forcey and Sandiford, 2015) show that under the then current NEM wholesale price, there is little value in installing more than six hours of storage.

Capacity expansion optimisation modelling is widely used to plan future electricity supply systems. This approach is at the core of AEMO's ISP which uses Plexos.[9] VEPC's NEM-CEED model[10] has been used in our research and for the provision of advice. Optimisation modelling is a stock-in-trade for private energy consultancies, some of whose work is in the public domain (for example in the study of proposed regulated infrastructure such as the proposed Marinus Link[11]). Common capacity expansion studies are also applied internationally, such as United States [12,13] and Central Europe[14]. Such models usually look far ahead (many decades) and are unavoidably hostage to their assumptions (most of all of which might plausibly be estimated across a wide range). These models also calculate dispatch assuming perfect foresight and that generators offer

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[9] Plexos, Market Simulation Software, https://energyexemplar.com/solutions/plexos/

[10] Ensuring reliable electricity supply in Victoria to 2028: suggested policy changes https://243b2ed8-6648-49fe-80f0-f281c11c3917.filesusr.com/ugd/cb01c4_936c1ce9d0a04e1d94c9d332a693bc70.pdf

[11] Regulatory Investment Test for Transmission https://www.marinuslink.com.au/wp-content/uploads/2020/11/Marinus-Link-Supplementary-Analysis-Report-2.pdf

[12] NREL, Regional Energy Deployment System (ReEDS), https://www.nrel.gov/analysis/reeds/

[13] Eurek K, Cole W, Bielen D, Blair N, Cohen S, Frew B, et al. Regional Energy Deployment System (ReEDS) Model Documentation: Version 2016, National Renewable Energy Laboratory Technical Report 6A20-67067; 2016. [fix]

[14] Maeder, M., Weiss, O., & Boulouchos, K. (2021). Assessing the need for flexibility technologies in decarbonized power systems: A new model applied to Central Europe. Applied Energy, 282, 116050. https://doi.org/10.1016/j.apenergy.2020.116050

their production using short run marginal cost, whereas we know in practice that this is seldom the case.

Outline

There are three main sections to this paper:

- The first section provides context to the KKPS proposal. It describes the rationale for the proposed power station; runs through the economic consideration of competing sources of dispatchable capacity; describes the market for peaking gas generation in NSW and reviews large-scale battery developments in the NEM.

- The second section asks and answers the question of whether there is a market for long-duration storage, in the period to 2030. Contrary to the Government and Snowy Hydro's assertions we suggest that the data reveals that in fact there is no convincing evidence of such demand.

- The third section develops our five arguments: first that the evidence does not support the claim that KKPS is needed to ensure reliable supply; second that the claim that it will reduce prices is tenuous; third that KKPS's cost has been under-estimated; fourth that KKPS's capability has been over-estimated and fifth that KKPS is unlikely to recover its outlay.

A concluding section draws the main points together.

2 Context

2.1 The Kurri Kurri Power Station (KKPS) proposal

In its Environmental Impact Statement (EIS), Snowy Hydro says that it is proposing to build two F-Class gas turbine units in open cycle gas turbine configuration with capacity up to approximately 750 megawatts (MW) (the Government's subsequent Press Release says 660 MW capacity). KKPS is to be connected to the Ausgrid electricity distribution network at 132 kV. KKPS would primarily be fired on natural gas, supplied from the Sydney-Newcastle Pipeline, with the use of diesel fuel as a backup.

The EIS recognises that "*the cost of batteries is falling, making storage an increasingly commercially viable option*" but they then assert that "*storage alone will not be able to meet the shortfall in generation that will accompany the planned closure of the Liddell Power Station in 2023*" and later that "(the) *Australian Energy Market Operator (AEMO) has advised the Australian Government that with the closure of Liddell Power Station in 2023, there will be a gap in dispatchable capacity that will need to be filled through the addition of firming capacity. The Proposal's primary aim is to substantially contribute to meeting this need."*

It is claimed that KKPS has a particular advantage compared to batteries in respect of its ability to provide peaking generation for extended periods: " *... The objective of (KKPS) is to provide dispatchable capacity and other services into the NEM, and to meet demand when the needs of electricity consumers are highest … gas fuelled peaking generation is considered to be best suited, as it provides an increased level of energy reliability (relative to batteries) … primarily through provision of firming capacity over extended periods … "*.

2.2 The economics of competing sources of dispatchable generation

To provide some context to our later critique of the economics of KKPS, we set out here a broad discussion of the economics of competing sources of dispatchable generation. "Dispatchable generation" is generation with some form of accessible stored energy that can easily be converted into electrical energy, on-demand. The main forms of dispatchable energy come from:

- coal generators;
- "open-cycle" turbines (typically gas-fired but most can also burn diesel);
- "combined cycle turbines" (which combine turbines with heat recovery steam generators and are almost always gas-fired);
- reciprocating engines (which typically use diesel but can also use gas);
- biomass (which extract hydrocarbons derived from biomass and then typically combusted in turbines but can also be used in engines or boilers);
- hydro (which can be "run of river", dammed or circulated); and
- batteries (which extract electricity from chemically stored energy in a wide variety of chemistries).

The extent to which these technologies directly compete with each other depends on their cost structure and technical characteristics. The main points are as follows:

- Coal generators are one of the cheapest sources of dispatchable energy (if highly used), but they are inflexible in that they require a minimum level of production to be stable (typically about half their capacity). Only a small amount of their production can be varied quickly; they take a long time to start-up (many hours if they are cold) and shut down; and of course they have substantial environmental impacts. Generally they cannot switch on and off within 24 hours and the costs per unit of production rise quickly as production declines.
- Combined Cycle Gas Turbines (CCGT) are similar to coal generators in many respects. They are much more efficient but they cost more to run (because gas is more expensive than coal per unit of energy). CCGT is more flexible than coal (much quicker start times and higher ramp rates). They can switch on and off within 24 hours.
- Open Cycle Gas Turbines (OCGT) cost much more than CCGT or coal to run but they are more flexible (typically they can be synchronised to the power system within 5 minutes and reach full production within 30 minutes). They can switch on and off several times a day.

- Hydro can respond quickly (synchronise to the power system within minutes and ramp to full production within minutes), although larger hydro units are much slower than smaller units. In addition, Hydro is typically expensive to run where water supply and/or storage capacity is limited.
- Pumped hydro can increase load quickly (when pumping) and can ramp up production quickly (when producing) but is slow to change between pumping and generating and vice versa). Pumped hydro faces an energy cost based on the price paid when pumping plus compensation for the losses involved in pumping and generating (which will typically require the sales price to be at least 40% higher than the purchase price).
- Lithium-ion batteries (by far the dominant chemistry) are incredibly flexible (they can go from demand at full capacity to production at full capacity back to demand at full capacity within milliseconds, repeatedly). The cost of a battery per MW of peak production depends on how long it is able to sustain that production. There is some scale economy in storage capacity: relatively short duration batteries (less than 2-hours) cost about 30% less (per MW) than 4-hour batteries which in turn cost about 30% less than 8-hour batteries. Batteries have a shorter life (10-15 years) than gas turbines or hydro, and their capacity degrades (about 25% over 10 years seems to be widely assumed, although this depends on how it has been used). However battery installations are likely to have substantial residual value at the end of the life of the battery (much of the installation – inverter, control systems, infrastructure, connection will continue to be valuable – and even "end of life" batteries will continue to be useful, even if they are only able to discharge at 25% below their "at-new" rated capacity). Batteries can be expected to have "round-trip" losses of around 10%. Unlike its competitors – hydro and OCGT – the operating cost of a battery is very much lower (close to zero or even negative since it will charge when electricity is cheap or when prices reduce below zero).

To provide a sense of the relative economics of OCGT compared to a 2-hour battery,

Figure 1 shows the average electricity price an OCGT requires (in addition to the amount needed to recover its production cost) in order to recover its capital outlay over 25-years, as a function of the capacity factor (the percentage of time they are producing). As a point of reference, the EIS says that KKPS is expected to operate at a 2% average annual capacity factor. Assuming KKPS is remunerated through spot market sales, this means it requires prices above $793/MWh over a 25 year life (plus the avoidable operating costs i.e. fuel and variable operating costs – likely to be at least $120/MWh if burning gas but much more if burning diesel) if it is to recover its capital outlay.

By comparison, Figure 2 shows the average "arbitrage margin" (the difference between the buy and sell price) that batteries require in order to recover their capital outlay assuming a 10 year life and zero residual value (noting this is an implausibly conservative assumption), as a function of their capacity factor.

These two figures explain the relative economics of OCGT and batteries in terms of the price they require to recover their investment, before recovery of their operating costs, as a function of their usage (capacity factor). However it is not appropriate to compare the economics of OCGT and batteries assuming that they both operate at the same capacity factor: Batteries have much lower avoidable costs than OCGT since they are likely to charge up when the spot price of electricity is close to zero or even negative. On the other hand, the avoidable cost of OCGT is likely to be at least $120/MWh if burning gas. This means batteries will operate with much higher capacity factors than OCGT even leaving to one side the impact of their much greater flexibility (batteries can effectively compete to supply stochastic 5 minute peak prices while OCGT has no chance of starting up in time). This is reflected in AEMO's ISP modelling which assumes batteries typically operate at circa 7% capacity factors in the period from 2025 to 2030 while OCGT has an average annual capacity factor of just 0.05% in the Central Scenario or 0.12% in the Fast Change scenario (we return to this later).

Figure 1. Average spot price needed for an OCGT to recover its capital outlay over 25 years (before inclusion of avoidable production costs)

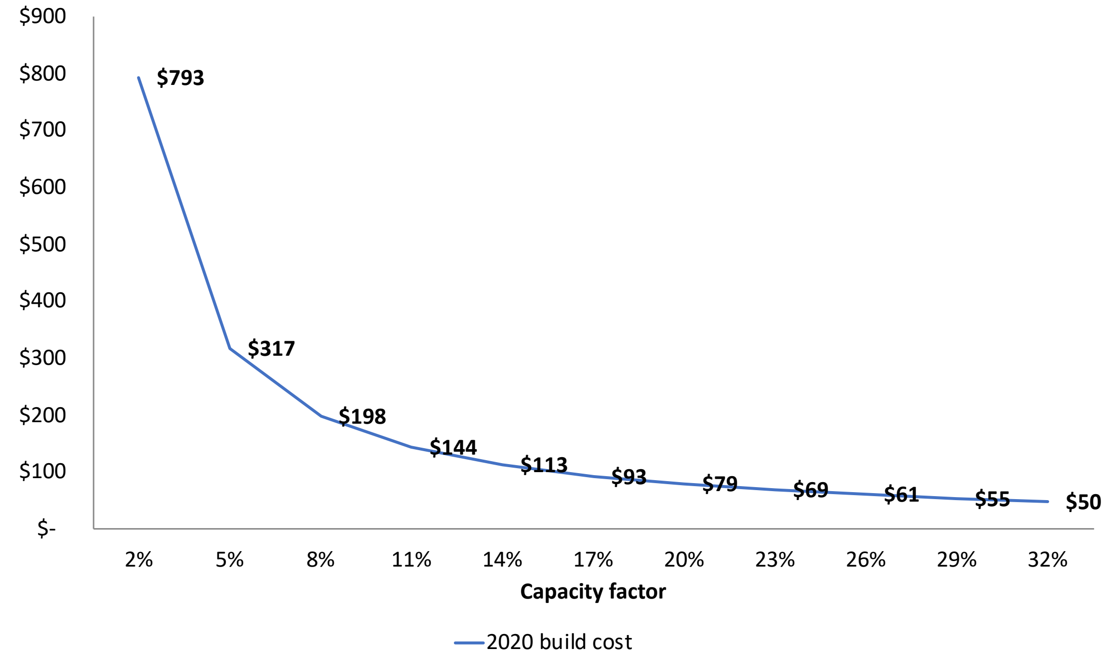
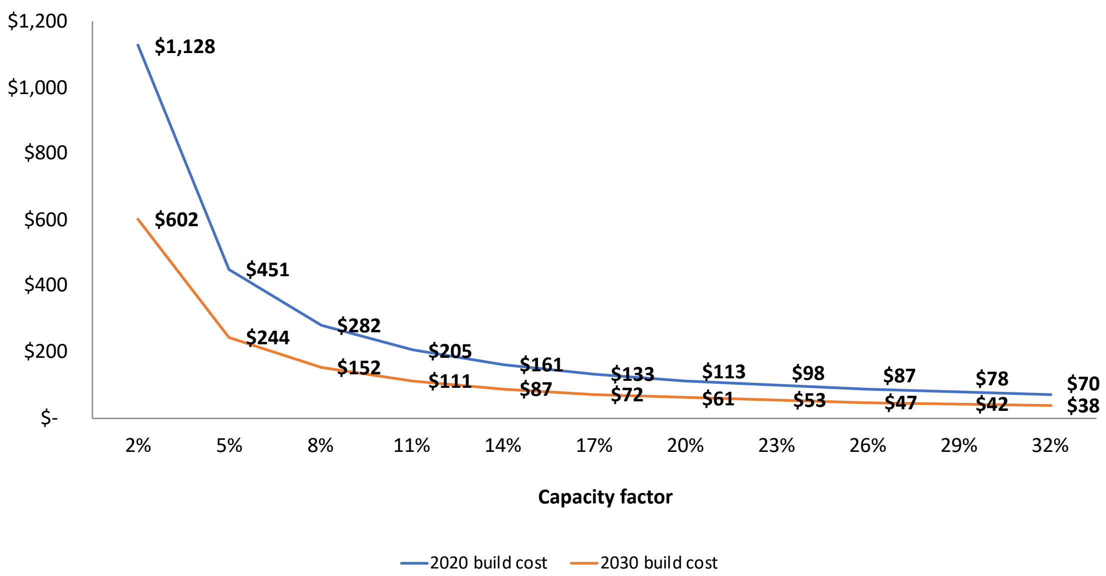


Figure 2. Average arbitrage margin needed for a two hour battery to recover its capital outlay over 10 years



2.3 The market for peaking generation in NSW

Currently dispatchable "peaking" generation in NSW comes from gas turbines (Colongra, Uranquinty and the Hunter Valley Gas Turbine) and from several hydro and two pumped hydro generators (Tumut 3 and Shoalhaven). Hydro and pumped hydro generators are much more flexible (quicker to start and ramp-up to full generation) and far cheaper to operate than gas generators (if their water supply is not constrained). Consequently, the majority of NSW peaking generation comes from hydro. However hydro is often affected by water availability (which in some cases is also affected by environmental and agricultural demands) and pumped hydro generation is affected by the cost of pumping water. The hydro/gas generation markets are sufficiently different from each other that in this sub-section we focus only on the gas turbine peaking market (but for interested readers we provide the comparable information for the hydro/pumped hydro generators in Appendix A).

OCGT production

Table 1 shows the capacity and operating information of the three NSW peaking gas (OCGT) generators over the period from, 1 January 2017 to 30 April 2021.

Table 1. NSW Peaking generation operation 1st January 2017 to 30th April 2021

	Colongra	Uranquinty	Hunter Valley
Technology	OCGT	OCGT	OCGT
Maximum Capacity (MW)	724 (non-summer rating)	664	50
Capacity factor (%)	0.4	7.7	0.3
Volume weighted average price received ($/MWh)	545	158	601
Generation (GWh)	112	1936	6
Spot market revenue ($m)	62	306	3.5
Time synchronised (%)	1.5	14.5	0.7
Average dispatch (MW)	201	352	22
Median time per start-up (hours)	1.3	3.5	1.1
Max time continuously (hours)	15	44	8
Number of starts	227	984	138

Source: VEPC analysis from data extracted from https://nemdashboard.com.au/ **originally extracted from www.aemo.com.au**

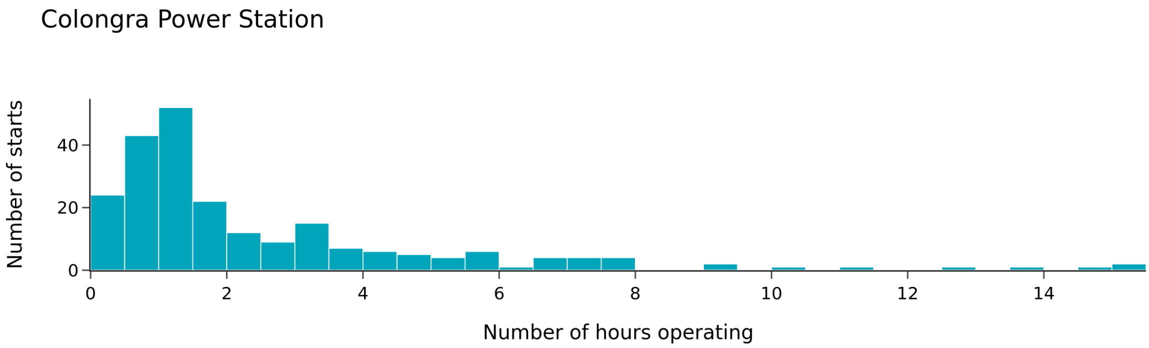
The table shows that Uranquinty (owned and operated by Origin Energy) was by far the most used of the three OCGT generators. It started up and synchronised 984 times (a bit over 4 times per week), typically (i.e. median) ran for 3.5 hours and its average production when dispatched was 352 MW (about half its capacity).

Hunter Valley Gas Turbine (owned and operated by AGL Energy) was the least used but only slightly less so than Colongra.

Colongra (owned and operated by Snowy Hydro since 2015) started up once per week on average, it was typically synchronised to the power system for just 1.3 hours when it was dispatched and its average dispatch (201 MW) was less than a third of its capacity. Its average capacity factor was just 0.4%. This is obviously far below the expectations that Delta Electricity had when it decided to build Colongra. When it was commissioned in 2009, the then NSW Energy Minister, Ian McDonald described Colongra as an environmentally responsible way to meet the state's growing electricity demand and "great news" for electricity consumers and the environment.[15] Actually both peak and average demand in NSW (measured on the transmission network) have declined significantly since then. The NSW Government sold Colongra just six years after it was commissioned for $234 million, less than half what it cost to build.

Figure 3 provides more granular information on the frequency with which Colongra has been dispatched over the period from 1 January 2017 to 30 April 2021. For more than 80 of its 227 starts, Colongra was dispatched for two hours or less. Only 8 times in the 4.4 years was Colongra continuously dispatched for nine hours or longer and always for much less than its full capacity.

Figure 3. Distribution of continuous production duration (hours) per synchronisation from Jan 2017 to April 2021



[15] http://gastoday.com.au/news/colongra_cruises_along/00738/

OCGT is most likely to operate when there is a very high Residual Demand (RD)[16] and all other sources of dispatchable production have been exhausted (because it is one of the most expensive way of meeting RD).

Figure 4 shows the five days in 2020 with the highest RD in NSW. Four were in summer and one was in winter. The summer peak demand ramps up gradually from the morning and stays near the highest value, at around 6pm, for about three hours before ramping down. Winter peak demand days have a significantly different characteristic, with two peaks instead of one. The smaller peak occurs in the morning and the larger peak in the evening. The winter evening peak lasts about half as long as the summer peak.

Figure 4. Peak Residual Demand days in 2020

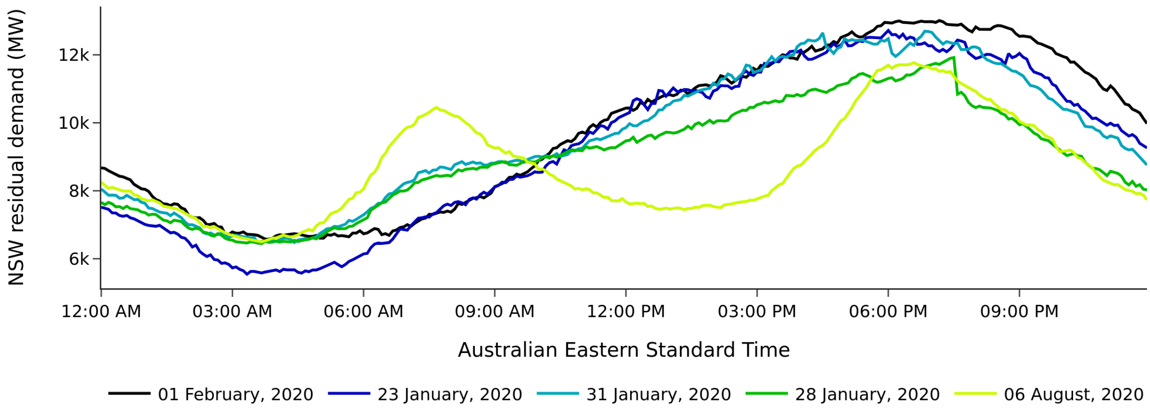


Figure 5 shows the dispatch of Colongra on the same peak Residual Demand days shown in Figure 4. It was dispatched at capacity for about three hours on the second and third highest summer RD days, hardly at all on the highest RD day and not at all on the fourth highest summer RD day and winter peak RD day. This suggests Colongra has not been a significant supplier at the times of the highest RD, though we recognise that prices at the time of these peak RD have not always been sufficiently high to cover Colongra's avoidable costs (we examine this further below).

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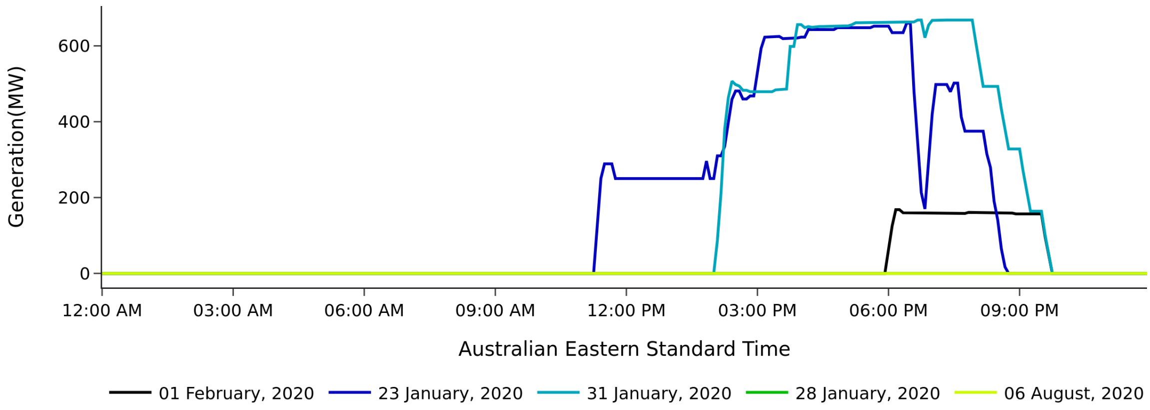
[16] Residual Demand is Operating Demand less rooftop solar less large scale renewables, and is the demand that is available to dispatchable supply.

Figure 5. Colongra Power Station generation on peak RD days



Appendix A provides the same chart for Uranquinty Power Station, which was dispatched on all summer peak RD days.

The analysis of OCGT production has so far focussed on the response of OCGT to peak RD days. It is instructive to examine how long high prices were sustained and examine the relationship between OCGT production and prices. **Error! Reference source not found.** is a histogram that shows how many times successive 5-minute Trading Interval prices above $100/MWh were sustained over the period from 1 January 2017 to 31 April 2021.

Figure 6. Frequency of continuous periods that 5-minute prices above $100/MWh were sustained, over the period 1 January 2017 to 31 April 2021

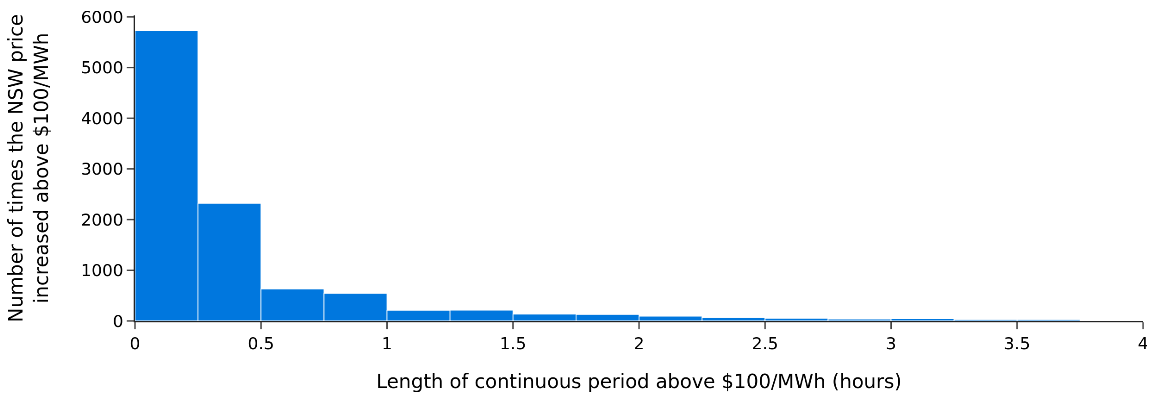


Figure 6 shows that for around half the time that 5-minute prices were above $100/MWh, they were not sustained at that level for more than 15 minutes (three successive 5-minute intervals) continuously. They were sustained between 15 and 30 minutes 2,300 times (22% of all instances), between 30 minutes and one hour for 2,070 instances (19%) and between one hour and two hours for 5% of instances, and for longer than two hours for just 4% of instances. Has OCGT, and Colongra in particular, been able to respond effectively to such short duration peak prices?

Figure 7 and Figure 8 chart the relationship between Colongra dispatch and the 30-minute Settlement Period prices it received.

Figure 7. Relationship between Colongra dispatch and 30-minute Settlement prices up to $500/MWh (from 1 January 2017 to 30 April 2021)

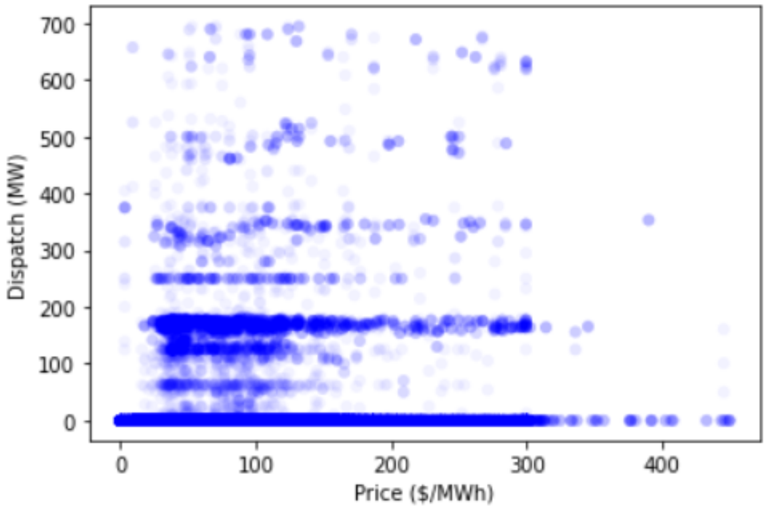
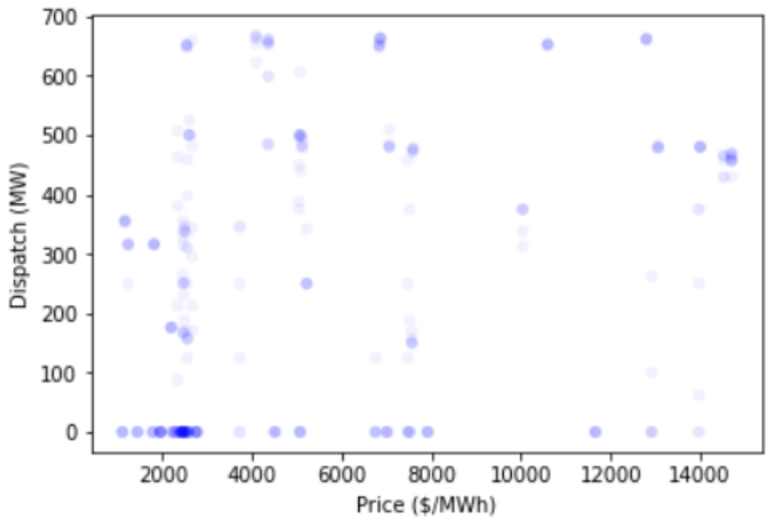


Figure 8. Relationship between Colongra dispatch and 30-minute Settlement Period prices between $500/MWh and $15,000/MWh (from 1 January 2017 to 30 April 2021)



These figures show that Colongra frequently produced when the Settlement Price was below a conservative estimate of its avoidable costs ($120/MWh). It also shows that Colongra frequently failed to produce at all or at a level far below its installed capacity when the Settlement price exceeded its avoidable costs. Perhaps market power (“strategic withholding”) might explain the failure to respond during some of the extreme price events, but a more generally plausible explanation is likely to be found in the fact that Colongra is simply not sufficiently flexible to respond effectively to the rapidly change prices. This will be even more problematic as the market moves to 5 minute settlement prices from 1 October 2021.

OCGT income

Table 1 shows that Colongra received an average price of $545/MWh when it was dispatched over the period 1 January 2017 to 31 April 2021. Over this period Colongra received income from the spot market of $62m ($13.8m per year on average), compared to $306m and $3.5m for the Uranquinty and Hunter Valley Gas Turbine. Over this period, total production was 112 GWh, 1936 GWh and 6 GWh, respectively. Assuming avoidable operating costs of $120/MWh, Colongra delivered gross margins (assuming all electricity was sold at spot) of just $10.3m per year. After maintenance and operations expenditure, Colongra is unlikely to have broken much less made any contribution to the recovery of its $234 million purchase price.

An alternative perspective on the financial viability of Colongra uses information from the sale of cap contracts (which limit the maximum price to $300/MWh in return for an insurance premium, the cap price). Appendix A presents data on the weighted average cap prices for quarterly caps in NSW from Q1 2017 to Q1 2021 and also the price history– showing that in almost all cases cap prices have declined over the course of their trading periods. The average of the four 2021 prices of NSW cap contracts is currently $8.5/MWh (and is likely to continue to decline as the year progresses). Assuming Colongra sold half its capacity in cap contracts, that would deliver an annual income of $25m which, after subtracting operating costs (assume average annual production over the last four years) delivers gross margins of $21m per year, again below the amount needed for Snowy Hydro to recover its purchase of Colongra.

It is unlikely that Snowy Hydro would contract more than half Colongra’s output, not least because the start time and ramp rate constraints of the plant limits its ability to hedge half-hour settlement prices (we noted earlier that Colongra only dispatched to capacity during 2 of the 5 highest demand days in 2020 and Figure 7 and Figure 8 show ineffective Colongra was in producing even when prices were far above avoidable costs).

This inflexibility is likely to become even more of a handicap when the market moves to a 5-minute settlement (from 1 October 2021). Colongra will need to defend its caps against 5-minute prices, not against the average of six five minute prices (as now). Inevitably Colongra (and KKPS) will be exposed to much higher risk after the introduction of 5-minute settlements for the cap contracts it sells since it has much weaker ability to defend such contracts than it does to defend 30-minute contracts. If Snowy Hydro wishes to contract a similar proportion of Colongra output it will be exposing itself to far higher trading risks considering its much weaker ability to defend 5-minute than 30-minute prices.

This analysis suggests that OCGT is unprofitable in NSW and helps to explain why investors have not developed any new OCGT for the last decade. We note that the recent decision by Energy Australia to build the 300 MW Tallawarra B OCGT was only possible after an $83 million gift from the NSW and Commonwealth Governments (accounting for approximately 25% of its outlay).[17]

2.4 Overview of battery developments

Batteries are the obvious alternative to KKPS. There are currently five grid-scale batteries in operation, three of which are stand-alone and all of which have required high levels of policy in the form of capital subsidies and/or policy-driven off-take contracts. The total peak capacity of these five batteries is 260 MW and storage is 334 MWh; meaning that these batteries can produce at their maximum rating for 1.3 hours if fully charged.

There are seven grid-scale batteries under construction with an aggregate peak capacity of 630 MW and storage of 979 MWh, meaning that peak production can be sustained for 1.6 hours if the batteries are fully charged. Only two (the Victorian Big Battery in Victoria and Wallgrove in New South Wales) are stand-alone and both are policy-driven based

[17] Tallawarra B also has many other advantages relative to KKPS including a much more secure gas supply, its location adjacent to an existing generator and its connection to the electricity grid.

on reliability and network support considerations. The remaining five (which account for around 300 of the 630 MW) are co-located and don't rely on policy support.

There are currently five grid-scale batteries with aggregate capacity of 1,500 MW that are not yet under construction but that seem likely to proceed. The storage capacity of four of the five (in total 1250 MW) has been announced (4,450 MWh), meaning that peak production can be sustained for 3.6 hours if the batteries are fully charged. Three of the five (80% of total capacity) are co-located with generation and two are stand-alone and likely to involve policy support (probably in the form of guaranteed off-take contracts).

There are currently 13 grid-scale batteries that have been publicly announced but whose progress to commitment is not yet certain. The aggregate capacity is 4,280 MW but the storage capacity of only 1,310 MW has been identified. Nine are co-located. The other four are stand-alone and one (Powercor's proposals to develop numerous grid-scale network batteries) is likely to require regulatory approval to proceed.

We draw the following observations from this information:

a) Battery development to date has relied on policy support but this is quickly reducing, particularly for batteries co-located with generators.
b) The majority of expected future battery developments will be co-located with generators. Two of the five operational batteries are stand-alone but only two of the seven batteries under construction are stand-alone.
c) Battery duration is increasing, typically from just over one hour to nearly four hours, although there seems to be some disparity between co-located and stand-alone batteries (the latter typically being of shorter duration).
d) There are many different competing developers; most are new entrants to the electricity industry.

In addition to these grid-scale batteries, consultants Sunwiz[18] claim that at the end of 2020 there were 110,000 behind-the-meter small scale batteries, whose aggregate storage

[18] https://www.sunwiz.com.au/battery-market-report-australia-2021/

capacity we estimate to be around 800 MWh (more than twice operational grid-scale batteries). Sunwiz forecasts that in 2021, there will be 33,000 home energy storage systems adding 334 MWh of storage capacity (i.e. equal to the capacity of currently operational grid-scale batteries).

3 Is there a demand for long-duration dispatchable power?

The focus of this paper so far has been on describing, broadly, the relative economics of different types of dispatchable power, on understanding the existing market in NSW for OCGT and understanding the rapidly developing battery market. In this section we look into the future to answer the question of whether there is demand for long-duration dispatchable power in NSW. As described earlier, the EIS asserts that such demand exists (and that KKPS is ideally placed to meet it).

On the basis that wind and solar production is now by far the cheapest source of electricity and on the basis that it will be dispatched when the wind and sun are available, the market for dispatchable power can be quantified by establishing the Residual Demand (RD). RD is the demand available to be met through dispatchable supply (because variable renewable supply will always out-compete dispatchable supply when the variable renewable resource – sun or wind – is available) and is established by subtracting variable renewable production from operating demand.[19]

Figure 9 shows the maximum historical and forecast RD in NSW based on the 2020 AEMO ISP forecast. This shows a forecast reduction in RD from about 13 GW in 2020 to 12.25 GW for the Central scenario or 12.16 GW for the Fast Change scenario in 2023. After 2023, maximum RD remains relatively flat. We also note there is not a significant difference between the Central and Fast Change scenarios. Peak RD is declining because

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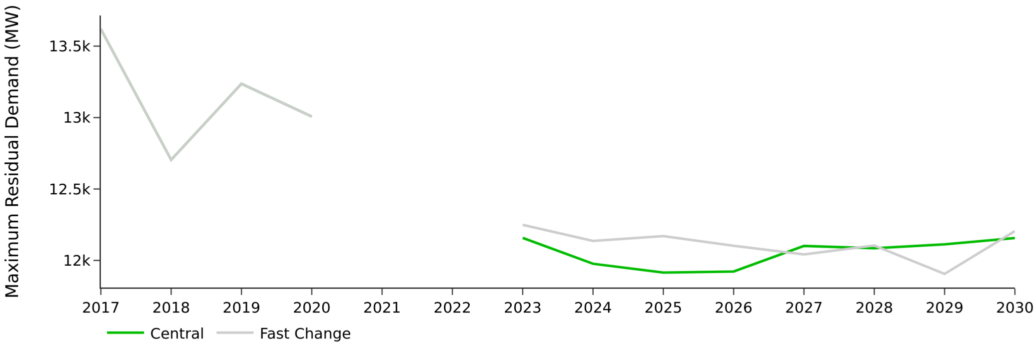
[19] The operational demand was sourced from the AMEO 2020 ISP, using a 10%POE, 2019 reference year, and for the Fast Change and Central scenarios. We produced the renewable profiles by multiplying the DP1 ISP capacity expansion for the fast change and central scenarios for each renewable energy zone (REZ) by the corresponding REZ 30-minute generation profile, then we summed the renewable production for all REZs in NSW into a single state-wide renewable profile. Data to replicate our analysis can be obtained from https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp/2019-isp-database

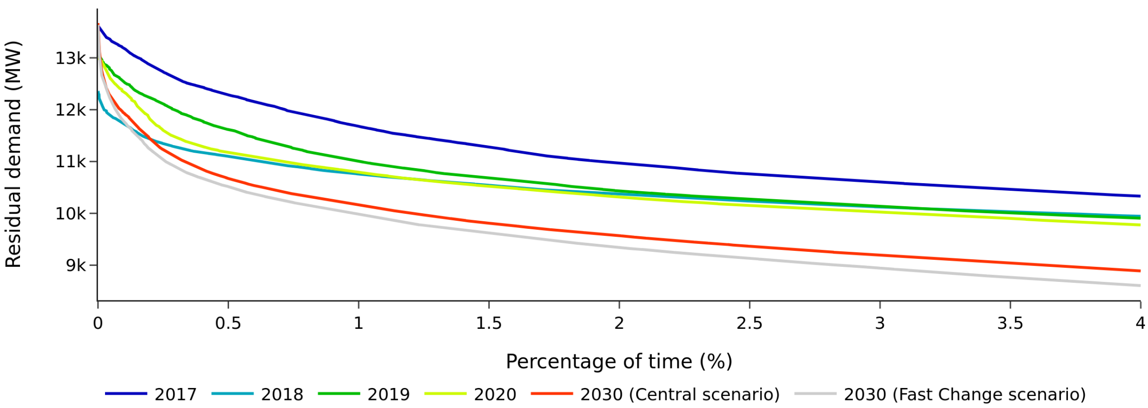
AEMO forecasts an increase in generation from wind farms[20] and behind-the-meter storage.

Figure 9. Maximum Residual Demand (actuals to 2020, projections from AEMO ISP to 2030)



In Figure 10 we have ranked the highest 4% of RD half-hours (using actuals up to 2020 and the data in AEMO's Central and Fast Change scenarios for the projections to 2030). The y-axis value corresponding to the x-axis value shows the percentage of half-hourly intervals (in a year) in which RD is at that level or higher. The chart shows the decline in RD from 2017 to 2020 and a further substantial decline in the period to 2030. For the highest 0.5% of 2030 it is around the level of the 2017 to 2020 average (but far below the 2017 actuals).

Figure 10. Residual Demand duration curve showing the top 4% of time periods



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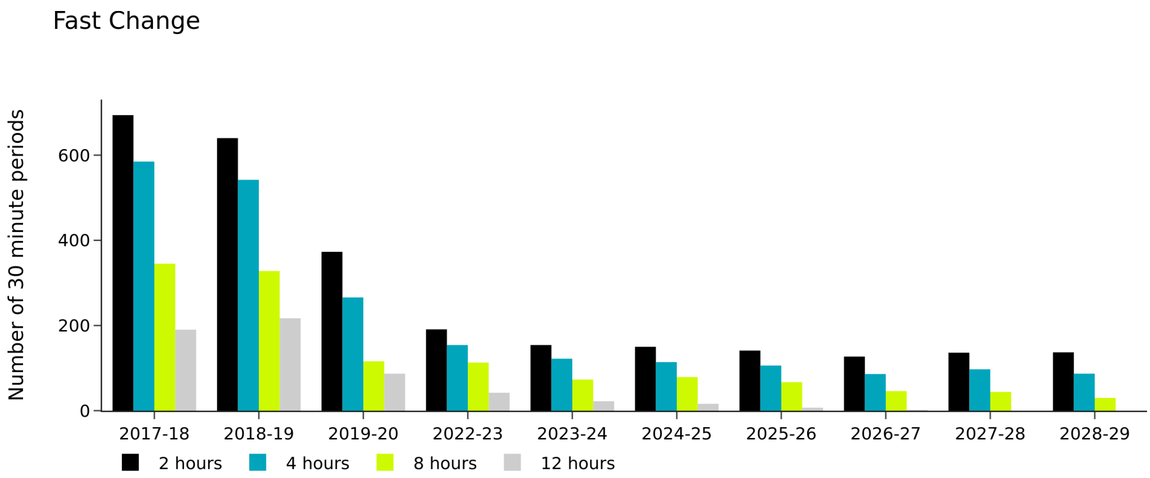
[20] Of course solar production is expanding rapidly too, but RD is getting ever smaller as solar generation expands. For the foreseeable future, the highest RD occurs at the time of the evening demand peaks and it is wind generation (and behind-the-meter storage) at these times that reduces RD.

Figure 10 ranks the RD in each half-hour independently of each other. Another way of assessing RD (and hence the value of storage of different durations) is to understand how long high levels of RD are sustained. We establish this by measuring the rolling average value of RD using 2/4/8 and 12-hour measures. For example, the 12-hour rolling average measures the average value of RD over the previous 24 half-hours. We have then calculated the number of times that these 2/4/8 and 12-hour moving average RDs are higher than 10 GW using the actual values from 2017 to 2020 and the forecast values to 30 June 2029 that we have extracted from the half-hourly data traces of Operational Demand and variable renewable generation in AEMO's ISP. The results of this analysis are shown in Figure 11.

Figure 11. Frequency distribution of 2/4/8/12 hour moving average Residual Demands that are greater than 10 GW



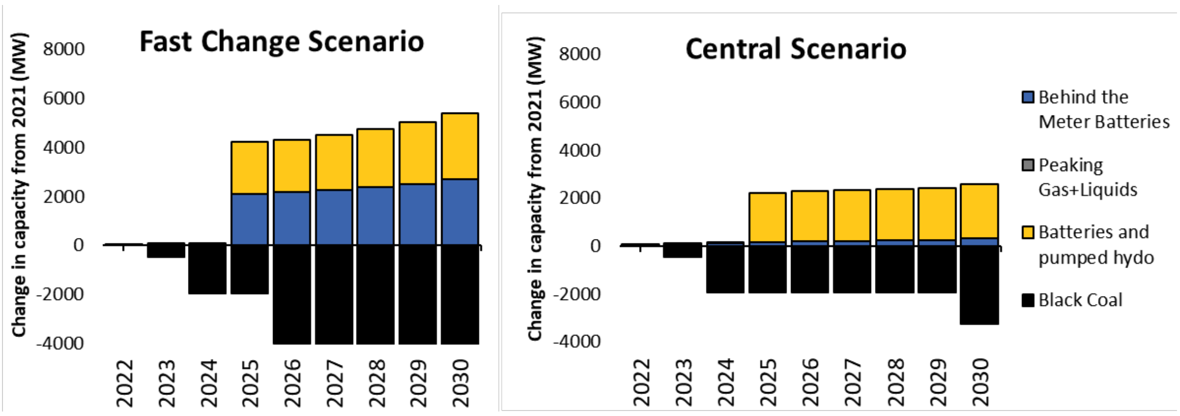
Source: VEPC AEMO 2020 ISP data traces

This shows, for example, that the 2-hour rolling average of RD exceeded 10 GW for about 700 half-hours in 2017/18. It had roughly halved (to below 400 half hours) in 2020 and using AEMO's projections will only occur in about 100 half hours in 2028/29. At the other end of the duration spectrum, there were about 190 half hours in 2017/18 when the 12 hour rolling average RD exceeded 10 GW. By 2026/27, AEMO's projection in the Fast Change scenario is that are no half hours in which the 12 hour rolling average RD is greater than 10 GW (in fact from 2023 it is inconsequentially small).

This analysis leads to the conclusion that before accounting for the effect of coal generation closure, the market for long-duration storage has contracted quickly over the last three years and using AEMO's projections it will continue to contract until the end of our assessment period (30 June 2029). This decline can be explained by the reduction in Operational Demand attributable to the expansion in behind-the-meter storage and also the increase in variable renewable generation, particularly wind farms which reduce Residual Demand peaks (which occur in the late afternoon and evenings when solar generation has declined).

The analysis to this point focuses on the changes to the underlying demand for RD after accounting for the expansion of variable renewable generation and Operating Demand. It shows that this underlying demand is declining. But there will also be a demand for dispatchable generation / storage to replace the dispatchable generation provided by closing coal generators. Figure 13 shows the coal generation capacity reductions in AEMO's Central and Fast Change scenarios and the change in dispatchable capacity. In the Central Scenario, coal generation capacity reduction is offset by matching increases in the capacity of batteries and pumped hydro. In the Fast Change scenario, more rapid coal generation closure from 2026 is matched by large increases in behind-the-meter battery storage. Neither scenario shows any increase in gas generation.

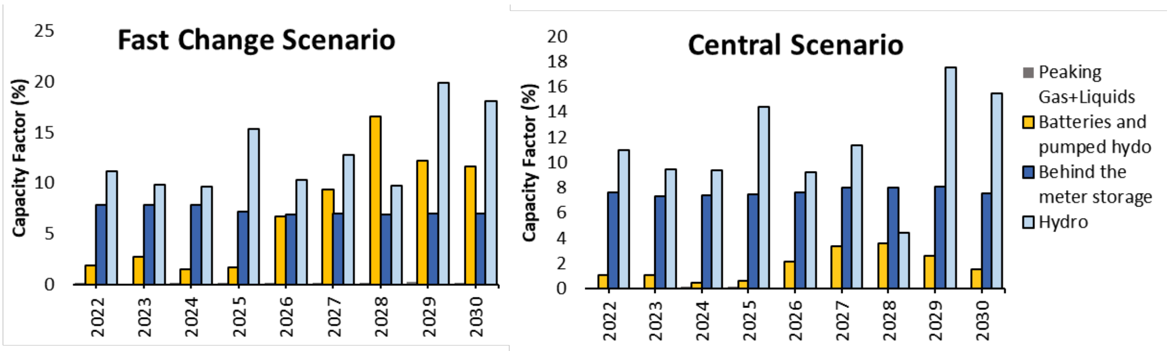
Figure 12. Change in peaking capacity in NSW for fast change and central scenarios.



Source: 2020 AEMO ISP, Generation Outlook

Figure 13 shows the capacity factor of flexible generation. In NSW, hydro operates at similar rates for the Fast Change and Central scenarios (as there is a fixed amount of water); batteries and pumped hydro are much more heavily used in the Fast Change scenario; peaking gas (and liquids) has an average capacity of just 0.12% in the Fast Change scenario and 0.05% in the Central scenario.

Figure 13. Calculated NSW peaking capacity factor using AEMO 2020 ISP capacity and generation values for fast change and central scenarios.



Source: 2020 AEMO Integrated System plan, Generation Outlook

Bringing these strands of analysis together, we conclude first that underlying peak Residual Demand is declining sharply; and secondly that if AEMO's storage expansion assumptions are correct, there is no demand for long duration peaking gas generation in the period to 2030.

4 Critique

4.1 The need for KKPS is not substantiated

As we described earlier, no attempt has been made to justify KKPS on the basis of an economic (do benefits exceed costs?) or financial (is it profitable?) assessment. Instead, the EIS asserts that KKPS is needed on the basis of reliability i.e. to meet supply shortfalls that it asserts exist, referring to the 2017 Electricity Statement of Opportunities (ESOO) published by AEMO.

However the most recent update to the ESOO, published in May 2021, suggests that there is no generation capacity shortfall in the NEM Reliability Standard (a maximum expectation of 0.002% of energy demand to be unmet) in the period to 2030. Against the even more stringent "Interim Reliability Standard" (unserved energy is not expected to exceed 0.0006% of demand) the latest ESOO concludes that by 2028/29, 840 MW more capacity is needed to meet the standard. However this does not include 300 MW for Tallawarra B OCGT (which at the time did not meet AEMO's "committed" criteria) or the Edify/Shell 100 MW battery that has since been committed. The Energy Connect Interconnector has also now received regulatory approval and it will add around 800 MW transfer capacity between South Australia and NSW. In other words, the deficit against the Interim Reliability Standard identified in the latest ESOO is likely to have already been eliminated by the decisions announced over the last few weeks since the latest ESOO update was published. Furthermore, considering the NSW Government's legislated Electricity Infrastructure Roadmap[21] and its commitment to spend $32bn on electricity generation, transmission and storage by 2030, the capacity surplus above the Interim Reliability Standard will surely continue to expand. In summary, the assertion that KKPS is needed to meet a reliability gap is not true.[22]

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21 https://energy.nsw.gov.au/sites/default/files/2020-12/NSW%20Electricity%20Infrastructure%20Roadmap%20-%20Detailed%20Report.pdf

22 For completeness we note also that in AEMO's 2020 assessment of system strength and inertia shortfalls they do not yet consider a shortfall likely for NSW in the next five years. In this assessment they estimate the retirement of Liddell Power Station in 2023 will not cause system strength or inertia shortfalls. However, the future decommitment or flexible operation of NSW's

4.2 The argument that KKPS will reduce electricity prices is tenuous

In principle, increasing supply in any market can be expected to stimulate competition and hence reduce prices from what they otherwise would be. However we suggest the claim that KKPS will reduce prices is tenuous at best largely because KKPS is highly inflexible (it takes 30 minutes to reach full capacity – it will be even less flexible than Colongra). As set out in the previous section, Colongra's inflexibility explains its poor ability to respond to high prices. KKPS will be in an even worse position since it is even less flexible and also because the market will be settled at 5-minute intervals from 1 October 2021, rather than half-hourly. Thus, KKPS can only hope to be effective in the market when prices are sustained at high levels for long continuous periods. As we set out in the previous section, we concluded that this has been, and will continue to be, rare.

4.3 KKPS's cost is underestimated

Neither Snowy Hydro nor the Government has provided an estimate of the total cost of the project.

The media has widely reported the cost as $600m. However, the Minister's Press Release does not claim that KKPS will cost $600m to build. Rather, it says that "up to $600m has been committed in the 2021/2022 budget".[23] Perhaps the Government expects that KKPS will cost more than $600m and that subsequent budgets will make provisions for the additional amounts needed.

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synchronous generators at times of low or minimum demand may lead to system strength shortfalls at the Newcastle and Sydney West fault level nodes. In AEMO's 2020 assessment they do not consider the supplies of strength or inertia from a new 50 MW battery in Western Sydney22 or the 700 MW battery planned to be installed in the Newcastle region22 which could help eliminate the shortfalls.

[23] We have reviewed the 2021/2022 budget and can not find a reference to the Kurri Kurri project. Notably, the Section "Improving energy affordability and reliability" does not identify any provision had been made to fund KKPS.

The EIS mentions a capital outlay of $610m for a gas-fired power station "up to 750 MW", electrical switchyard and associated infrastructure. On its website Snowy Hydro states that "*the proposed project will cost approximately $610m*" but later in the same document it estimates " *… $800 million worth of investment in the Hunter economy*" as a result of the project.

The estimate of OCGT build costs used by AEMO in the preparation of their ISP assumes capital costs of $1.43m/MW. The recently announced 300+[24] MW Tallawarra B gas generator is claimed to cost $400m[25] ($1.33m/MW), on land which EnergyAustralia already owns and with an existing connection to the electrical grid and which water and gas supply. Another point of comparison is the Mortlake OCGT developed by Origin Energy from 2008 to 2012, and which uses the same Type F turbines planned for KKPS. Mortlake Power Station cost $810m for 550 MW[26] ($1.47m/MW).

Applying the AEMO estimated outlay cost for a 660 MW OCGT station gives an indicative cost of $930 million.

Bringing these strands of evidence together suggests that the total cost of KKPS (excluding at least $100m for gas pipeline development – see below) will be around $1 billion.

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[24] On its website, EnergyAustralia say that the capacity of Tallwarra B is 300+MW

[25] Other amounts - $450m are also cited. See for example https://www.power-technology.com/projects/tallawarra-b-power-station-illawarra-new-south-wales/

[26] https://www.afr.com/politics/federal/origin-s-mortlake-power-station-switches-on-20121205-j1dxd]]

4.4 KKPS's capability is over-estimated

KKPS cannot simply connect to the Sydney-Newcastle Pipeline and receive unlimited gas, as implied in the EIS, as there is insufficient gas supply and line-pack (pipeline) pressure. KKPS will need an intermediate storage system to attain even a few hours of continuous operation.

The pipeline/storage connection to Colongra Power Station provides an indication of what may be envisaged.[27] If a similar system to that at Colongra is built (as it surely must be) it would cost over $100 million. This will, at best, enable operation at full capacity for only five hours. KKPS would then need to revert to diesel, at more than double the cost and with much higher greenhouse gas emissions. On-site diesel storage of two 1.75 million litre tanks is described in the EIS. These tanks will contain sufficient energy to allow production for 10 hours per day for three days. Re-filling the tanks will require 70 B-Double tanker deliveries (50,000 litres each).

After exhausting its gas storage, KKPS will take at least a day to recharge, noting it is in a worse location than Colongra, being beyond the end of the Sydney-Newcastle Pipeline. The recharge time for both power stations could well be longer as they would be 'competing' to get gas from the same pipeline.

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[27] The spur pipeline/storage connection from the Sydney-Newcastle Gas Pipeline to Colongra Power Station is described as *"the largest on-shore gas pipeline in Australia"* - Colongra Gas Transmission & Storage Pipeline, Jemena https://jemena.com.au/pipelines/colongra-gas-transmission-and-storage-pipeline- to enable enough gas to be stored to achieve five hours operation. The connection consists of 3km of 354mm pipeline, a dual compressor station to raise the gas pressure from around 3 MPa (Megapascal) to 13 MPa, and a 9km 1067mm diameter high pressure pipeline that includes 2 extra 1km loops to increase the line pack storage. Twin 4.2 MW water bath heaters pre-heat the gas before it cools during pressure reduction for supply into the turbines. This spur pipeline/compressor system can store up to 40 TJ (Terajoules), which is sufficient to run the four turbines at full capacity for five hours (each turbine consumes 8 TJ/hour when running at capacity). Recharging the pipeline storage system takes 22 hours at a maximum rate of 1.8 TJ/hour, provided sufficient gas is available from the Sydney-Newcastle Pipeline. The spur pipeline/compressor storage system was constructed in 2009 at a cost of $104 million.

KKPS is therefore not a "normal" gas power station - it cannot generate for extended periods over multiple days. Instead, its target market is limited by its gas and diesel supply to sporadic operation for at most five hours on gas and intermittent residual operation on much more expensive diesel.

Furthermore, Snowy Hydro claims that KKPS will feature "the latest and most efficient turbines that the world's best manufacturers can offer for the site"[28]. While Type F turbines are slightly (1 percentage point) more efficient than the Type E turbines in Colongra, they are less flexible. Manufacturers, GE say that the Type E turbines have much shorter start times (15 minutes versus 23 minutes for Type F) and much faster ramp rates (68 MW/minute versus 24 MW/minute for Type F)[29]. This suggests that KKPS will be even less flexible than Colongra even before factoring in KKPS's gas supply constraints.

4.5 KKPS will not recover its outlays

As set out earlier, in the period to 2030 the number of periods of sustained high RD is expected to continue to reduce, as it has since 2017. This reflects the expansion of wind generation in particular and behind-the-meter small scale storage.

Growth in the demand for dispatchable capacity in the period to 2030 therefore depends on coal generation closure. Batteries and gas generators will compete to meet this demand. Considering its gas supply and operational limitations, KKPS will not be a supplier of long duration dispatchable capacity (indeed OCGT has never played such a role). KKPS will be competing in the market for short duration capacity (typically less

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[28] Market share data on heavy duty gas turbine in the United States - https://www.power-eng.com/emissions/policy-regulations/the-fall-of-the-f-class-turbine/#gref - shows Type F machine market share peaked in 2010 and was superceded by Type G, H and J machines in 2014.

[29] https://www.ge.com/gas-power/products/gas-turbines/gt-13e2; https://www.ge.com/gas-power/products/gas-turbines/9f

than 4-hour continuous operation). Its main competitor is likely to be 2 and 4-hour batteries, but it has many disadvantages in this competition:

1. KKPS will be competing with batteries in a market that is settled in 5 minute intervals. Batteries can respond to dispatch instructions in milli-seconds. By comparison the EIS makes clear that KKPS will take 30 minutes from dispatch instruction to full production.
2. AEMO estimate 2/4-hour battery capital costs at $1.1m per MW/$1.7m per MW now and $0.6m per MW / $0.9m per MW by 2030. It is already cheaper to build a 2-hour battery than KKPS today and will be cheaper to build a 4 hour battery rather than KKPS well before 2030.
3. Batteries will be able to charge during the many 5-minute periods in which prices are close to zero or often negative. This means batteries can be expected to have insignificant (or even negative charging costs). This means that they can be expected to run with much higher capacity factors than KKPS. Indeed this is reflected in AEMO's modelling where grid-scale batteries operate at capacity factors of around 10% from 2025.

For these reasons it seems unarguable that batteries will out-compete KKPS in dispatch. Considering their comparable capital costs now (and predicted much lower capital costs in future) and their likely much higher capacity factors, two hour batteries will be financially viable with prices that around 1/6th of those required to ensure that KKPS is able to recover it capital outlays. The inevitable conclusion is that KKPS has no chance in competing effectively with batteries and so can not expect to generate revenues that come anywhere close to those needed to recover its outlays.

5 Conclusions

The main conclusions in this paper are:

1. The Government's claim that the Australian Energy Market Operator (AEMO) has substantiated the need for KKPS to fill a 1,000 MW supply gap when Liddell closes in 2023, is not true. AEMO forecasts no shortfall of dispatchable generation in NSW. In addition, recent battery and generation commitments since AEMO's latest study have further increased the supply surplus.
2. The claim that KKPS will reduce prices is tenuous. In principle, greater supply has the potential to reduce prices in any market. But KKPS is inflexible and slow to respond, taking 30 minutes to reach full capacity from start-up (even slower than Snowy Hydro's existing Colongra gas generator). Its inflexibility will render it useless in most circumstances in the coming 5-minute settlement market (October 2021).
3. Peak Residual Demand (the Operating Demand less renewable generation) is declining sharply. If AEMO's coal closure and storage expansion assumptions are correct, there is no demand for long duration peaking gas generation in the period to 2030. Consistent with this, AEMO's Integrated System Plan (ISP) envisages that NSW's peaking gas generation will together produce electricity for just 4 hours per year in the period to 2030 (in the Central Scenario) or 13 hours per year (in the Fast Change scenario).
4. Using AEMO's build cost assumptions (and the demonstrated build cost of gas generators) KKPS is likely to cost at least 50% more than the $600 million that the Government has provided in the 2021/22 budget.
5. KKPS has been proposed as a source of long duration dispatchable capacity. But KKPS will have a limited supply of gas and its back-up diesel will be prohibitively expensive (and polluting). KKPS, like Colongra, is unlikely to be capable of running (at capacity) on gas for more than about five hours and it will then will take a day or so for its gas supply to recharge.

We conclude that there is at best a tiny market for the sort of service that KKPS can offer and so it has no prospect of earning anywhere near the revenues needed to recover its outlay.

Perhaps AEMO (and we) are wrong and there will be a demand for long duration storage soon. But this does not imply a demand for gas generators such as KKPS. Even if it costs twice as much per MW to build an eight hour battery than to build KKPS (as it does today), an eight hour battery is still more likely to be viable than KKPS. This is because batteries are much cheaper to operate and are much more flexible. Long duration batteries will therefore be able to meet fleeting demand for long duration storage and also compete effectively in the (dominant) short duration storage market. By comparison, gas generators' much higher operating cost and much lower flexibility will inevitably have them on the sidelines in the short duration market, leaving only the rare long duration events in which they might hope to compete.

APPENDIX A

Table E1. NSW hydro and pumped hydro generation from Jan 2017 – April 2021

	Tumut 3 Power Station	Tumut Power Station	Shoalhaven Power Station	Blowering Power Station	Guthega Power Station	Hume (NSW) Hydro Power Station
Technology type	Hydro - Gravity	Hydro - Gravity	Hydro - Gravity	Hydro - Gravity	Hydro - Gravity	Hydro - Gravity
Maximum Capacity (MW)	1800	616	240	80	60	29
Capacity factor (%)	3.8	23.2	6.5	24.6	24.7	50.9
Volume weighted average price received when dispatched ($/MWh)	202.4	97.9	141.2	83.3	86.3	78.8
Percentage of time synchronised (%)	15.59	46.94	11.94	59.29	37.9	61.97
Average dispatch (MW)	365.09	304.21	131.51	33.24	39.07	23.83
Average time synchronised per start-up (hours)	2.72	5.49	2.83	449.94	10.93	163.01
Max time continuously synchronised (hours)	28.08	164	17.08	1879.75	820.75	1683.25
Number of starts	2172	3245	1599	50	1316	144

Table E2. NSW OCGT operation in 2020

	Colongra Power Station	Uranquinty Power Station	Hunter Valley Gas Turbine
Technology type	OCGT	OCGT	OCGT
Maximum Capacity (MW)	724 (non-summer)	664	50
Capacity factor (%)	0.9	2.1	0.2
Volume weighted average price received when dispatched ($/MWh)	805.9	335.4	2240
Percentage of time synchronised (%)	3.06	5.07	0.43
Average dispatch (MW)	216.28	274.69	20.22
Average time synchronised per start-up (hours)	2.8	4.3	1.3
Max time continuously synchronised (hours)	15.1	16.8	6.5
Number of starts	96	104	29

Table E3. NSW hydro and pumped hydro operation in 2020

	Tumut 3 Power Station	Tumut Power Station	Shoalhaven Power Station	Blowering Power Station	Guthega Power Station	Hume (NSW) Hydro Power Station
Technology type	Hydro - Gravity	Hydro - Gravity	Hydro - Gravity	Hydro - Gravity	Hydro - Gravity	Hydro - Gravity
Maximum Capacity (MW)	1500	616	240	80	60	29
Capacity factor (%)	4	24.4	7.6	14.4	30.7	36.2
Volume weighted average price received when dispatched ($/MWh)	269.4	82.3	144.7	69.1	66.4	63.4
Percentage of time synchronised (%)	15.07	55.5	10.64	37.48	42.91	53.41
Average dispatch (MW)	397.08	270.52	170.71	30.66	42.92	19.67
Average time synchronised per start-up (hours)	3.2	8	2.86	206.67	10.44	134.14
Max time continuously synchronised (hours)	16.5	163.5	11.67	527.42	234.92	713.83
Number of starts	414	607	327	11	361	32

Figure E1. Distribution of continuous production duration (hours) per synchronisation in 2020

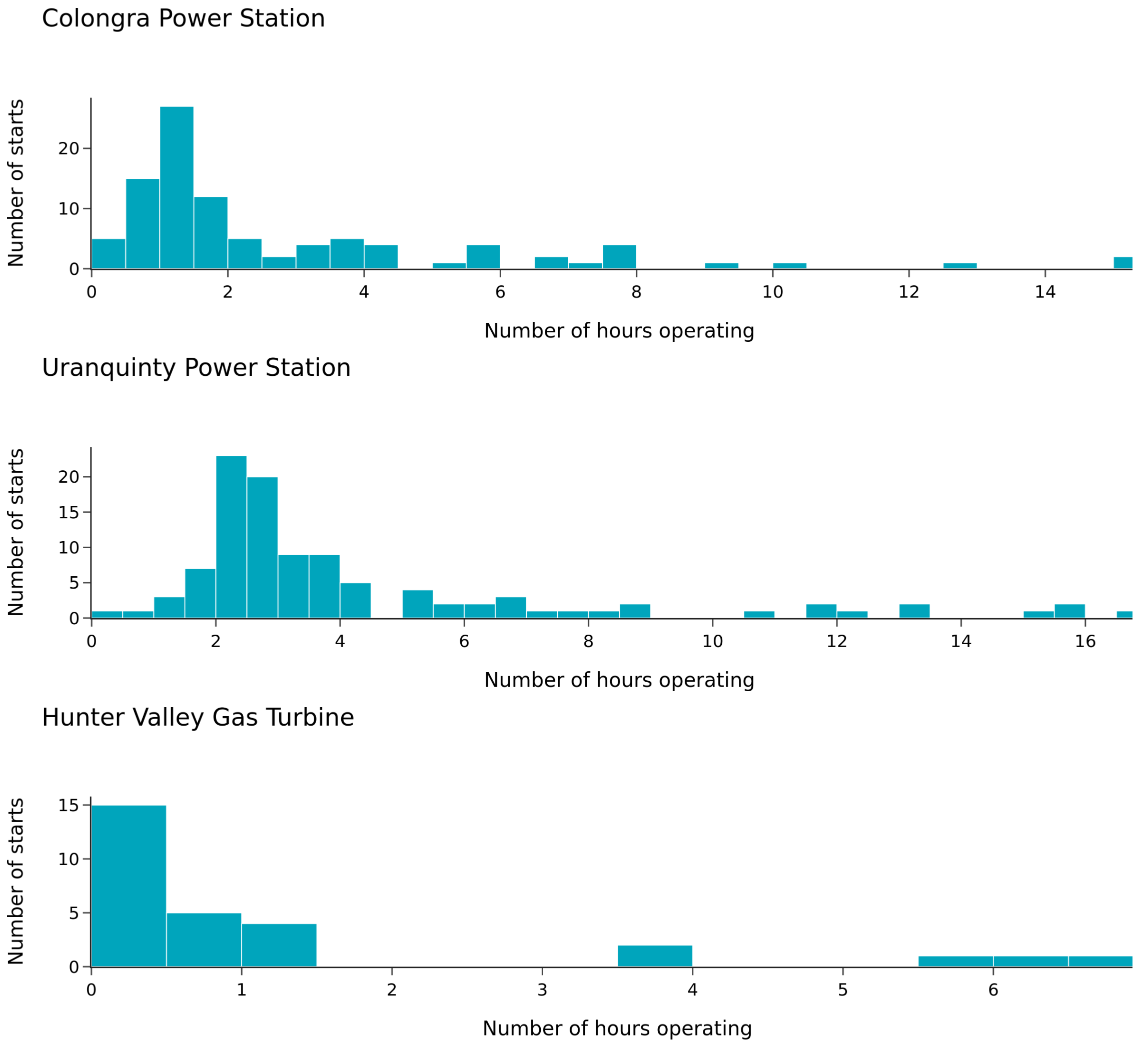


Figure E2. Flow on the NSW-QLD Interconnector

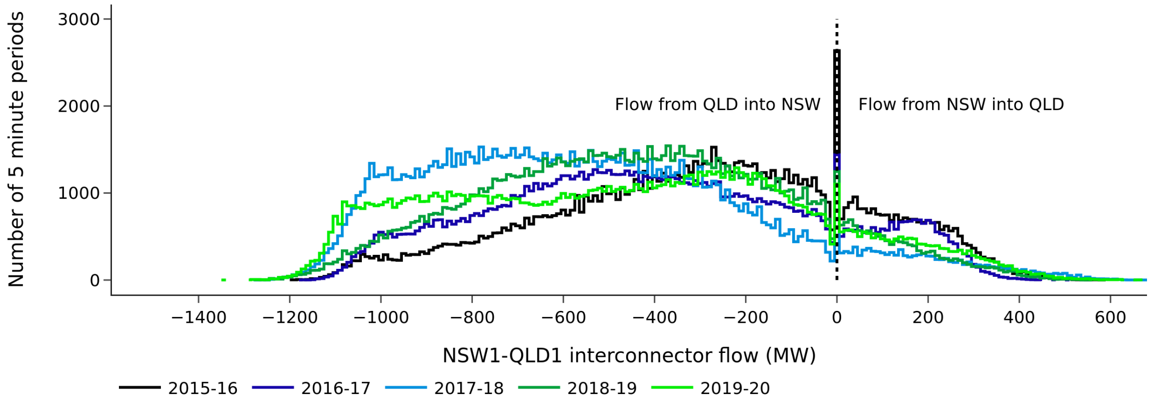


Figure E3. Flow on the VIC-NSW Interconnector

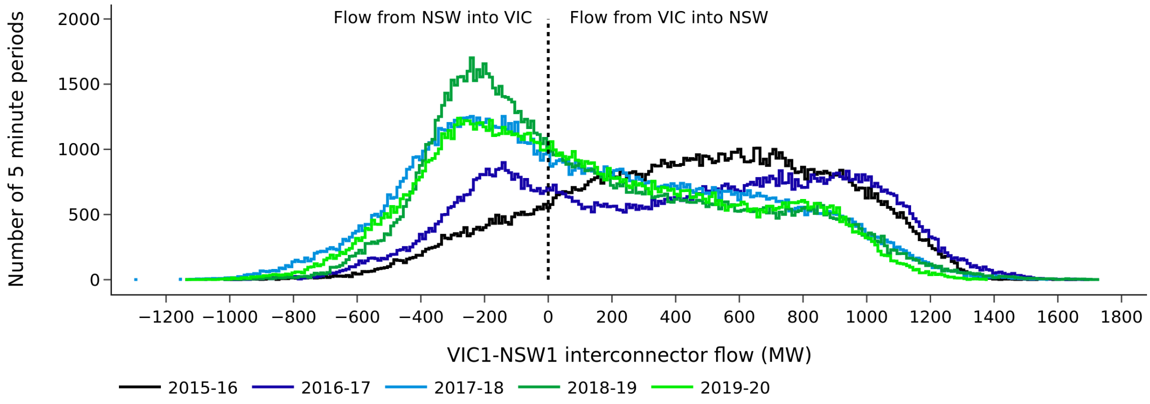


Figure E4. Flow on the VIC-NSW Interconnector

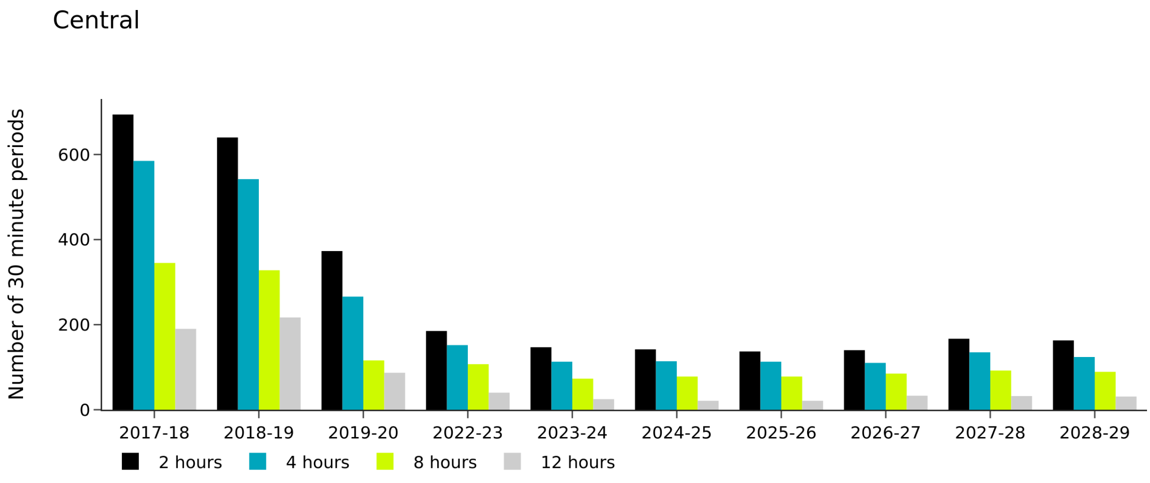


Figure E5. Spot price during highest Residual Demand days in 2020

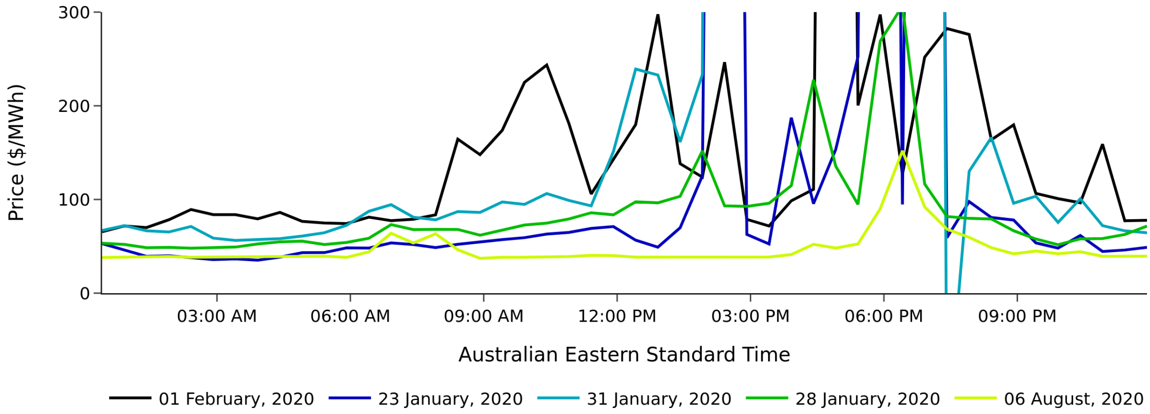


Figure E6. Uranquinty Power Station generation during highest Residual Demand days

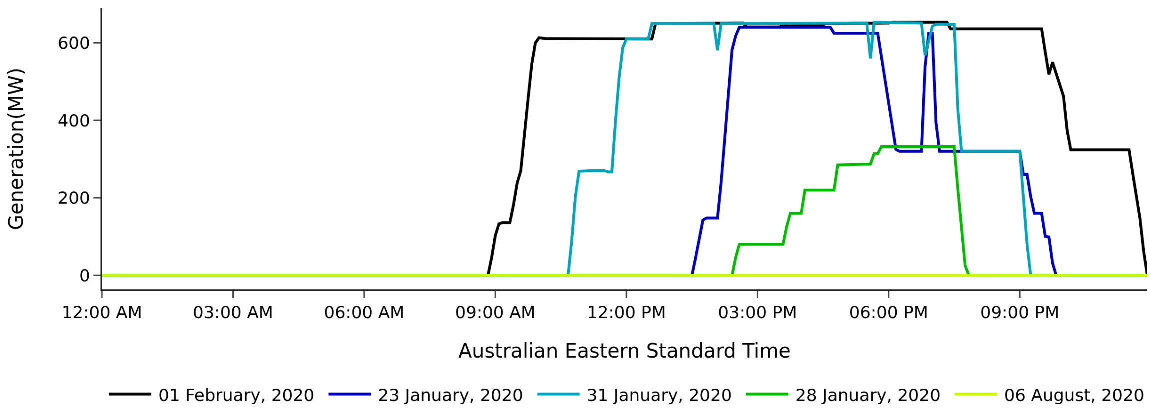


Figure E7. Hunter Valley Gas Turbine generation during highest Residual Demand days

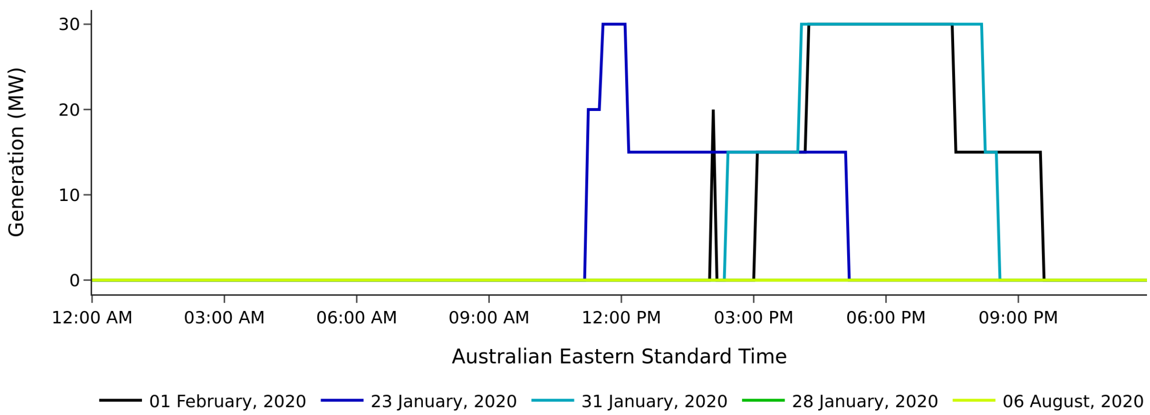


Figure E8. Volume weighted average quarterly NSW ASX cap contract price.

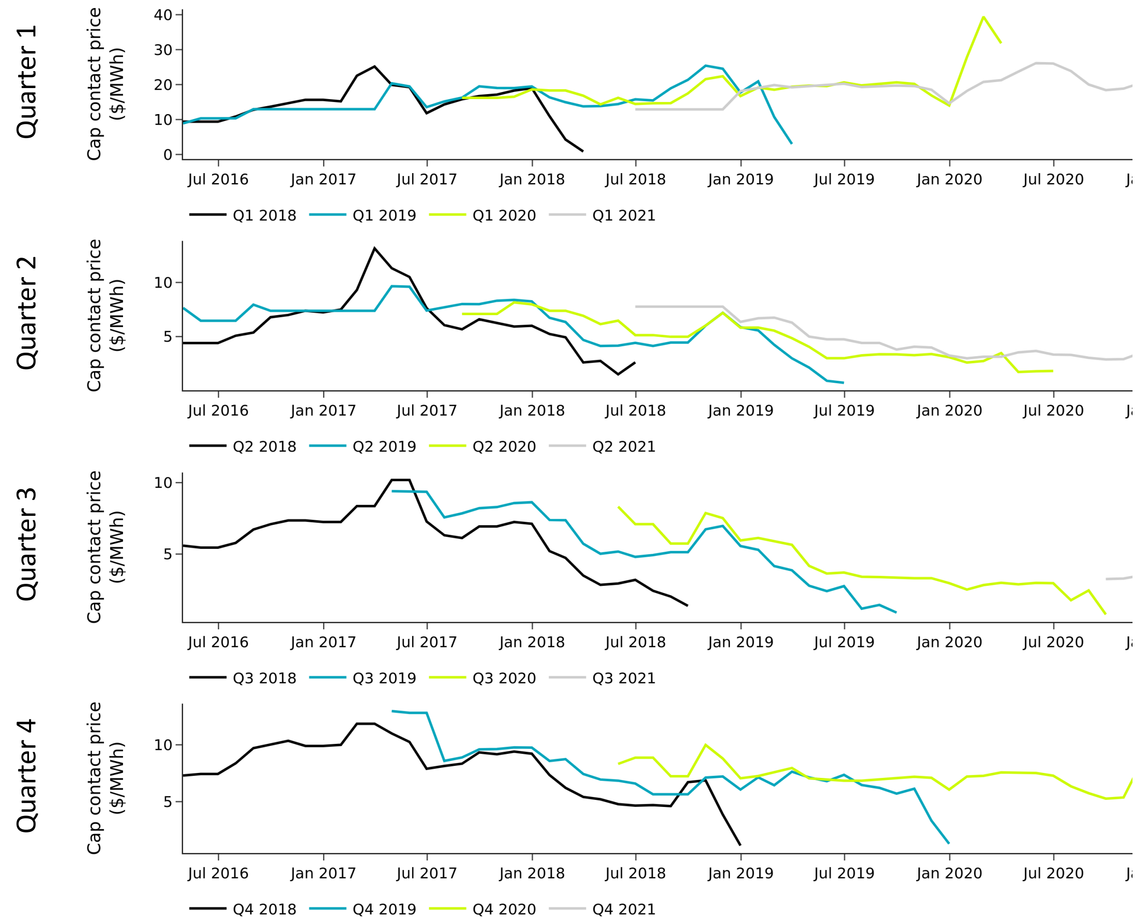
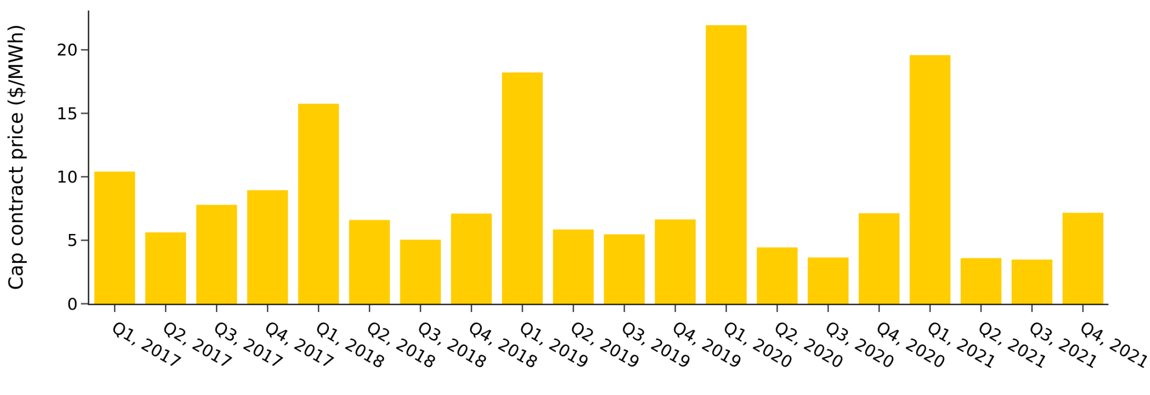


Figure E9. Volume weighted average quarterly NSW ASX cap contract price.



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