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The Role of Low Emissions Dispatchable Power Generation in the Lowest Cost Net Zero System

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IEA Greenhouse Gas R&D Programme

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THE ROLE OF LOW EMISSIONS DISPATCHABLE POWER IN THE LOWEST COST NET ZERO SYSTEM

This study, undertaken on behalf of IEAGHG by Red Vector and Gamma Energy Technology, explores the interdependencies of different power generation technologies in a highly decarbonised future. Most modern electricity grids around the world are now progressing along the decarbonisation journey to deliver reliable, affordable and low carbon power – and with that transformation comes attendant challenges. While there are differing views on the roles particular technologies might play in the grid of the future, interdependencies between technologies are particularly influential in achieving the mix of technologies that maintains grid reliability while meeting net-zero emissions at lowest total system cost.

Key Messages

- The global energy transition to net-zero CO_2 emissions is proving to be a greater challenge than many had previously imagined. The many conflicting international, national, regional, and local priorities make planning for a net-zero future a demanding task.
- To transition to net-zero CO_2 emissions from electricity generation will be a complex challenge. The selection of technologies that will deliver the lowest cost net-zero future while maintaining a reliable grid will be crucial. Not all electricity grids will meet net-zero emissions within the timescales required and will require negative emission technologies or processes to compensate.
- Supplying electricity is but one of many services that technologies provide to the grid, and this needs to be recognised in how technologies are valued and costed. As well as generating electricity, some technologies provide a range of additional grid services that are essential for maintaining a permanent and stable electricity supply. Focusing only on a technology's ability to deliver electricity could well lead to the dismissal of technologies critical to a functioning, lowest cost system.
- In a grid with a growing penetration of variable renewables,[1] there is an increasing requirement on system operators to have access to frequency response, inertia, reserve capacity and other grid services – and fossil-based generation, the conventional sources of these services, is gradually being displaced.
- Modelling the electricity grid has gained importance in recent years given the transformational change required to reduce CO_2 emissions. Electricity system models are important tools, employed to develop and test the implications of possible future scenarios. For example, as generation from variable renewable technologies grows, modelling is required to consider matters such as additional transmission capacity, back-up supply for renewable droughts and grid stability. Policymakers and other key stakeholders often rely on outputs from these models to inform their decisions.
- Historically, the levelised cost of electricity[2] (LCOE) has been the metric most often used for evaluating the relative merits of different generation technologies. While it remains a useful metric for comparing the relative merits of homogeneous generation technologies that offer the same ancillary services (i.e. maintaining system frequency and voltage, reserve capacity and providing an ability to restart the system from a total/partial shutdown), as the generation mix diversifies,

[1] Note that the cost of renewables includes the cost of grid enhancements needed to connect new renewables. For small penetrations this is negligible, but it is relevant in high renewable scenarios. Electricity storage costs are accounted for separately as batteries and pumped storage are separate options with their own CAPEX and OPEX.
[2] The levelised cost of electricity may also be referred to synonymously as the levelised cost of energy. Note also that, at times in the main report, the authors have used the terms 'electricity' and 'energy' interchangeably

LCOE is no longer an adequate metric considering the heterogeneity of services provided by the new portfolio of technologies. To address these failings, several LCOE variants have been proposed. However, by retaining a levelised cost approach, shortcomings remain.

- An alternative approach is to calculate the total system cost (TSC). TSC is gaining traction as a more appropriate cost metric for a changing grid. Currently, only a few within the modelling community focus on TSC and on delivering a decarbonised system that minimises cost to the consumer. TSC is the metric that reflects most closely the price paid by the consumer for the power they consume.

- Modelling Energy and Grid Services[3] (MEGS) is the modelling tool employed for this study. It explores the decarbonisation of power systems at lowest TSC. It is a regional electricity system model that not only ensures there is sufficient firm capacity to meet demand but also that the grid operator has sufficient services to maintain grid supply and stability.

- Subject to maintaining a secure grid and meeting CO_2 emissions limits, the minimisation of TSC is the primary concern in both the short and long-term planning horizons. It is also important to note that MEGS remains free from policy constraints, making it a transparent exercise to estimate the lowest TSC. The impact of policy and regulation on the lowest TSC may then be explored as required.[4]

- The model was used to investigate the interdependencies of different power generation plants in a highly decarbonised future. The role of fossil and biomass generation (with and without CCS), alongside other technologies important for a zero-carbon future[5], was examined via case studies that focused on Australia and Japan.

- While focusing on the lowest TSC opportunities, the analysis showed that:
  - There were viable scenarios for a net zero 2050 electricity grid.
  - All decarbonisation solutions for transitioning to a decarbonised grid were more expensive than today’s grid.
  - While all technologies would need to be available for decarbonisation, CCS was central to the optimum solutions available. Without CCS, especially BECCS to create negative emissions, it was difficult to approach full decarbonisation at a reasonable cost.
  - The modelling demonstrated a clear lowest cost frontier that, as it approached net zero, became increasingly expensive.
  - The analysis demonstrated clearly that, from a technical standpoint, renewables alone cannot be used to achieve net zero.

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[3] As well as balancing energy on an hour-by-hour basis MEGS ensures that there is sufficient frequency response and fast acting reserve, inertia and firm capacity to meet peak demand. Additionally, MEGS also models flows between interconnected regions, weather effects on renewables and demand and ensures short and long term storage is run optimally against weather forecasts of limited accuracy.

[4] Exploring the impact of policy and regulation was not included in the scope of this study. Thus, for example, nuclear power is considered as a technology option in Australia, a country in which generating power from nuclear is currently banned.

[5] In the two jurisdictions covered, Australia and Japan, each low-carbon technology has its detractors and must overcome challenges for it to be deployed. CCS is untried at scale; nuclear is currently banned in Australia; biomass resource must be sustainable; renewables suffer from intermittency, plus wind and solar droughts; batteries are only suitable for short-term storage; hydrogen presents challenges with handling and is untested; and pump storage is limited by geography. Depending on the jurisdiction, its policies and regulations, a technology may not eventually be deployed and others may deliver only in part. However, to meet net zero, it is implausible that all these technologies fail to deliver. Fossil-CCS, BECCS, nuclear, wind, PV and batteries were all modelled for this study. Some long-term storage options were included as part of a high renewables case study.

- A lowest cost solution without BECCS would be very expensive.[6]

- Australia:
  - The lowest cost solution to reach net zero in 2050 had about half of its electricity generated from renewables, predominantly from wind and solar PV.
  - Around a quarter of the electricity was being generated by firm, dispatchable, low carbon capacity such as nuclear, fossil fuel-based CCS and BECCS.
  - The work did not seek to differentiate between the capabilities of gas-CCS and coal-CCS. Selection would ultimately depend on the relative prices at which gas and coal could be procured.
  - At least some BECCS is required to offset unabated emissions, otherwise the system cannot achieve net zero and is significantly more expensive.
  - The second case, with only renewable technologies on the grid to 2040 and all options available thereafter, came at a cost. Compared to the lowest cost solution, i.e., with no technologies prohibited, reaching net zero by 2050 raised the cost by AUD$ 10/MWh.
  - There is considerable uncertainty within the BECCS and CCS capital cost estimates, given none of these technologies has been constructed in Australia.

- Japan:
  - The lowest cost solution for net zero in 2050 had about half of its electricity generated from firm, low-carbon capacity.
  - Nuclear had a critical role, as did BECCS. BECCS was a critical carbon offset technology to enable net zero.
  - Given the lack of shallow waters, the low land availability and the poor load factors (and, hence, economics), both offshore and onshore wind were ruled out.
  - Hydrogen[7] storage was found to be uneconomic under the current cost considerations.
  - Removing nuclear as a technology option significantly increased the lowest TSC.

Background to the Study

The global energy transition to net-zero CO_2 emissions is proving to be a greater challenge than many people had previously imagined. The many conflicting international, national, regional, and local priorities make planning for a net-zero future a demanding task. Plus, there are differing views on the roles particular technologies might play in the grid of the future. Independent studies, using different assumptions and, moreover, focusing on different questions, arrive at seemingly conflicting views of the future.

Realistically, transitioning to net zero will require nothing less than a complete and radical transformation of all processes that emit greenhouse gases. Even then, not all processes could reach

[6] In broad terms, the analysis indicated that:
- Net zero could not be reached using only renewable technologies, some dispatchable (fossil) power would be required
- Power-CCS can reach high capture rates, approaching 100%. However, as the capture rate reaches high values, say >98%, the cost begins to escalate.
- So, to reduce both cost and the consequent residual CO_2 emissions, BECCS is required.
- That is, for the regions explored (Australian NEM and Japan), the analysis showed a lowest cost solution without BECCS would be very expensive.

[7] For this study, only hydrogen was considered as a carrier, in part due to the Japanese interest in the HESC project in Victoria, Australia. The lack of low emissions production pathways for other carries at scale, including LOHCs and ammonia, and the scarcity of reliable cost and performance data was also a factor in considering only hydrogen. It was noted that other authors expect ammonia and hydrogen to be the bulk commodity carriers. As mentioned in the main report, given the importance of hydrogen in the Japanese decarbonisation strategy and energy diversification more broadly, further work is recommended to explore the cost and availability of hydrogen, ammonia and other hydrogen storage options within the Japanese and Australian contexts.

zero emissions and will require negative emission technologies or processes to compensate. Selecting the technologies that will transition from the present and deliver the lowest cost net zero future will be crucial. All this points to a complex challenge, not least for the electricity sector.

Modelling the electricity grid has gained importance in recent years given the transformational change required to reduce CO_2 emissions. Electricity system models are critical tools that policymakers and other stakeholders utilise to develop and test the implications of possible future scenarios. For example, as generation from variable renewable technologies grows, modelling is required to consider aspects such as additional transmission capacity, back-up supply for renewable droughts and grid stability.

Supplying electricity is only one of the many services that technologies provide to the grid, which needs to be recognised in how technologies are valued and costed. As well as generating electricity, some electricity generation technologies provide a range of additional grid services that are essential for maintaining a permanent and stable electricity supply. Such services include reserve capacity, voltage and frequency control. Nuclear, coal, gas, solar photovoltaic (PV), solar thermal, wind and geothermal, for example, each have its advantages and disadvantages, as well as offering different services to the electricity grid. Not considering the whole system can result in key decision makers using misleading information. Technologies would be judged solely on their ability to deliver electricity, rather than their ability to lower TSC – an approach that could well lead to the dismissal of technologies critical to a functioning, lowest cost system.

A conceptual representation of TSC is shown in Figure 1. Electricity system assets are shown within the system circle in the diagram and refer to physical parts of the system, such as generators and grid facilities. Costs refer to any payments that leave the electricity system, such as OPEX shown by blue arrows, or taxes shown by green arrows. However, these costs exclude exchanges between participants of the system, such as a generator’s grid connection fees or the system operator’s payments for grid services shown by light blue arrows. The price paid by consumers (or the income), either directly or indirectly (orange arrows), must cover all these outgoings and, hence, is equal to the TSC.

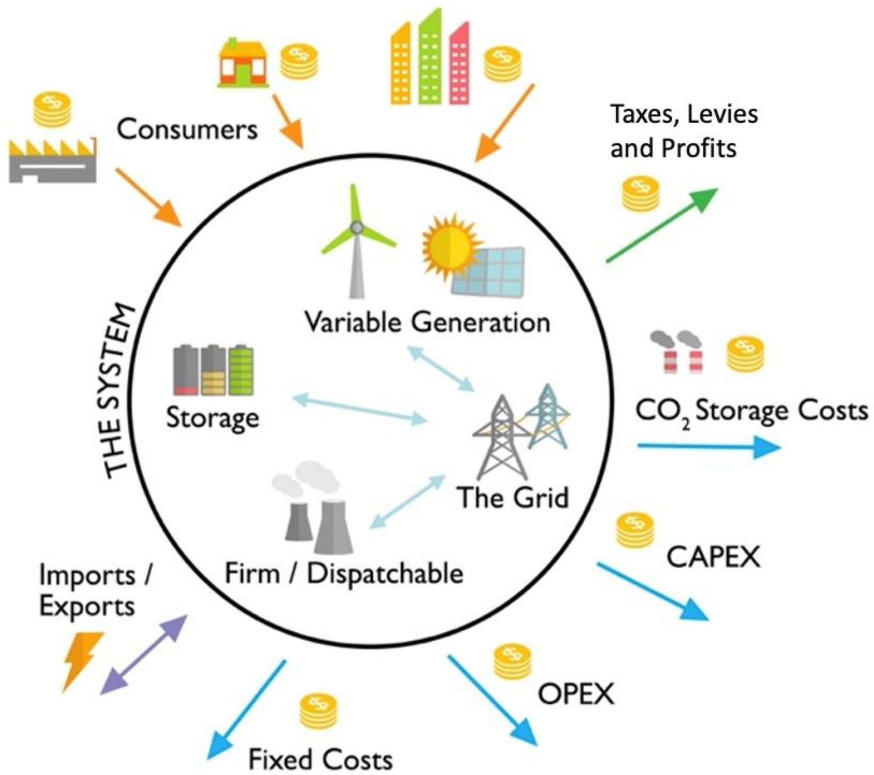

Figure 1: Derivation of total system cost as a function of external financial exchange

Historically, LCOE has been the metric most commonly used for evaluating different generation technologies. While it remains a useful metric for comparing the relative merits of generation technologies that offer the same services, as the generation mix diversifies, LCOE becomes less useful. To address these failings, several LCOE variants have been proposed. However, by retaining a levelised cost approach, the shortcomings largely remain.

An alternative approach is to calculate the TSC. TSC is gaining traction as the most appropriate cost metric for a changing grid. Currently, only a few within the modelling community focus on TSC and on delivering a decarbonised system that minimises cost to consumer. Only by looking at TSC, however, is it possible to understand the total cost to the consumer.

Modelling Energy and Grid Services[8] (MEGS), the modelling tool employed for this study, explores decarbonisation of power systems at lowest TSC. It is a regional electricity system model that not only ensures there is sufficient firm capacity to meet demand but also that the grid operator has sufficient services to maintain grid supply and stability. This is important as, in a grid with a growing penetration of variable renewables, there is an increasing requirement on system operators to have access to frequency response, inertia, reserve capacity and other grid services – and fossil-based generation, the conventional sources of these services, is being displaced.

MEGS recognises the pre-existence of a grid and reports on the economic value of adding a new power generation asset to that grid. Once installed into the system, a suboptimal technology mix cannot easily be addressed. Subject to maintaining a secure grid and meeting CO_2 emissions limits, the minimisation of TSC should be the primary concern in both the short and long-term planning horizons. The model remains free from policy intentions, making it a transparent system cost minimisation exercise. Policy and regulation measures then become options that may be interrogated as case studies.

Scope of Work

The aim of the study was to investigate the interdependencies of different power generation technologies in a highly decarbonised future. The interdependencies were investigated while finding the lowest cost way to achieve net zero and, at the same time, maintaining grid security.[9] This required examining the role of fossil and biomass generation (with and without CCS) alongside other technologies important for a zero-carbon future.

Finding the generation mix with the lowest TSC for deep levels of decarbonisation is critical for electricity consumers and taxpayers, who together need to cover the costs of the entire electricity system. A future system must maintain system security and "keep the lights on". The modelling, based on MEGS, ensured that the technical constraints of a secure and competent grid were met. As well as meeting demand at each sequential time step, MEGS models grid services, such as firm capacity, inertia, and frequency response, ensuring that there are sufficient volumes of these balancing mechanisms available to the grid operator.

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[8] Modelling Energy and Grid Services (or MEGS) is an electricity system scenario tool designed to explore options to approach the optimal mix for a particular decarbonisation target.

[9] While the dynamics of stochastic events were not modelled (as they were outside the study's scope), adequate security to withstand shocks to the system was inbuilt to the model via three mechanisms:

- Sufficient inertia was ensured at all times and in all regions to keep the rate of change of frequency (an important quantity that qualifies as the robustness of an electrical grid) within tolerance – as set by the system operator and dependent on the largest loss of load.
- Sufficient response and reserve in each region (which could be imported from neighbouring regions) was available to return frequency within operational limits
- Sufficient firm capacity was present to meet peak demand plus a safety margin (typically 15%).

Having these systems in place modelled good practice and enabled the system operator to manage shocks to the system.

Via three case studies, the analysis sought to demonstrate what opportunities the Australian and Japanese stakeholders would have to achieve a net zero power system at lowest cost by 2050. The first two case studies were based on the Australian National Electricity Market (NEM) – see Figure 2 – with its five Eastern interconnected states. Currently coal forms the backbone for Victoria, New South Wales and Queensland; South Australia has a mix of gas and renewable generation; and Tasmania is hydro dominated.

The first case study focused on finding the lowest cost means of decarbonising the grid by 2050 (given the assumptions made) but with minimal constraints on technology availability. The second case study supposed that, until 2040, there was a drive to decarbonise using renewables alone. Then, after 2040, a policy U-turn was enacted that allowed any technology to be available to the grid from 2040 forward.

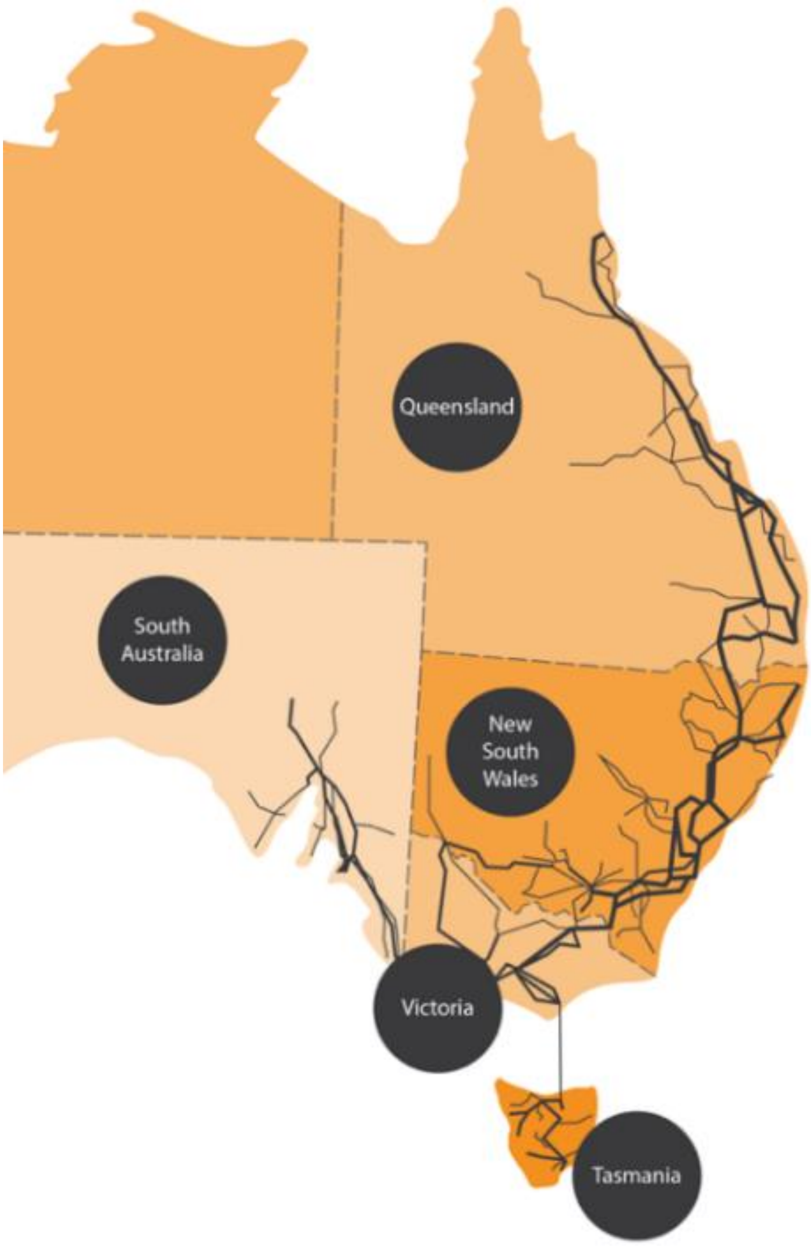

Figure 2: The Australian National Electricity Market

The third case study was based on the Japanese electricity grid, as shown in Figure 3, which comprises two major interconnected systems: the Eastern Japan grid that runs at 50 Hz and is divided into three regions; and the Western Japan grid that runs at a frequency of 60 Hz and is divided into six regions. The two grids have unique characteristics and generation technology compositions, though most regions are supported by a nuclear generation backbone.

Figure 3: The Japanese electricity grid

Findings of the Study

Using the MEGS model, this work demonstrated that there are viable scenarios for a net-zero 2050 electricity grid.

Australia. The characteristics of a net zero electricity grid generation profile for the Australian east coast grid (the NEM) for 2050 were modelled, with the results shown in Figure 4. Examining the lowest

TSC generation solution, with its projected generation profile, some interesting observations may be made:

- The modelled system has a total capacity of over 200 GW of installed capacity.
- Nearly half of the generation in this lowest TSC scenario is from wind and solar PV, with solar PV providing the larger share.
- While there is some curtailed electricity, it is minimal, meaning the generation stack is utilised very efficiently.
- The remainder of the generated electricity is delivered equally by peaking, mid-merit, and firm-low emissions power plants.
- BECCS is an important low carbon generator. Although generating only 10% of total electricity, its negative emissions allow flexible gas (OCGT) to support renewables.
- The remainder of the low carbon generators are divided equally between CCS and nuclear.

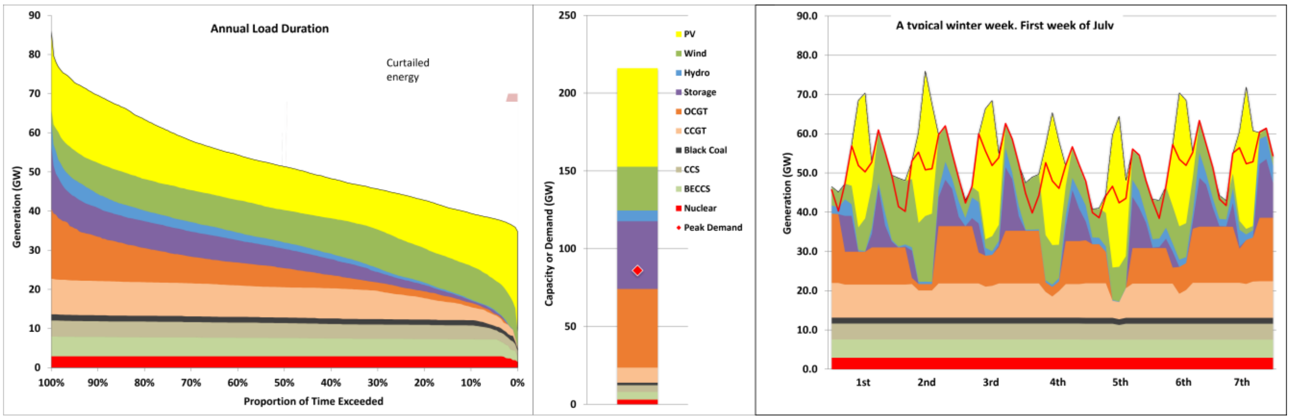

Figure 4: Lowest TSC solution for the Australian NEM in 2050

The impact of a strong push to decarbonise the Australian NEM with just renewables, storage and a significant strengthening of interconnections was also examined. This case was set to reach 90% decarbonisation by 2040 at the lowest system cost, subject to the constraint of renewables being the only low-carbon technology. This case then supposed there was a policy U-turn, allowing all technologies to be available for the final push to net zero by 2050. Even though the grid had been set up to be as renewable friendly as possible, it resulted in no additional renewables being built in the 2040s. Instead, BECCS was built, with some additional unabated gas. However, these U-turn scenarios could not achieve the lowest TSC previously determined.

In summary, renewables will play an important role, as will energy storage. Australia will move from a heavily coal (and gas) generation backbone to an electricity grid mainly based on renewables and gas underpinned by nuclear and fossil-CCS generation, as shown in Figure 5. BECCS facilitates a lowest cost grid, with OCGT systems as backup. OCGT plants ensure the grid can cope with long periods of low generation from renewables during the Australian winter months.

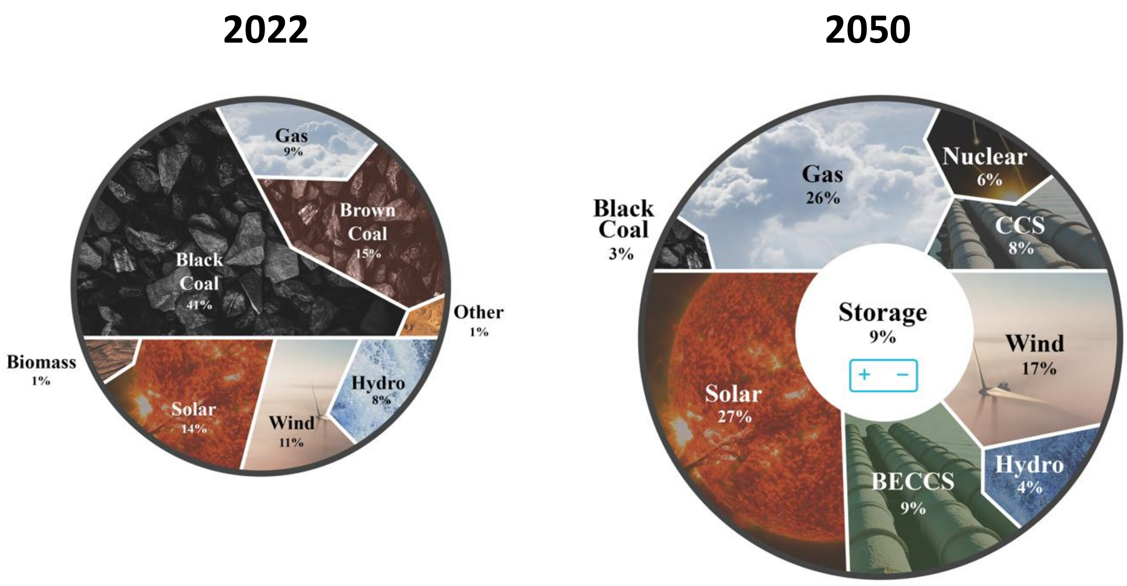

Figure 5: Australia – moving from a high emissions grid to net zero by 2050

Japan. Japan has long realised the sensitivity of its electricity supply and relies on diversification of generation technologies to manage risks. Within the context of a diverse generation portfolio, two scenarios were examined. The first assumes no new nuclear was to be constructed but allowed the current 38 GW to be refurbished and brought back online. The second assumes a nuclear renaissance which allows a further 22 GW of nuclear build on top of the 38 GW of existing nuclear coming back online.

Only the first is covered in this Overview, i.e., where no new nuclear was to be constructed but allowed the current 38 GW to be refurbished and brought back online. Within these constraints the characteristics of a net zero electricity grid generation profile for the Japanese grid for 2050 was modelled, see Figure 6. Examining the lowest TSC generation solution, with its projected generation profile, some interesting observations may be made:

- With no additional nuclear power, the generation capacity of a net zero 2050 would reach 450 GW.
- The firm dispatchable, low emission technologies are BECCS and CCS. A combined total of around 100 GW underpins the grid.
- Gas combined cycle plants also run as near baseload capacity, with open cycle gas operating as peaking plant.
- Renewables play a relatively minor role within the net zero system despite a large installed capacity of solar PV.
- Storage is charged with excess electricity. The system comprises an effective generation portfolio with no curtailed electricity.
- BECCS plays a critical role within the net zero context, offsetting all CO_2 emissions from gas-based plant. BECCS effectively offsets 294 Mt of CO_2.

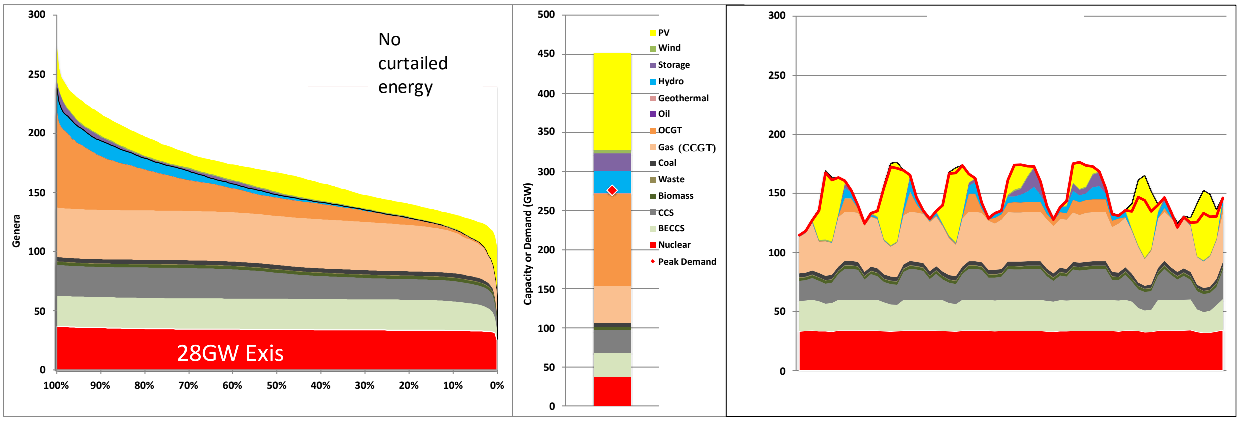

Figure 6: No new nuclear optimal scenario for Japan

In Japan, unabated fossil plants[10] would likely operate in summer and winter delivering peaking duty, given the country has relatively fewer renewable resources than Australia.[11] BECCS, as a negative offset technology, would operate for the majority of the year at a relatively constant load – thus providing a net-zero offset.

In summary, nuclear plays a critical role for Japan in the net zero 2050 lowest cost scenarios, see Figure 7. BECCS also enables a strong back up system of gas generation plants, being able to offset emissions to enable net-zero CO_2 emissions. Japan, having a long tradition of energy diversity, will also rely on coal-based (or maybe gas-based) generation with carbon capture alongside its nuclear fleet. More work is required to examine the role of fossil-CCS generation as an alternative to nuclear.

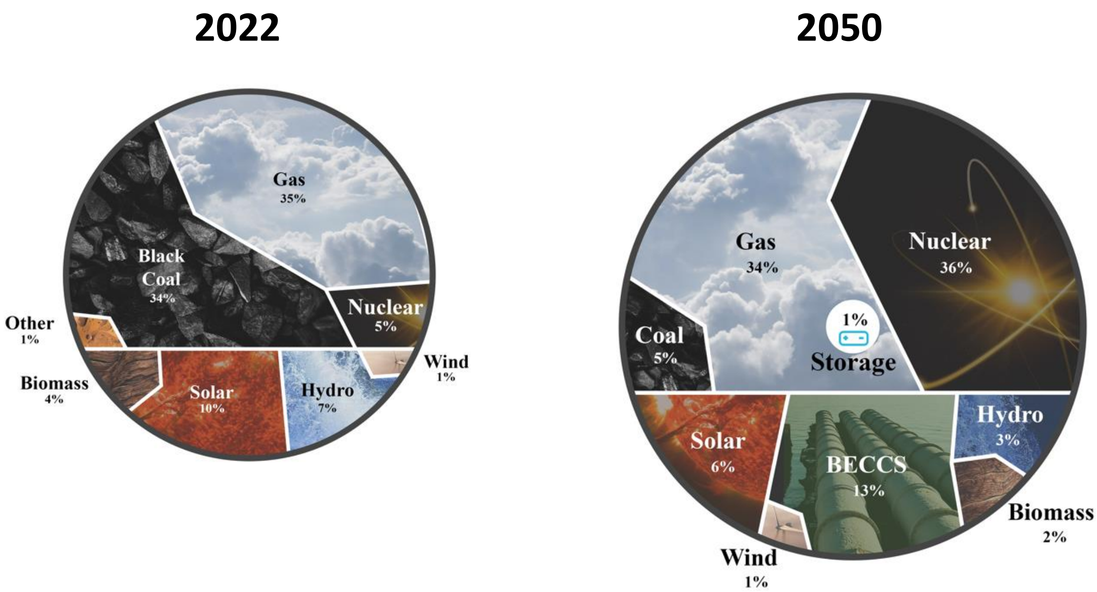

Figure 7: Japan – moving from a high emissions grid to net zero by 2050

Expert Review Comments

Feedback was predominantly positive, with the external reviewers making a range of comments that the authors endeavoured to address in full. While noting that some of the comments referred to matters that lay outside the scope of the report, where substantive points were raised and/or where further

[10] For technical and economic reasons, OCGT and 'peaking' coal plants do not make good candidates for capture.
[11] In Australia, unabated fossil plant would primarily be used for peaking duties and, as such, would likely run more during the winter months, as solar has strong summer performance.

explanation was deemed appropriate, text in the report was expanded or modified. That the modelling aspired to optimise over multiple different scenarios and generation mixes was highly appreciated, with one reviewer stating that:

> "*… the method is outstanding in its ability to communicate complex problems. The graphs of 'proportional decarbonisation versus annual total system cost' are insightful and should be used more.*"

It was put to the authors that some results differed significantly from those found in the 'Net Zero Australia' report.[12] The authors replied that, unlike this study, the Net Zero Australia study did not focus on the lowest TSC but on a wider set of scenarios, with a much broader focus and underpinned by different assumptions. Given that, it was recognised that the findings from both studies exhibited many similarities, e.g., that renewables were important, that there was a need for firm, dispatchable power (much of which was provided by low utilisation OCGT), and that CCS had a role to play. Furthermore, in both studies, unabated gas and battery storage provided important support to a significantly developed renewables portfolio.

It was observed that learning curves for different technologies were not mentioned in the report. The authors explained that the learning curves came directly from the well-regarded data sources used to populate the MEGS model (principally, CSIRO's GenCost and Lazard's LCO+ reports). Both sources provided comprehensive data that unpinned the learning curve work.

In response to an enquiry regarding the cost assumptions for CO_2 transport and storage that were used in the analysis, the authors answered:

> "*The full downstream cost of CO_2 transport and storage used for Australia is AUD$ 15/tonne and is based on the Australian Power Generation Technology Study.*[13] *For Japan a value of USD$ 23/tonne is used based on Lazard's Levelized Cost of Energy Analysis.*[14]"

Given the fraught nuclear debate in Australia, question marks were raised over whether the technology would be deployed there by 2050. With its long construction time, the cost for storage of nuclear waste and its challenges regarding public acceptability, opposition is currently strong. The authors replied that to fully decarbonise electricity grids, the system would need access to firm, low-carbon generation for the periods when renewables were unavailable. The most likely technologies to meet this demand each faced significant barriers in Australia: CCS has not been deployed at scale and CO_2 storage was mostly uncharacterised; biomass has fuel sourcing issues; large-scale energy storage (of the order of TWh) was untried and hydrogen cycles were inefficient; and nuclear was subject to the issues stated.

If Australia[15] were to choose not to deploy nuclear, it would place a lot of expectation on fossil-CCS to deliver, a technology where, as yet, development was not commensurate with a net-zero pathway. Furthermore, the costs of meeting net-zero emissions would be higher – resulting in a significant deviation from the lowest possible TSC – or the target of meeting net-zero would be abandoned.

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[12] A detailed comparison of results with those from other studies, while of interest, lay outside the scope of this study.

[13] CO2CRC. (2015). Australian Power Generation Technology Report. CO2CRC. https://earthsci.org/mineral/energy/coal/LCOE_Report_final_web.pdf.

[14] Lazard. (2023). Lazard's Levelized Cost of Energy Analysis - Version 16.0. https://www.lazard.com/research-insights/2023-levelized-cost-of-energyplus.

[15] In some of their earlier work, the authors had examined the no-nuclear scenario for Australia, which showed that a lot of reliance had to be placed on CCS to deliver net-zero. These results are encapsulated in their online tool, where users can examine any scenario of their choice: https://modelling.energy/MEGS?allCCS=0,0&country=aus&nuclear=0,0&page=charts&version=educational&year=2050.

The authors also observed that, as nuclear was currently receiving a strong push from the Official Opposition in Australia and, as the AUKUS submarine project meant Australia had already placed a foot in the nuclear doorway, it was considered reasonable to explore nuclear alongside other technologies in the 2050 timescale.

The trade-off between food production and the biomass production required for energy production was raised. As was noted in the report, BECCS was a good solution **only if** it could be sustainably deployed at the scales required. Consequently, further work into BECCS and its constraints would be a useful addition to the body of knowledge.

It was observed that some of the headline conclusions appeared to be primarily driven by the input assumptions. The authors agreed that the input assumptions had a significant bearing on the outcomes, as did the research question being asked. They pointed out that results from the analysis were projections and, as such, were scenario dependent. They contended that the use of scatter plots and the examination of constraints enabled the uncertainty role to be explored adequately within the scope of this report.

While it was recognised that demand side management would have an important role to play, it was not included as one of the scenarios within the scope of work. The authors justified this by stressing that demand side management would act in a similar way to batteries and could shift load by a few hours, so would be unlikely to change the result other than, perhaps, displacing some batteries. Regarding long-term storage that could act over weeks, the authors were unaware of any significant longer term energy storage that could be deployed at short notice over this timescale other than, perhaps, hydrogen – but electrolysers were relatively expensive, inflexible and it would not make good sense to part load or shut them down. Hydrogen integration into the power system was considered a topic worthy of further analysis.

Conclusions and Recommendations

A series of modelling runs using the MEGS model were undertaken for the Australian east coast electricity grid (the National Electricity Market – NEM) and the Japanese electricity grid. More than a thousand scenarios for each system were completed, all satisfying the system needs for 2050. A wide range of technologies were deployed in the analysis, including:

- Onshore and offshore wind
- Solar PV
- Battery storage
- Hydrogen storage
- Nuclear
- Coal-CCS
- Gas-CCS
- Biomass CCS (BECCS)
- Unabated coal
- Unabated gas (combined and open cycle)

While focusing on the lowest TSC opportunities, the analysis showed that all decarbonisation solutions for transitioning to a decarbonised grid were more expensive than maintaining today's high-carbon grid. Constraining some of the technology options for this radical transformation increases the overall decarbonisation costs and, in some circumstances, limits the ability to reach net zero at all. It also showed that while all technologies would need to be available for decarbonisation, CCS was central to the optimum solutions available. Without CCS, especially in conjunction with BECCS to create negative emissions, it was difficult to approach full decarbonisation at a reasonable cost.

The modelling exhibited a clear lowest cost frontier that, as it approached net zero, became increasingly expensive. All efforts to reduce carbon emissions in a power grid of the future would come at an increased cost. Hence a major driver for managing this transition will be working towards the best outcome whilst keeping the cost increases as low as practicable. The work has demonstrated clearly that, from a technical standpoint, renewables alone cannot be used to achieve net zero. It has also demonstrated that a lowest cost solution without BECCS would be very expensive.

Australia. Regarding the Australian NEM in 2050, the lowest cost solution to reach net zero had about half of its electricity generated from renewables. The renewables were predominantly wind and solar PV. Around a quarter of the electricity was being generated by firm, dispatchable, low carbon capacity such as nuclear, fossil-CCS and BECCS.

The second case, with only renewable technologies on the grid to 2040 and all options available thereafter, came at a cost. Compared to the lowest cost solution, i.e., with no technologies prohibited, reaching net zero by 2050 raised the cost by AUD$ 10/MWh.

Japan. Regarding the Japanese electricity grid in 2050, the lowest cost solution for net zero had about half of its electricity generated from firm, low-carbon capacity. Nuclear had a critical role, as did BECCS. BECCS was a critical carbon offset technology to enable net zero. Hydrogen storage was found to be uneconomic under the current cost considerations. Removing nuclear as a technology option increased the TSC by USD$ 10/MWh.

Suggestions for Further Work

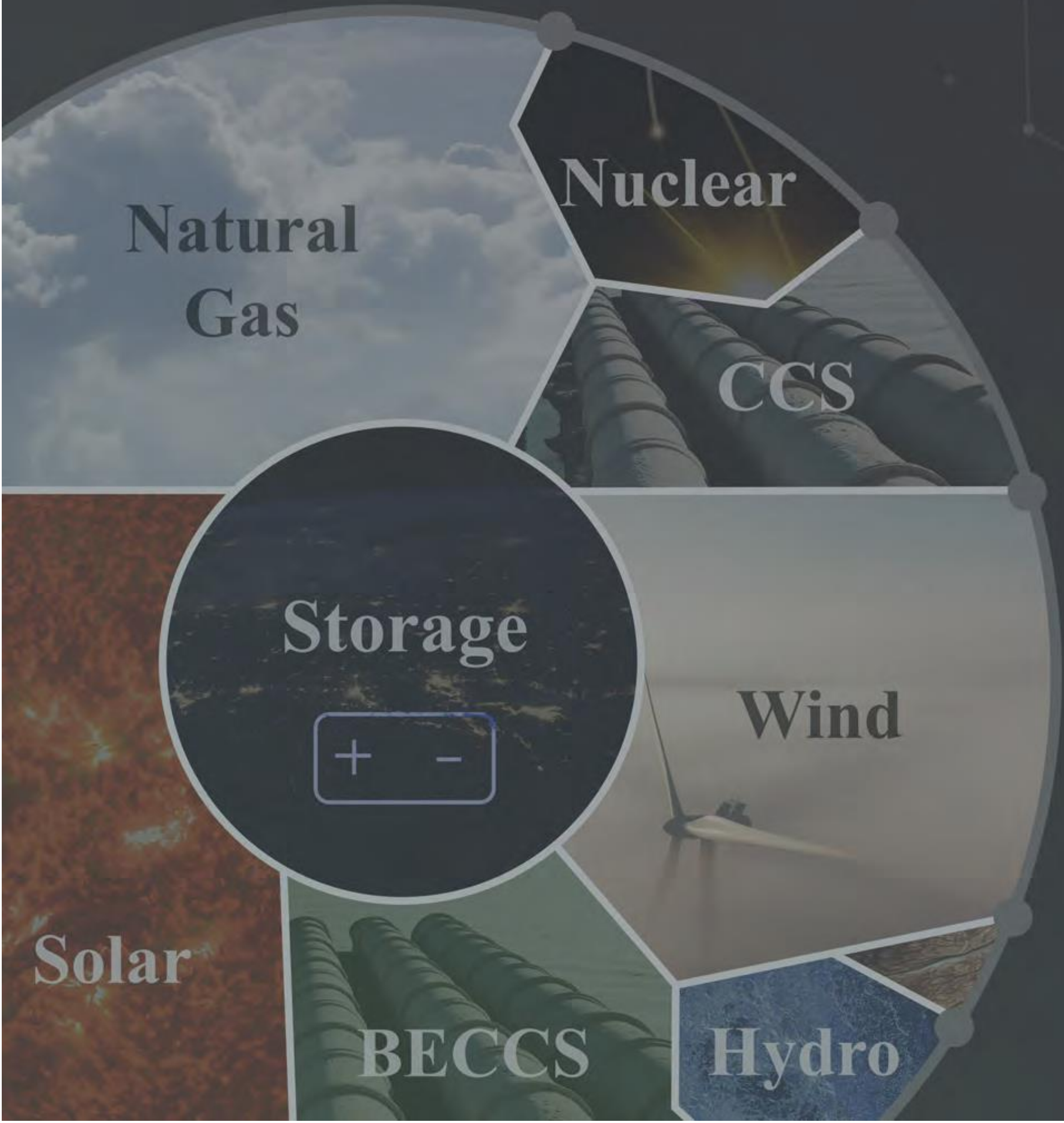
Recommendations for potential follow-up studies include:

- Given the level of interest generated by this study, similar analysis would be of value for other geographical jurisdictions.
- Transitioning to net zero requires significant and disruptive change, radically altering the distribution of system costs and benefits between consumers. Hence, the impact on lowest TSC of sustainability/environmental constraints, e.g., social justice, could usefully be investigated.
- The constraints, restrictions, costs and other assumptions around the use of biomass in BECCS should be tested to understand their impact on future scenarios.
- The cost, practicality and efficiency of hydrogen, ammonia and other hydrogen storage options should be explored further within the Japanese and Australian contexts.
- The constraints and costs of CCS for Japan, and the opportunities for storage, including export, need further characterisation.
- The cost and performance interplay between nuclear and CCS technologies need exploring, including the role and importance of CCS flexibility.
- The constraints and costs for the further development of renewables in Japan need better definition, particularly for onshore and offshore wind.
- This study should be done for other countries such as Korea, Taiwan etc

The Role of Low Emissions Dispatchable Power Generation in the Lowest Cost Net Zero System

Australia and Japan Case Studies

IEA/CON/22/292



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Study Team

The study was led by Red Vector in conjunction with Gamma Energy Technology. The contributors were:

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The team would like to thank Levi Jackson, on placement at Red Vector from Kingsmead School, for initial preparation of the data set for Japan.

Non-Technical Executive Summary

The global energy transition is proving to be harder than many people have previously imagined. The many conflicting international, national, regional, and local priorities are making planning for a net zero future very challenging.

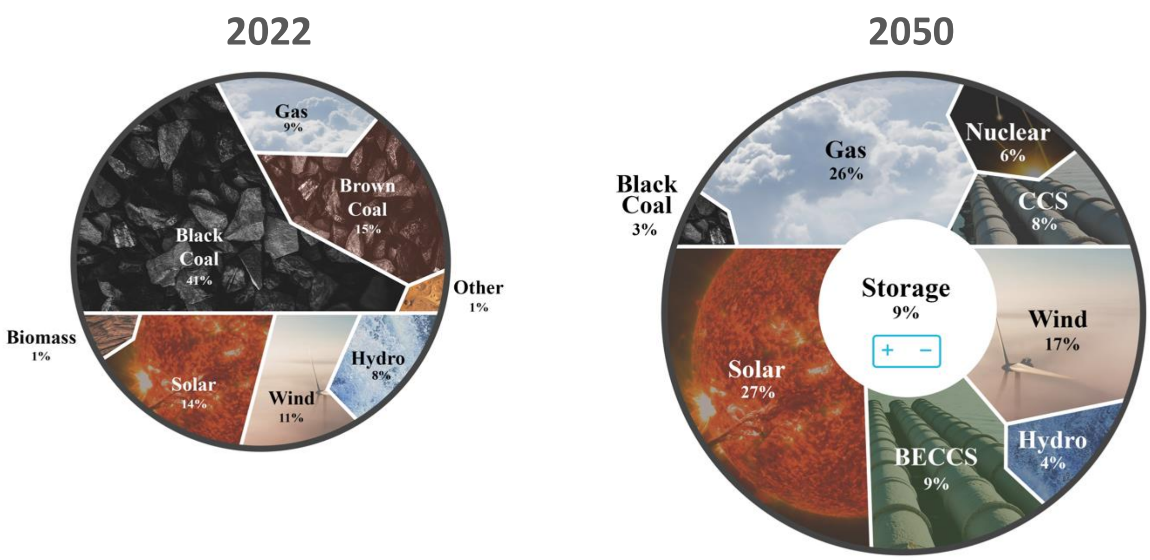
Transitioning to net zero is not just the energy sector endeavour and realistically it will require nothing less than a complete and radical transformation of all processes that emit greenhouse gases. Even so, not all processes can reach zero emissions requiring compensation from negative emission technologies or processes. What this means for the electricity sector is complex. This study looked at some of the characteristics of future scenarios for net zero electricity grids in Australia and Japan.

Importantly, transitioning to a decarbonised grid is more expensive than maintaining the current high carbon grid. Constraining some of the technology options that may be available for this radical transformation increase the overall decarbonisation costs, and in some circumstances, limit our ability to get to net zero at all.

This work, focusing on a lowest total systems cost approach, has demonstrated that there are viable scenarios for a net zero 2050 electricity grid.

Focusing on the Australian East Coast grid (the NEM), renewables will play an important role, as will energy storage. Australia will move from a heavily coal (and gas) generation backbone to an electricity grid mainly based on renewables and gas underpinned by nuclear and fossil fuelled generation with carbon capture and storage. Biomass, in conjunction with carbon capture and storage facilitates a lowest cost grid, enabling gas-based backup systems. These gas generation plants ensure the grid can cope with long periods of low renewables – the Australian winter months.

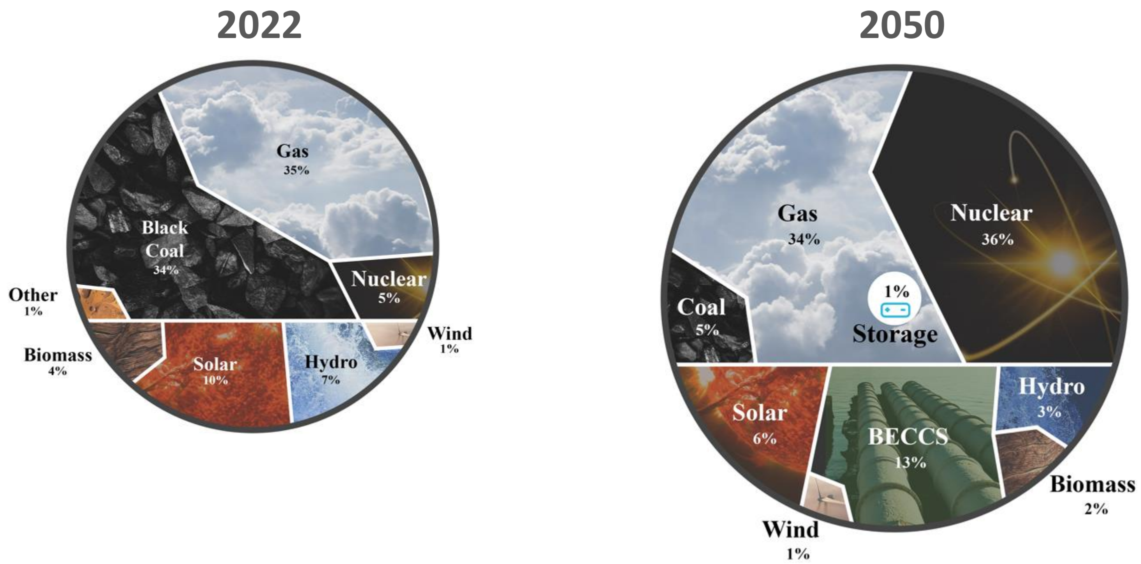
Australia – moving from a high emissions grid to net zero by 2050



This work has also examined the impact of a strong push to decarbonise the Australian NEM with just renewables, storage and a significant strengthening of interconnections. This was set to reach 90% decarbonisation by 2040 at the lowest system cost, subject to the constraint of being a renewables-only grid. This case study then supposed there was policy U-turn, allowing all technologies to be available for the final push to net zero by 2050. Even though the grid had been set up to be as renewables friendly as possible, it resulted in no additional renewables being built in the 2040's. Biomass combined carbon capture and storage was built, with some additional unabated gas. However, these U-turn scenarios could not achieve the lowest cost previously determined.

Focusing on Japan, nuclear plays a critical role in the net zero 2050 lowest cost scenarios. Biomass with carbon capture and storage, also enables a strong back up system of gas generation plant, being able to offset emissions to enable net zero. Japan, having a long tradition of energy diversity will also rely on coal (or maybe gas) based generation with carbon capture alongside its nuclear fleet. More work is required to examine the role of carbon capture and storage generation as an alternative to nuclear.

Japan – moving from a high emissions grid to net zero by 2050



This work, using the MEGS modelling tool, while focusing on lowest total system cost opportunities, show that all decarbonisation solutions are more expensive than today's grid. It also shows that while all technologies need to be available for decarbonisation, carbon capture and storage is central to the optimum solutions available. Without it, especially in conjunction with biomass to create negative emissions, it is very difficult to approach full decarbonisation at a reasonable cost.

Technical Summary

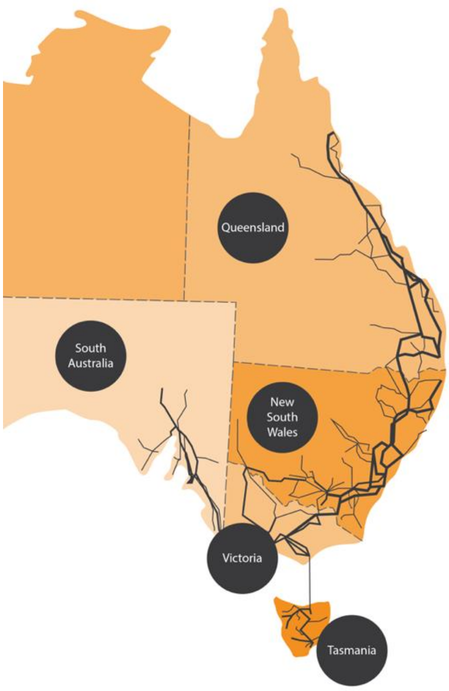
The global energy transition is proving to be harder than many people have previously imagined. The many conflicting international, national, regional, and local priorities are making planning for a net zero future very challenging. In addition, there are conflicting views on the roles particular technologies should play in the grid of the future. There are also independent studies, using different assumptions, and importantly focusing on different questions, that come up with seemingly conflicting views of the future.

In addition to the complexity, transitioning to net zero is not just the energy sector endeavour and realistically it will require nothing less than a complete and radical transformation of all processes that emit greenhouse gases. Even so, not all processes can reach zero emissions requiring compensation from negative emission technologies or processes. What this means for the electricity sector is complex.

This study looked to investigate the interdependencies of different power generation plants in a highly decarbonised future. The focus was to examine the role of fossil and biomass generation (with and without CCS) alongside other technologies important for a zero carbon future. Most importantly the aim was to find the lowest cost way to achieve net zero whilst maintaining grid security for three case studies.

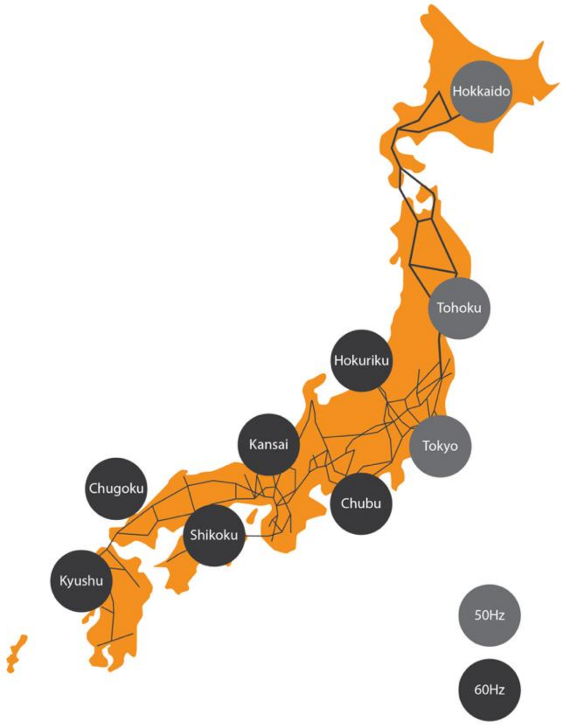
The three case studies were based on two different systems to represent the characteristics of a decarbonised 2050 power grid across a range of scenarios.

The first two were based on the Australian National Electricity Market (NEM) with its five Eastern interconnected states. Currently coal forms the backbone for the three largest states (Victoria, New South Wales and Queensland). South Australia has a mix of gas and renewable generation, and Tasmania is hydro dominated.



The first case study focused on finding the lowest cost way of decarbonising the grid by 2050 (given the cost assumptions) but with minimal constraints on technology availability. The second case study supposed there was a drive to decarbonise using renewables alone, until 2040. when a policy U-turn allowed any technology to be built from then on.

The third case study was based on the Japanese electricity grid which comprises two major interconnected systems: the Eastern Japan grid which runs at 50Hz and is divided into three regions. The frequency of the Western Japan grid is 60Hz and it is divided into six regions. These grids have unique characteristics and energy compositions, though nearly all regions are supported by a nuclear generation backbone.



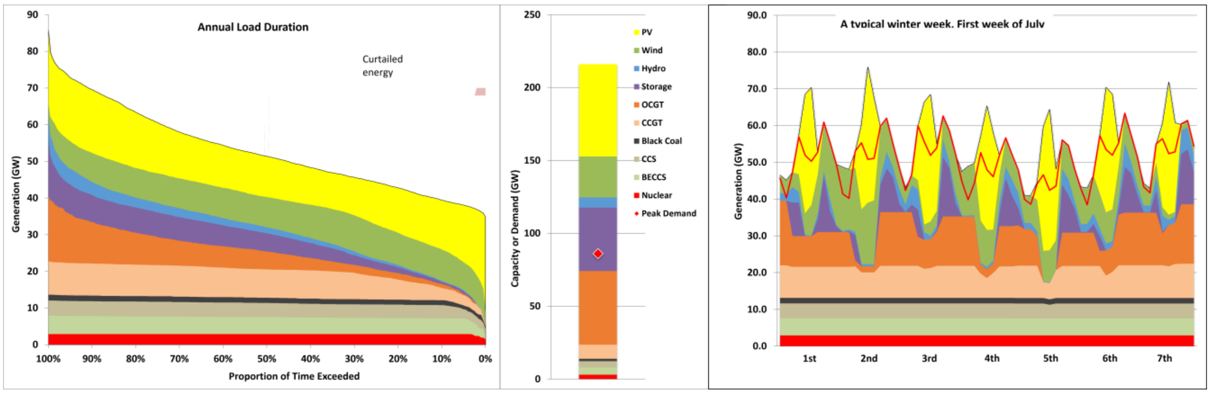
Importantly, transitioning to a decarbonised grid is more expensive than maintaining the current high carbon grid. Constraining some of the technology options that may be available for this radical transformation increases the overall decarbonisation costs, and in some circumstances, limits our ability to get to net zero at all.

The importance of modelling future decarbonised electricity grids has risen in recent years given the transformational change required to reduce emissions. Additionally, on the generation side, increased variable renewable generation requires modelling to consider elements such as additional transmission, backup supply for renewable droughts and grid stability. On the customer side, the increased electrification at the domestic, commercial, and heavy industrial level with new loads needs consideration.

Finding the generation mix with the lowest total system cost for deep levels of decarbonisation is critical for electricity consumers and taxpayers, who together need to cover the costs of the entire electricity system. A future system must maintain system security and “keep the lights on”. To ensure that the technical constraints of a secure and competent grid were met the modelling was based on MEGS. As well as meeting demand at each sequential time step, MEGS models grid services, such as firm capacity, inertia, and frequency response, ensuring that there are sufficient volumes of these balancing mechanisms available to the grid operator.

Using the MEGS model, this work, focusing on a lowest total system cost approach, demonstrated that there are viable scenarios for a net zero 2050 electricity grid.

The characteristics of a net zero electricity grid generation profile for the Australian east coast grid (known as the NEM) for 2050 were modelled. Examining the lowest total system cost generation solution, with its projected generation profile some interesting observations may be made.



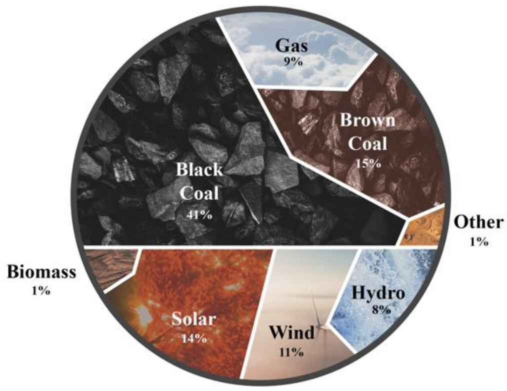
- The modelled system has a total capacity of over 200GW of installed capacity.
- Nearly half of the generation in this lowest total system cost scenario is from wind and solar PV, with solar PV providing the larger share.
- While there is some curtailed energy, it is very minimal, meaning the generation stack is utilised very efficiently.
- The remainder of the generated electricity is delivered equally by peaking, mid-merit, and firm-low emissions power plants.
- BECCS is an important low carbon generator, although only 10% of total energy, its negative emissions allows flexible gas to support renewables.
- The remainder of the low carbon generators are divided equally between CCS and nuclear.

This work has also examined the impact of a strong push to decarbonise the Australian NEM with just renewables, storage and a significant strengthening of interconnections. This was set to reach 90% decarbonisation by 2040 at the lowest system cost, subject to the constraint of renewables being the only low carbon technology. This case study then supposed there was policy U-turn, allowing all technologies to be available for the final push to net zero by 2050. Even though the grid had been set up to be as renewable friendly as possible, it resulted in no additional renewables being built in the 2040’s. Biomass combined carbon capture and storage was built, with some additional unabated gas. However, these U-turn scenarios could not achieve the lowest cost previously determined.

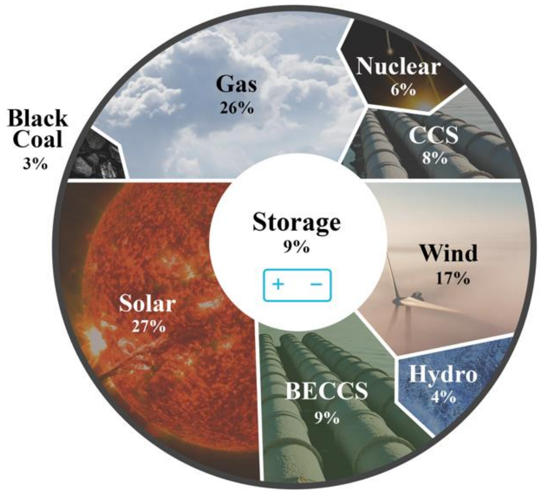
In summary renewables will play an important role, as will energy storage. Australia will move from a heavily coal (and gas) generation backbone to an electricity grid mainly based on renewables and gas underpinned by nuclear and fossil fuelled generation with carbon capture and storage. Biomass, in conjunction with carbon capture and storage facilitates a lowest cost grid, enabling gas-based backup systems. These gas generation plants ensure the grid can cope with long periods of low renewables – the Australian winter months.

Australia – moving from a high emissions grid to net zero by 2050

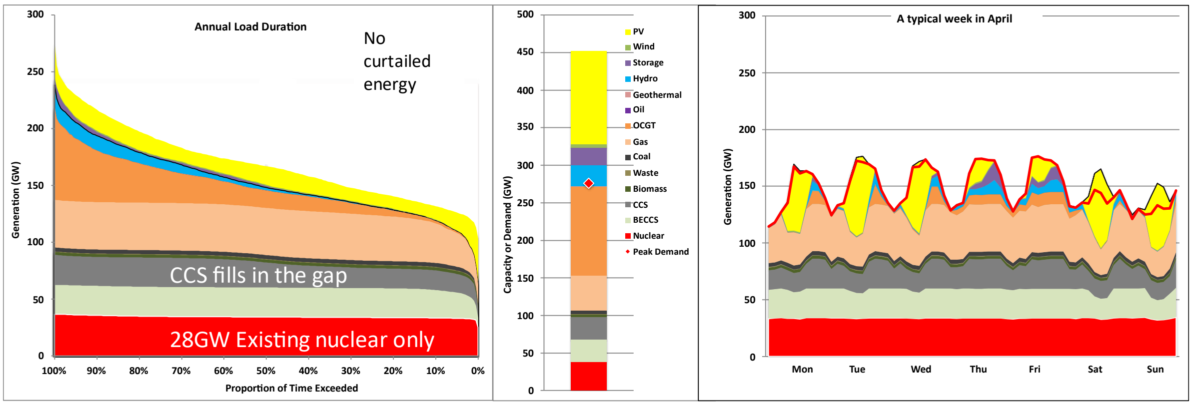
2022



2050

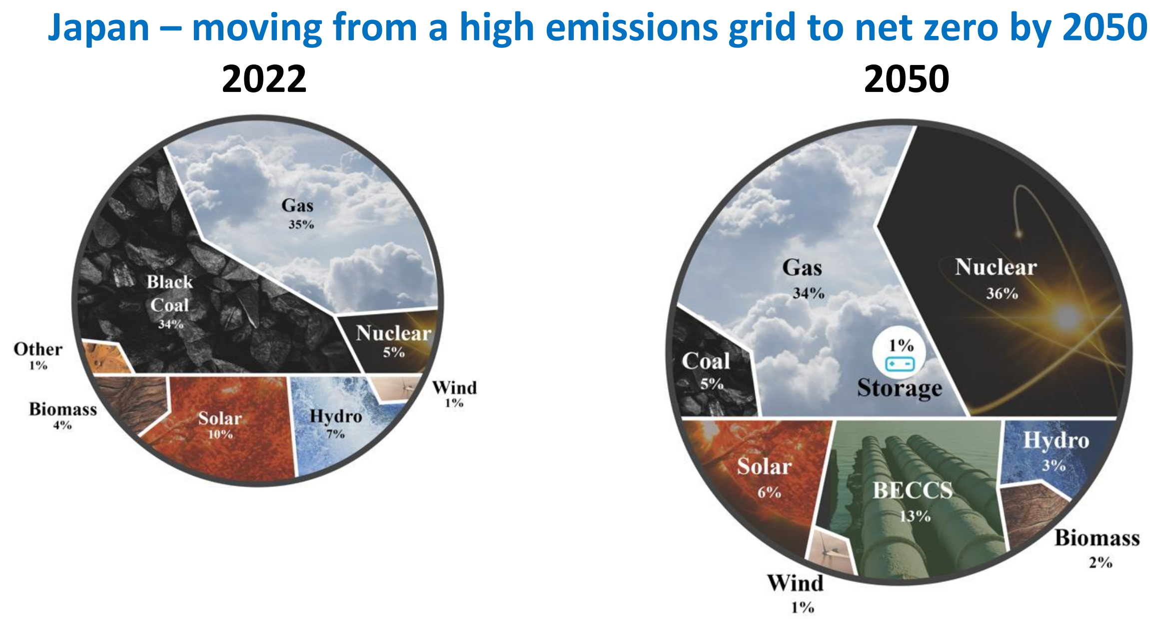


Japan has long realised the sensitivity of its energy supply and relies on diversification of generation technologies to manage risks. Within the context of a diverse generation portfolio, a scenario was examined where no new nuclear was to be constructed but allowed the current 28GW to be refurbished and brought back online. Within these constraints the characteristics of a net zero electricity grid generation profile for the Japanese grid for 2050 was modelled. Examining the lowest total system cost generation solution, with its projected generation profile, some interesting observations may be made.



- Without additional nuclear power, the generation capacity of a net zero 2050 would reach 450GW.
- The firm dispatchable, low emission technologies are BECCS and CCS. A combined total of around 100GW underpins the grid.
- Gas combined cycle plants also run as near baseload capacity, with open cycle gas operating as peaking plant.
- Renewables play a relatively minor role within the net zero system despite a large installed capacity of solar PV, in particular.
- Storage is charged with excess energy, however, the system has no curtailed energy, with an effective generation portfolio.
- BECCS plays a critical role within the net zero context, offsetting all the gas emissions. BECCS effectively offsets 294MT of CO_2.

In summary, nuclear plays a critical role for Japan in the net zero 2050 lowest cost scenarios. Biomass with carbon capture and storage, also enables a strong back up system of gas generation plant, being able to offset emissions to enable net zero. Japan, having a long tradition of energy diversity will also rely on coal (or maybe gas) based generation with carbon capture alongside its nuclear fleet. More work is required to examine the role of carbon capture and storage generation as an alternative to nuclear.



Further Work

A number of interesting questions remain around the following:

- The constraints, restrictions, costs, and other assumptions around biomass should be tested to understand their impact on future scenarios.
- The cost, practicality and efficiency of hydrogen, ammonia and other hydrogen storage options should be explored within the Japanese and Australian contexts.
- The constraints and costs of CCS for Japan, and the opportunities for storage, including export, need better characterisation.
- The cost and performance interplay between nuclear and CCS technologies needs exploring, including the role and importance of CCS flexibility.
- The constraints and costs for the development of renewables in Japan, needs better definition, particularly for both onshore and offshore wind.

Conclusion

This work, using the MEGS modelling tool, while focusing on lowest total system cost opportunities, show that all decarbonisation solutions are more expensive than today's grid. It also shows that while all technologies need to be available for decarbonisation, carbon capture and storage is central to the optimum solutions available. Without it, especially in conjunction with biomass to create negative emissions, it is very difficult to approach full decarbonisation at a reasonable cost.

Scope of Work

IEAGHG want to understand the interdependencies of generation plant in a highly decarbonised future. The focus is to look at the role of fossil and biomass generation (with and without CCS) alongside other technologies important for a zero carbon future.

Two systems were modelled to represent 2050, Australia and Japan, the former with two distinct cases studies to give three different grids as a basis for sensitivities. Firstly, the Australian National Electricity Market (NEM) with its five Eastern interconnected states. Currently coal forms the backbone for the three largest states (Victoria, New South Wales and Queensland). South Australia has a mix of gas and renewable generation, and Tasmania is hydro dominated.

The second system, the Japanese electricity grid comprises two major interconnected systems: the Eastern Japan grid runs at 50Hz and is divided into three regions. The frequency of the Western Japan grid is 60Hz and is divided into six regions. These grids have unique characteristics and energy compositions, though nearly all regions are supported by a nuclear generation backbone.

The programme of work consisted of the following tasks:

Literature Review

- This focussed on publications where care has been taken to ensure the system modelled delivers power without compromising the reliability standard and takes a technology neutral stance with the sole objective of decarbonisation.

Data collation

- A common set of assumptions was used to provide consistency. A local consultancy was used to help collate the data set for Japan.

Modelling Australian NEM, lowest TSC

- For this case study, it was assumed that the system will meet net zero at the lowest total system cost (TSC). A full range of technologies was made available including coal and gas with and without carbon capture and storage, nuclear, bioenergy carbon capture and storage, biomass, onshore wind, utility solar PV, rooftop solar PV, batteries, and pumped storage.

Modelling Australian NEM, Highly Renewable

- This case study explores a system that has been highly supportive of renewables, delivering 90% decarbonisation with wind and solar alone by 2040. Pumped storage, strong interconnection options and a large amount of battery capacity will have been delivered by 2040. Thereafter a technology neutral approach between 2040 and 2050 removes the last 10% of emissions and serves a growing demand at lowest possible cost.

Modelling Japan, lowest TSC

- For this case study, the underlying assumption was that the system will meet net zero, making use of its legacy nuclear plant, new nuclear as well as having all other options available (subject to land use constraints) to decarbonise at lowest total system cost.

Sensitivities

- This task sought to explore the sensitivity of the best solutions to the availability of some key technologies and fuel costs. The ability of MEGS, a tool for Modelling Energy and Grid Services, to generate a large database of scenarios allows sensitivity studies to be undertaken by filtering scenarios, for example by excluding all those that use a certain technology and looking in detail at how the least cost solution changes. Consideration was also given to exploring changes in gas price.

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Introduction

Most modern electricity grids around the world are now progressing along the decarbonisation journey to deliver reliable, affordable, and low carbon power to industrial, commercial, and residential users. This journey is being carried out within complex social, political, economic, and environmental constraints and demands.

The decarbonisation journey is also seeing a major change in the characteristics of national grids as they move from heavily centralised systems to ones with large amounts of decentralised generation, driven by the adoption of wind and solar PV, in particular. Energy storage is also changing the way in which future grids are being planned, ensuring that supplies remain adequate as fossil plant is replaced by variable input generation.

The case of low emissions dispatchable power generation technologies such as nuclear, biomass carbon capture, and fossil fuel-based carbon capture technologies needs more consideration in relation to future decarbonised systems. Considerations of changes in the mix of generation technologies must take total system costs into account.

To the consumer, be they residential, commercial, or industrial, the cost competitiveness of power is paramount. The "total system cost" is the closest metric we have that reflects the price paid by the consumer for the power they consume. Therefore, possible future grid combinations should be optimised to keep the total system cost as low as possible within the planning constraints that need to be applied. This least cost pathway for generation options, while keeping carbon emissions in check and the grid secure so it can supply at all times, should form the basis of all future scenarios.

This study seeks to demonstrate what opportunities the Australian and Japanese stakeholders have to achieve a net zero, lowest cost power system.

What is Net Zero

According to the United Nations 'Net Zero' is the reduction of anthropogenic greenhouse gas emissions emitted to the atmosphere to as close to zero as possible with any remaining emissions presumed to be re-absorbed from the atmosphere, by oceans, forests and other naturally occurring carbon dioxide sinks. [1]

> *'NET ZERO' is the ideal state where the greenhouse gases emitted to the atmosphere are balanced by the amount of greenhouses gases removed.*

The science indicates that to avert the worst impacts of climate change and preserve a liveable planet, global temperature increase needs to be limited to 1.5°C above pre-industrial levels. Currently, the earth is already about 1.1°C warmer than it was in the late 1800s, and emissions continue to rise. To keep global temperatures well below 2°C above pre-industrial times while pursuing means to limit the increase to 1.5°C as called for in the Paris Agreement, [2, 3] emissions need to be reduced by 45% by 2030 and reach net zero by 2050. [1] The Intergovernmental Panel on Climate Change (IPCC) have recently released their summary of the final (synthesis) report for the sixth cycle of assessments, which says it is now likely temperature will exceed 1.5°C. [4]

How Can Net Zero be Achieved?

The global energy transition is proving difficult, with many conflicting international, national, regional, and local interests within a global context of differing political and social priorities. [5-7] Transitioning to net zero is not just the energy sector endeavour, global emissions reductions is required from all sectors, and presents as one of the greatest challenges mankind has faced. Realistically it will require nothing less than a complete and radical transformation of our greenhouse gas emissions.

Greenhouse gas emissions from the generation of electricity and related indicators, including carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O) emissions from fossil fuel combustion and associated fugitive emissions [8] accounts for approximately three-quarters of greenhouse gas emissions today. [9] Their abatement is critical to averting the worst effects of climate change. [1, 10]

Replacing unabated coal, gas and oil-fired power with electricity generation from low emissions sources, such as nuclear power plants [11-13] and fossil fuel equipped carbon capture plants [14-18] and renewable plants (such as wind, solar, hydro and geothermal) [19-21], would radically transform global carbon emissions. [22]

A Total Systems Cost Approach to Grid Modelling

The importance of modelling the electricity grid has risen in recent years given the drive for transformation change required to reduce emissions. [23] Additionally, on the generation side, increased variable renewable generation requires modelling to consider elements such as additional transmission, back supply for renewable droughts and grid stability. On the customer side, the increased electrification at the domestic, commercial, and heavy industrial level with new loads needs consideration. This in addition to the complexities of self-generation, energy storage and an increased level of engagement with the system as a 'prosumer' and provider of flexibility services.

Importance of a Total Systems Cost Approach

A systems modelling assessment methodology recognises the pre-existence of a functioning monolith grid. Its output reports on the economic value of adding a new power generation asset to this grid. This is important because while the modelling is faithful to engineering constraints and market operating rules, it remains free from policy intentions. Therefore, it is a transparent system cost minimisation exercise. Policy and regulation intent can always be interrogated as a specific case study. [24]

Power system models are critical tools that policy makers and other stakeholders utilise to develop and test the possible future scenarios implications. It is important therefore that such models are adequately equipped to ensure that the requirement for the most critical grid services are as central to their algorithm as is balancing of energy – which has historically been the most important requirement. [24]

For too long, simplistic technology-based cost metrics like Levelised Cost of Energy (LCOE) [25-28] remains the staple of energy technology comparisons. LCOE has been widely used to compare the economic merits of different generating technologies, [29] some even offering web tools for its evaluation. [30] However, such energy-only metrics, which do not consider the whole system, say nothing about the value of a technology being added to the system, especially ones that deliver grid services alongside, or rather than, energy. [27, 31-35] This can result in key decision makers using misleading information, which may lead to the dismissal of valuable technologies critical to a future system, because they are judged solely on their ability to deliver energy, rather than lower total system cost within a complex electricity system. [24]

For too long, simplistic technology-based cost metrics like LCOE have dominated the discussions on technology selections for future grids.

Increasingly though, many now criticise LCOE as a relevant metric for designing a low-cost system [25, 27, 28, 36-38], including International Renewable Energy Agency (IRENA), which produces an annual report of renewable LCOE's that says "it is not a substitute for electricity system simulations that can determine the long-run mix of new capacity that is optimal in minimising overall system costs, while meeting overall demand, minute-by-minute, over the year." [39]

Different metrics have been proposed to augment LCOE:

- Levelised Avoided Cost of Electricity (LACE) favoured by the US EIA. [36, 40]
- Enhanced LCOE as used by UK's Dept for Business Energy and Industrial Strategy. [41]
- System LCOE proposed by Falko Ueckerdt *et al* [42] and used in Japan. [43]
- Value-Adjusted LCOE (VALCOE) first proposed by IEA. [44]

Selected metrics have been compared by [36, 45] but most are based on LCOE, so retain the worst of its features. However, by retaining a levelised cost approach the shortcomings remain. Only by looking at Total System Cost (TSC) is it possible to understand the total cost to consumer. [45, 46] There are only a few within the modelling communities that are focusing on total system cost and delivering a decarbonised system that minimises cost to consumer.

These include:

- Balcombe *et al*. [47] looked at cost to consumer associated with micro combined heat and power, solar PV and battery integration for 30 different households but only at a household level, and using old demand data from 1990.
- Strbac *et al* [48, 49] examined a whole system costs approach.
- EMMA by Hirth at Neon, models both dispatch of and investment in power plants, minimizing total costs with respect to investment, production and trade decisions subject to a large set of technical constraints. [50]
- The Centre for Environmental Policy at Imperial has consistently focussed on modelling the effect of different technology mixes on TSC, using their ESO model and its derivatives. [51, 52]
- Lappeenranta University of Technology use the LUT Energy System Transition Model [53, 54] which has hourly timesteps and optimises system cost.
- Boston and Thomas at the Energy Research Partnership [28] developed the BERIC model, a precursor to MEGS: Modelling Energy and Grid Services. [24]
- Boston and Bongers [24] MEGS: Modelling Energy and Grid Services, a total systems cost approach.

Total systems cost is the most appropriate metric in a power grid for stakeholders who need to plan for, and understand the effect on, those paying for the energy system, either directly by the consumer through bills or indirectly by the taxpayer through subsidy. A policy maker or long-term system planner may be concerned for example by the affordability of changes, rather than investors' returns. However, the latter is also important to consider, as investment may not occur if returns are below expectations, though investments can be incentivised by policy changes, regulation, market mechanisms and cross- subsidies [45]. However, a suboptimal technology mix, once installed, cannot be so easily addressed once built into the system [55]. Hence the minimisation of total system cost, subject to meeting appropriate grid security and environmental standards, should be the primary concern in both the short and long-term planning horizons.

Total systems cost is the most appropriate metric in a power grid for those stakeholders who pay for the energy system.

A conceptual representation of TSC is provided in Figure 1. [45, 56] Electricity system assets are shown within the system circle in the diagram and refer to physical parts of the system, such as generators and grid facilities. Costs refer to any payments that leave the electricity system, such as OPEX shown by blue arrows, or taxes shown by green arrows. However, these costs exclude exchanges between participants of the system, such as a generator's grid connection fees or the system operator's payments for grid services shown by light blue arrows. The price paid by consumers, either directly or indirectly, (orange arrows) must cover all these outgoings and hence is also, in the example represented in Figure 1, equal to TSC.

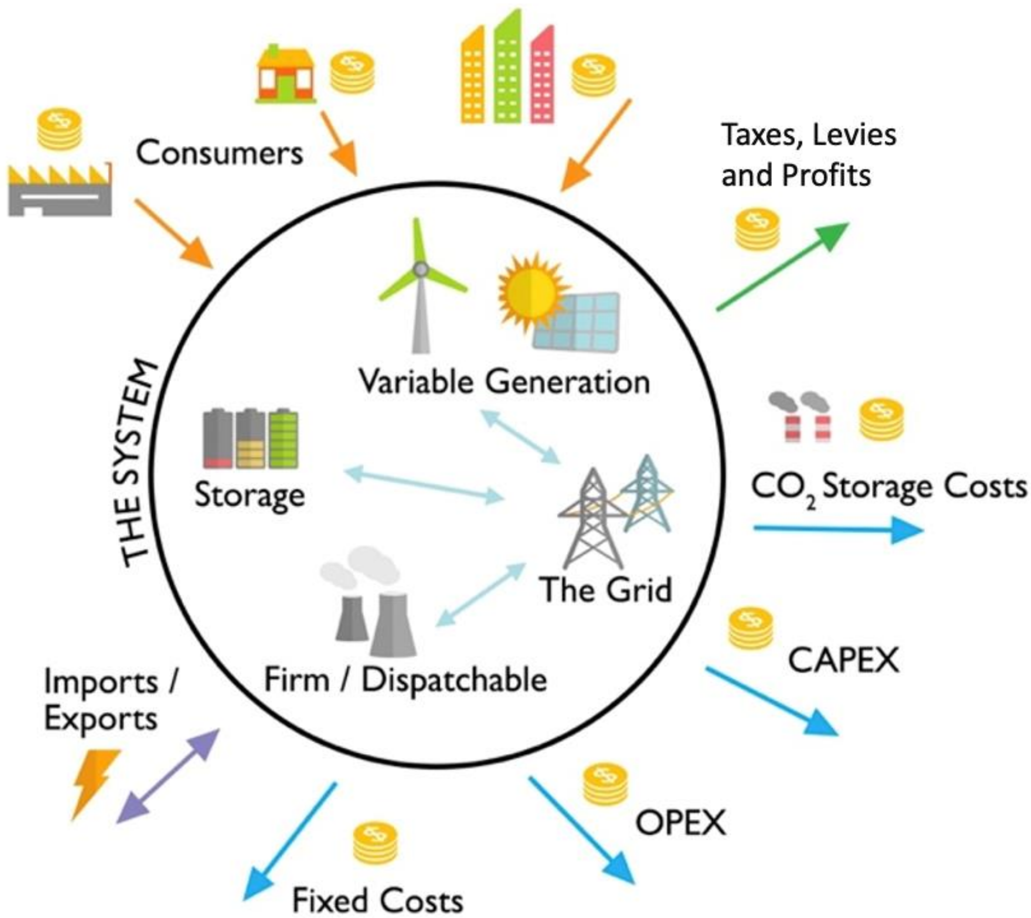


Figure 1: Derivation of Total System Cost as a function of external financial exchange

Power Grid Modelling Approaches

There are many modelling tools with varying degrees of detail and scope. The authors of a PyPSA paper produced a useful comparison of the most prominent in 2018 [23], which has been updated for version numbers, is reproduced in Table 1.

Table 1: Model comparison taken from Brown et al's PyPSA paper [23] (updated)

				Grid Analysis			Economic Analysis							
	Software	Version	Free Software	Power Flow	Continuation Power Flow	Dynamic Analysis	Transport Model	Linear OPF	SCLOPF	Nonlinear OPF	Multi-Period Optimisation	Unit Commitment	Investment Optimisation	Other Energy Sectors
Power System Tools	MATPOWER	7.1	√	√	√		√	√		√				
	NEPLAN	10.9.1		√		√	√	√	√	√				√
	pandapower	1.4.3	√	√			√	√		√				
	PowerFactory	2023		√		√		√	√	√				
	PowerWorld	23		√		√	√	√	√	√				
	PSAT	23.0	√	√	√	√		√		√	√	√		
	PSS/E	35.4		√		√		√	√	√				
	PSS/SINCAL	20.0		√		√				√				√
	PYPOWER	5.1.16	√	√			√	√		√				
	PyPSA	0.25.2	√	√			√	√	√		√	√	√	√
Energy System Tools	calliope	0.6.10	√				√				√		√	√
	Minpower	5.0.1	√				√	√			√	√		
	oemof	0.5.0a5	√				√				√	√	√	√
	OSeMOSYS	1.0.1	√				√				√		√	√
	PLEXOS	9					√	√	√		√	√	√	√
	PowerGAMA	1.1.3	√				√	√			√			
	PRIMES	2018					√	√			√	√	√	√
	TIMES	4.7.6	√				√	√			√	√	√	√
	urbs	1.0.1	√				√				√	√	√	√

There are other models, not in Table 1, with a particular focus on TSC and its minimisation:

- BERIC, [28] 2015, by Energy Research Partnership. Written by one of this review's authors, very similar to MEGS, but relatively primitive now compared to MEGS.
- EMMA, [50] 2017, by Lion Hirth working for Neon at the time. "EMMA minimizes total system cost, i.e. the sum of capital costs, fuel and CO_2 costs, and other fixed and variable costs of generation, transmission, and storage assets. Investment and generation are jointly optimized for one representative year. Decision variables comprise the hourly production of each generation technology including storage, hourly electricity trade between regions, and annualized investment and disinvestment in each technology, including wind and solar power. The important constraints relate to energy balance, capacity limitations, and the provision of district heat and ancillary services." EMMA is calibrated for NE Europe from France to the Nordics.
- ESO was developed at Imperial by Heuberger with help from one of this review's authors. It is based on 11 standard days so cannot evaluate storage but is also focussed on TSC and consistently comes out with similar results to MEGS. [51] It has been used in previous work for IEAGHG and has been extended to include an explicit description of all the ancillary services supporting frequency, voltage, system restart and reserve. [35]
- WeSim by Pudjianto *et al* at Imperial College, [57] although this model is focussed on evaluation of storage in particular.

Finding the generation mix with the lowest total system cost for deep levels of decarbonisation is critical for electricity consumers and taxpayers, who together need to cover the costs of the entire electricity system. MEGS is an electricity system scenario tool designed to explore options to approach the optimal mix for a particular decarbonisation target. Figure 2 shows that it sits between high level whole system energy models such as TIMES [58] on the left and detailed electrical modelling such as DigSilent Power Factory [59] or Siemens PSS/E [60] on the right.

A future system must also maintain system security and "keep the lights on". To ensure this, MEGS also models grid services, such as firm capacity, inertia, and frequency response, ensuring that there are sufficient volumes of these balancing mechanisms available to the grid operator. MEGS has been validated against generation data for the Australian National Electricity Market (NEM) and has been used to explore the lowest cost frontier at high levels of decarbonisation. [24, 38]

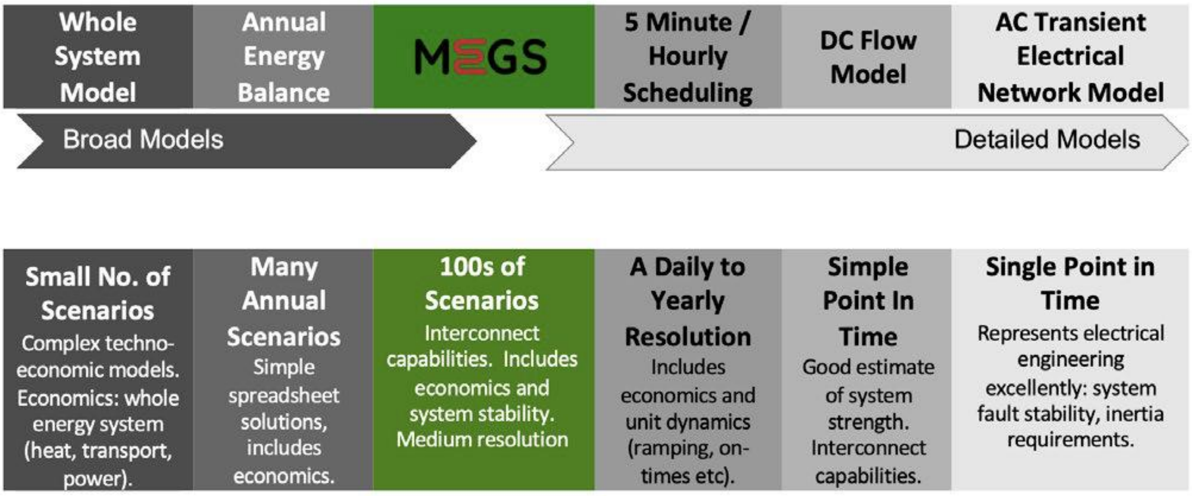


Figure 2: MEGS model comparison to other methodologies

MEGS: Modelling Energy & Grid Services

MEGS – Modelling Energy and Grid Services, is a regional electricity system model that ensures there is sufficient firm capacity to meet demand, and that the grid operator has sufficient services to maintain grid supply and stability. [24]

MEGS departs from more traditional modelling as it captures the requirement and supply of grid services beyond the need to match generation with demand (net of imports). This need has come about because in a grid that is transitioning towards low emission renewables (especially wind and solar PV), there is increasing requirement on system operators to have access to frequency response, reserve and inertia services, and other grid services. [61] The conventional sources of these services are being lost as fossil-fuelled power generation is being displaced from the system.

Due to high levels of synchronous generation on the grid, historically the cost of these has been small and mostly neglected, and some services, like inertia, have been supplied for free. [62] However, the perceived lack of importance of such services is no longer the case, as weather-dependent renewables have the potential to both increase demand for and reduce supply of these services.

The outcomes of the MEGS model seek to challenge current paradigms for understanding the TSC for electricity supply. Conventional modelling approaches make simple comparisons, which are made using traditional metrics like Levelised Cost of Energy (LCOE), do not consider the grid system requirements. [45] This modelling safeguards the resilience of a grid by enforcing a minimum level of inertia and seeks to ensure that the operator has sufficient frequency response and reserve services to maintain a stable grid.

The constraints at the core of MEGS are illustrated in Figure 3 to the left of the red brace, with the objective function displayed on the right. MEGS linearises all model variables, which allows it to use a highly efficient linear programming algorithm to find the optimum.

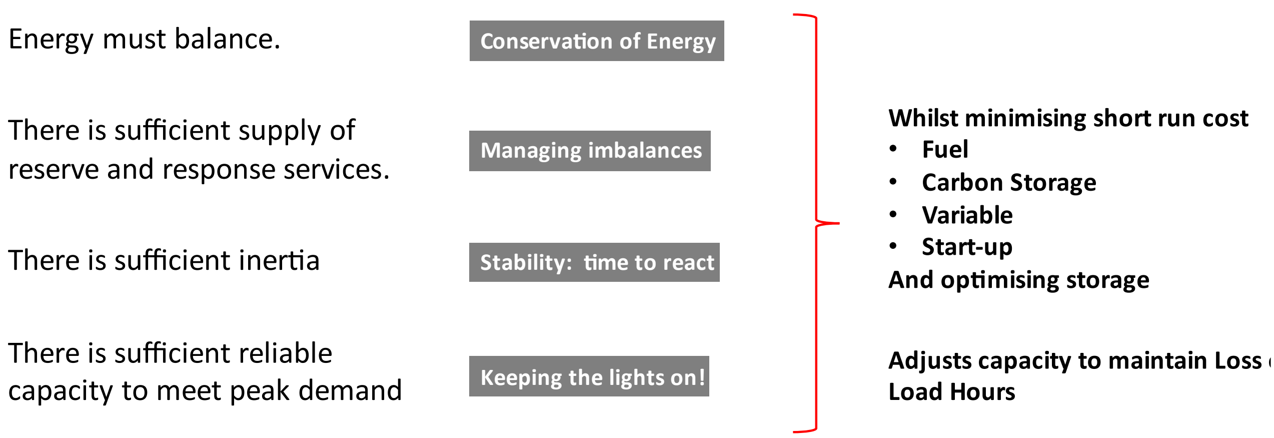


Figure 3: Definition of the constraints in MEGS

To ensure adequate grid services constraints are met, MEGS accounts for inertia both as a proxy for grid strength and for its damping effect on Rate of Change of Frequency (RoCoF), refer to the shading in Figure 4. [38, 63] MEGS also ensures that there is sufficient upwards frequency response and fast reserve for all timescales of less than 5 minutes.

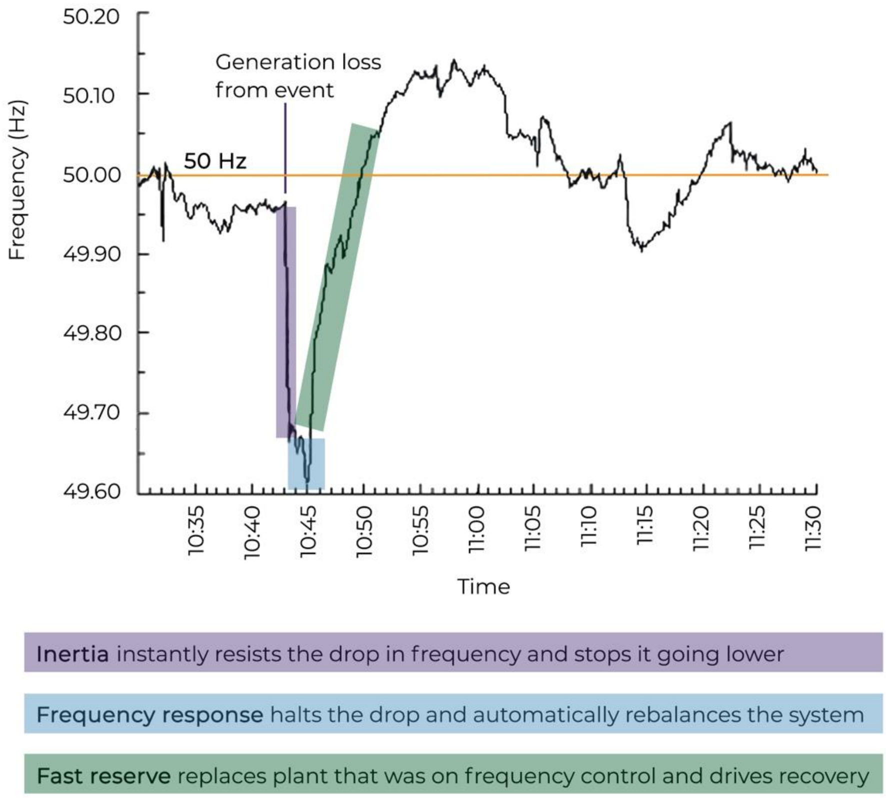


Figure 4: How Inertia, frequency response and reserve work together

Australian Modelling and Scenarios

Grid Background

The Australian NEM stands as one of the world's longest interconnected electricity systems, spanning across Queensland, New South Wales, Victoria, South Australia, and Tasmania (as shown in Figure 5). It operates under an energy-only market framework, emphasizing efficient energy generation and distribution. [64] The NEM began in 1998, integrating North Queensland with South Australia, connecting all the other states in between. Tasmania was added to the NEM in 2005 via a 370 km Basslink direct current undersea cable. [65]

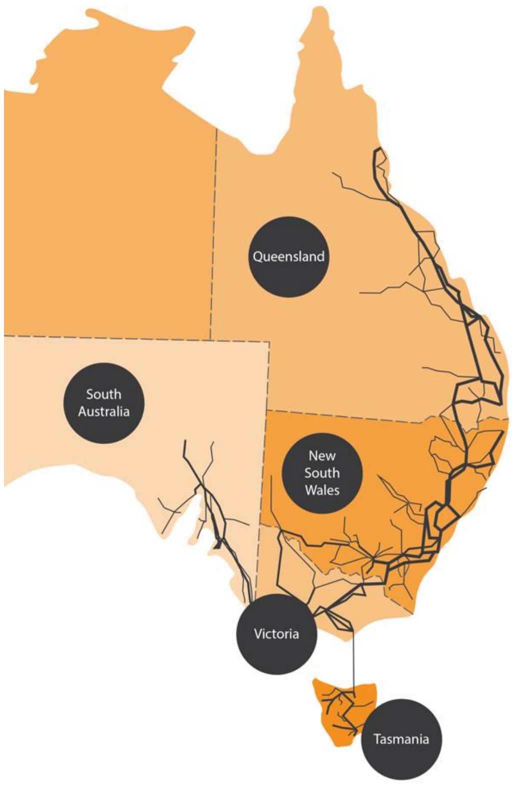


Figure 5: The Australian East Coast electricity grid (NEM)

In terms of energy composition, the NEM relies on a diverse range of sources to meet its electricity demands. As of the most recent data available, approximately 64% of its energy generation is derived from coal, emphasizing its role as a stable energy source. [66] Furthermore, renewables contribute significantly, accounting for 31% of the energy mix, showcasing a commitment to sustainability. Gas makes up the remaining 4%.

Scenarios & Assumptions Summary

MEGS models regions with interconnectors that can carry both energy and reserve services. When MEGS is configured for the whole Australian NEM, it treats it as an 'islanded' grid that consists of five state grids with relatively weak interconnections. The constraints (detailed in Figure 3) are applied in each of the five regions, with interconnectors allowing transfer of energy or reserve services to fulfil those needs. The relative weakness of the interconnectors means that inertia (which is also a proxy for local system strength and fault levels) cannot be transferred state to state. Likewise, it is assumed that each state will need to be able to cover its own demand with sufficient firm generation and storage capacity. Therefore, the minimum requirements for these must be met from within each state.

Lowest Cost Solutions for the Australian NEM – 2050

The transformation of the Australian east coast electricity grid, the NEM, from its current unabated coal backbone into a net zero or beyond generation profile will take a profound change. It is likely the generation mix will change significantly to be based mainly on low carbon technologies, from which several options were chosen for investigation. These were fossil with carbon capture and storage (CCS), nuclear, biomass energy with CCS (BECCS), onshore wind, PV, batteries, pumped storage and hydrogen storage. To ensure sufficient capacity to meet demand, at all times, open cycle gas turbines (OCGT) were added to meet minimum levels.

As an aside, it is noted that each of these technologies has its detractors and significant issues with deployment. CCS is untried at scale, nuclear is disallowed in Australia, biomass resource is limited, renewables suffer from wind and solar droughts and require significant support, batteries are only for short term storage, hydrogen is difficult to handle and untested and pumped storage is limited by geography. To meet net zero it is implausible that all these technologies fail to deliver, and some may deliver in part, so all were screened and fossil CSS, BECCS, nuclear, wind, PV and batteries were taken forward to be modelled in MEGS. The remaining long term storage options were included as part of a high renewables case study described later.

Using the MEGS model with the six different generation technologies, more than 700 possible future NEM's were explored, comprising every combination of three capacity levels for the six technologies and a balancing capacity of OCGTs in each region. This can determine the lowest cost decarbonisation frontier from a low base of only 30% proportional decarbonisation (with minimal deployment of any low carbon technology), to nearly 120% decarbonisation, with maximum deployment of technologies including the negative emissions achieved by BECCS. The results of this work are provided in Figure 6. Consistent with prior work, the total system cost of the transition ALWAYS increases with the level of decarbonisation. [19, 24, 38, 67]

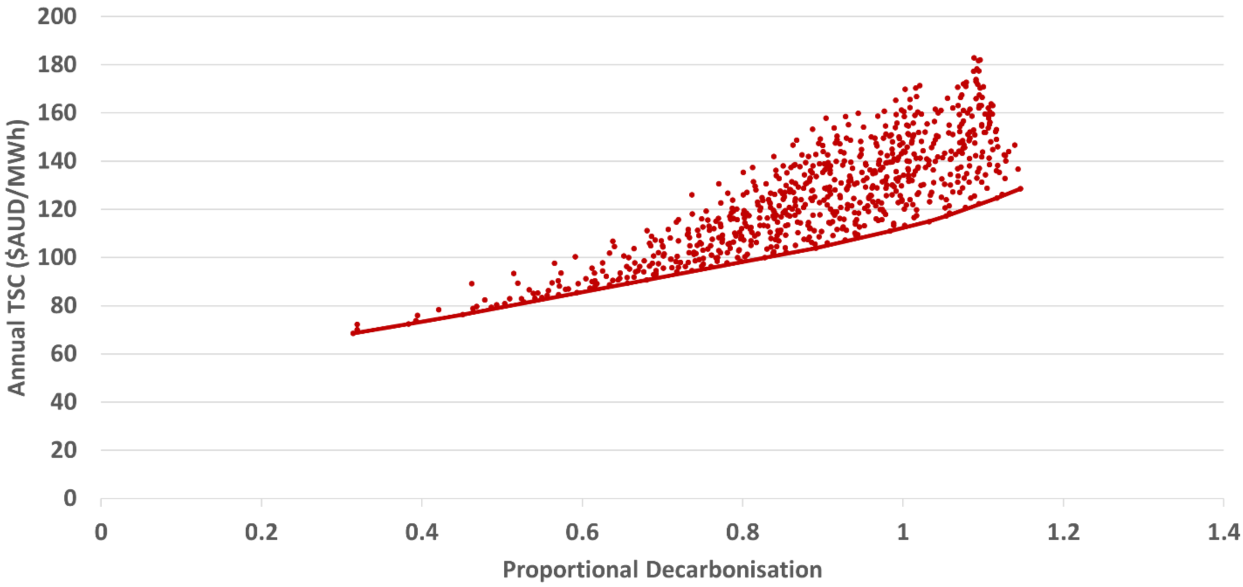


Figure 6: The NEM with 729 possible 2050 futures – targeting the lowest cost frontier

The scatter methodology employed gives an important view of the possible future decarbonisation opportunities. From this, a simple calculation to determine the cost of decarbonisation in terms of the cost of abated CO_2 can be carried out. For example, if a system has achieved net zero at the lowest cost, it lies on the lowest cost frontier shown in Figure 6 where it crosses decarbonisation at 1. Moving to higher or lower levels of decarbonisation at least cost will take the system along the lowest cost frontier line, the slope of which determines the change in cost. Given that the decarbonisation (x-axis) could also be expressed in tonnes of CO_2 abated the slope is directly related to the effective cost of carbon abatement. At this point (net zero), a system with the lowest total system cost would experience a cost of abatement of $AUD 475/tonne.

Decarbonisation will increase the cost of electricity – every scenario is more expensive than today – our aim is to minimise this cost!

The Impact of Constraining Carbon Capture Technologies on the Lowest TSC on the NEM

While the implied cost of carbon to decarbonise the Australian East Coast NEM is insightful, understanding the implications of constraints within a future system is an important element of understanding what building blocks may be used. By excluding some technologies, different total system cost frontiers emerge.

Figure 7 demonstrates the impact of constraining or not pursuing BECCS, coal or gas CCS technologies. Without coal or gas-based CCS, it remains possible to surpass the net zero target, with only a slight increase in the overall total system cost. With no coal or gas CCS, the lowest total system cost at full decarbonisation increases by $AUD 6/MWh. But the costs quickly increase as we go deeper into decarbonisation levels.

The importance of BECCS is also clearly demonstrated in Figure 7, with the BECCS cost frontier beginning to diverge from the lowest total system cost frontier at relatively low decarbonisation levels. From the 0.7 proportional decarbonisation point, removing BECCS as an option clearly becomes more expensive, however, the most significant impact is the inability for the system to achieve more than 0.95 proportional decarbonisation. Even then, it costs approximately $60 AUD/MWh more than the lowest cost frontier at the same decarbonisation level.

BECCS is the only carbon negative generation technology, its unavailability due to physical storage or biomass supply constraints, or policy makes a significant impact on the possible solutions and the depth of decarbonisation that is possible.

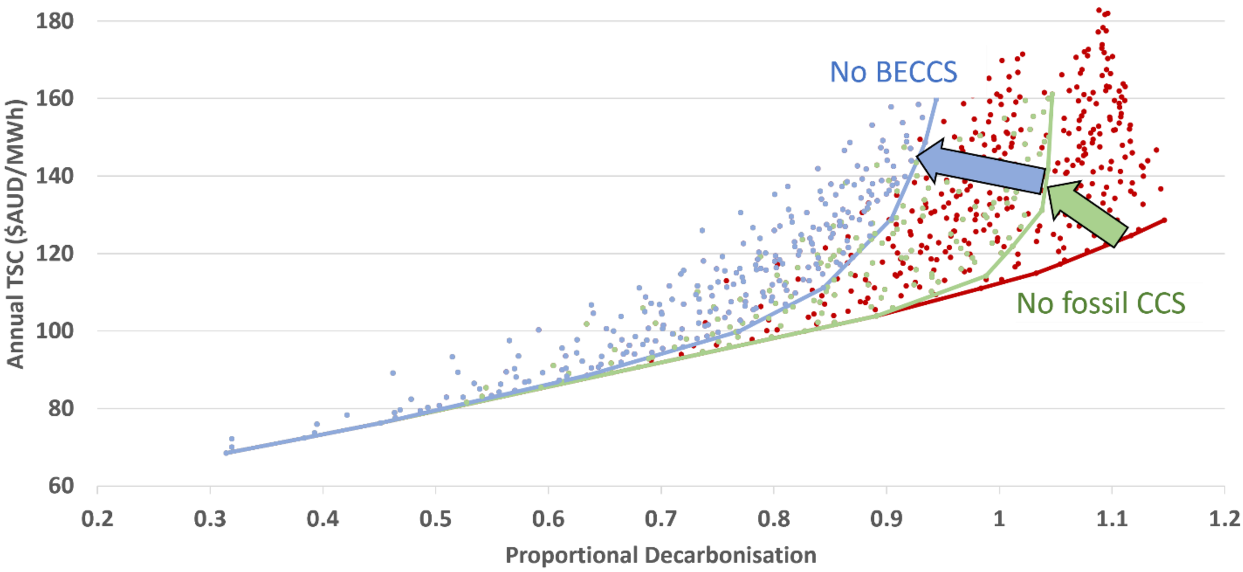


Figure 7: The NEM with 729 possible 2050 futures – impact of constraining CCS

The Characteristics of a 2050 Lowest TSC NEM Generation Stack

The characteristics of a generation profile for a net zero electricity grid in 2050, at the lowest TSC, was also determined. The 2050 projected generation profile is given in Figure 8, with a total capacity of over 200GW of installed capacity. Nearly half of the generation in this scenario is from wind and solar PV, with solar PV providing the larger share. While there is some curtailed energy, it is very minimal, meaning the generation stack is utilised very efficiently. The remainder of the generated electricity is delivered equally by peaking, mid-merit, and firm-low emissions power plants.

BECCS is an important low carbon generator, at nearly 30% of the low carbon generator stack. The remainder of the low carbon generators are divided equally between CCS and nuclear. The role of BECCS is critical to the lowest cost net zero solution, facilitating the use of unabated, relatively low-cost gas and coal plants. These mid-merit plants ensure that the system can deal with periods of low renewable power contributions. These periods of low renewable input are periods of serious stresses on generation systems. [67, 68] As shown in Figure 8, gas has the largest capacity, however, it has a relatively low capacity factor (21%), providing significant flexibility to the system. It is interesting to note that Net Zero Australia, an independent wide ranging study of pathways to net zero, has a similar important role for unabated gas and battery storage in each of its 5 core scenarios in support of a significantly developed renewables portfolio as seen here. [69]

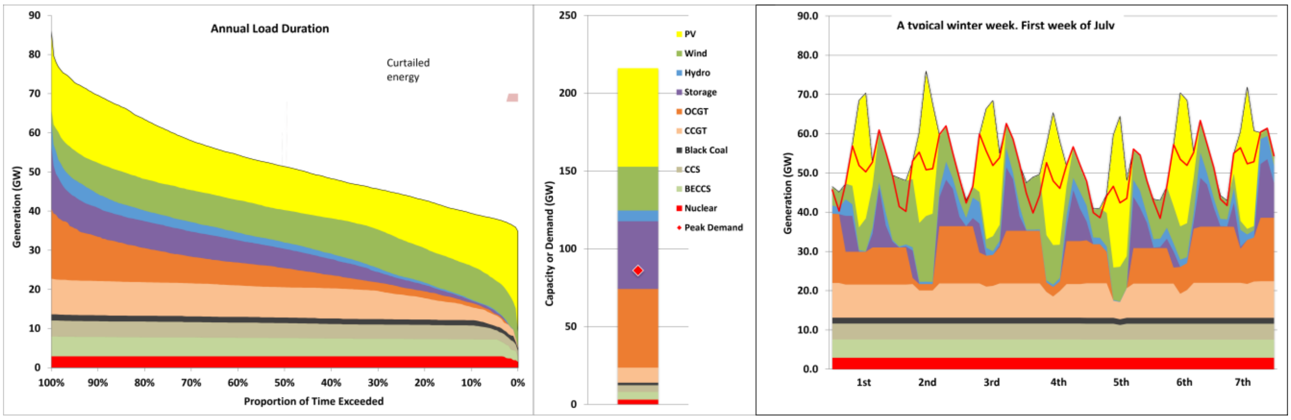


Figure 8: The lowest total system cost configuration for net zero 2050

The typical winter weather week shown in Figure 8 also shows the important role of energy storage. Excess solar is soaked up by the energy storage systems during the day, and excess wind stored during the nights. The storage systems dispatch during the evening peak, essential in a daily cycle routine. Frequent cycling of storage can make it relatively cost effective, reducing the TSC by reducing the need for excess renewable capacity. However, consistent with prior work, [68] the energy storage systems modelled here do not operate as significant long term storage options. Batteries and even pumped hydro are too expensive as seasonal stores or to act as standby for a period of low renewable input (renewables drought). In these seasonal storage modes, they may only be used once or twice a year (or maybe even not at all) but will require large volumes of energy to be released in a short time when actually called upon. Such storage requirements are better met by fuels coupled with cheap generation plant. Storing enough gas in a cavern or converted gas field to generate 10 TWh of electricity [70] (a typical requirement to cover a winter wind drought) is orders of magnitude cheaper than building sufficient batteries (50,000 x Hornsdale Power Reserves [71]), or pumped storage (30 x Snowy 2.0 [70, 72]) which are totally infeasible.

The Role of Gas Generation in the Lowest TSC 2050 NEM Scenario

This role of gas and its BECCS offset is explored in Figure 9. The majority of the gas contribution is during the Australian winter months. From around June through to September, gas contributes a significant amount of generation, with the combined cycles operating as near 'base load' for June and July. For the remainder of the year the gas plants operate as key peaking only generation assets typically making one start each day. These unabated gas emissions are offset across the year by BECCS.

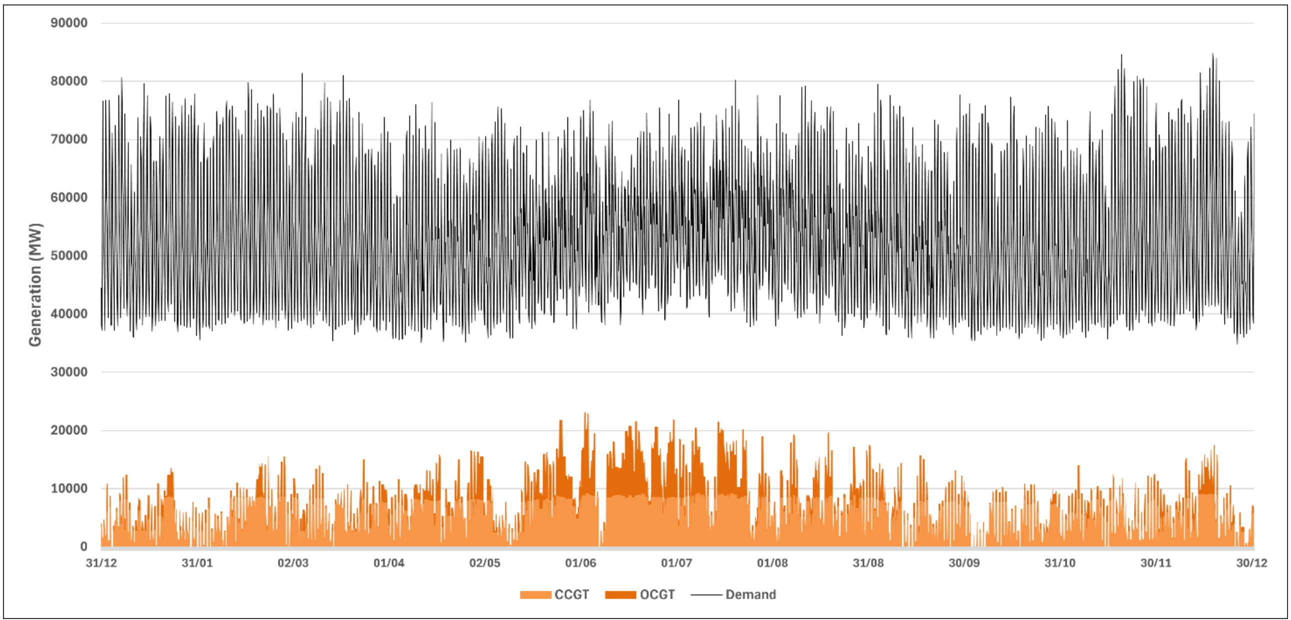


Figure 9: The role of gas in the lowest cost, net zero 2050 portfolio

If there is little to no option for sustainable biomass as a fuel for the BECCS / Gas generator synergy – flexible coal or gas CCS would likely be the replacement option. However, as shown in Figure 7, some BECCS is required to offset the unabated emissions, otherwise the system cannot achieve net zero and is significantly more expensive.

The Role of Unabated Gas or Coal in a Lowest TSC NEM Scenario

Modern electricity grids have been in a transition to decarbonise for some time, with wind and solar electricity generation being the primary technologies called upon to decrease emissions. [73] This increase in variable renewable generation has typically resulted in a reduction in coal and gas-based generators, which has led to grid operability issues. [74, 75] The need for flexible demand and generation assets on a modern, highly renewable grid needs to be managed. To continuously achieve the instantaneous balancing of supply and demand, the power system needs a diverse mix of centralised generation and distributed energy resources, demand response opportunities and network capacity. [76, 77]

This is not a new problem, with the Electric Power Research Institute (EPRI) publishing a report in 2013 on the required changes to the base loaded coal fleet to be flexible in a changing grid. [78] The National Renewable Energy Laboratory (NREL) have examined the evolution of baseload to peaking plants with a report in 2013, [79] concluding that coal plants can become flexible resources. This flexibility—namely the ability to cycle on and off and run at lower output (below 40% of capacity)—requires limited hardware modifications but extensive modifications to operational practice. Cycling does damage the plant and may impact its life expectancy compared to baseload operations. Nevertheless, strategic modifications, proactive inspections, and training programmes, among other operational changes to accommodate cycling, can minimize the extent of damage and optimise the cost of maintenance.

As shown earlier (Figure 9) gas peaking plant plays an important role within a highly renewable grid but many of the services it offers could be supplied by different technology, as such refurbished existing assets. These might not be flexible enough to replace all gas turbines but can certainly play a role in displacing a significant proportion. Hence, the comparison of these options is an important question to answer. Table 2 shows a cost comparison for building new open cycle gas plant compared with refurbishing existing coal assets. (Although we have earlier noted that LCOE is a poor metric for comparing different technologies, [45] if they are providing similar services it can be a useful indicator). The levelised cost for flexible refurbished coal was calculated first, and the levelised cost of new open cycle gas plant was calculated second to match the coal cost. This was done by varying the gas fuel cost. If coal is $AUD 2.10/GJ and gas is $AUD 16.10/GJ the two technologies are equal. If gas could be procured at lower prices, open cycle gas would be a cheaper option.

Table 2: New flexible open cycle gas compared with refurbished flexible coal in Queensland

	New Open Cycle	**Refurbished Coal**
CAPEX ($AUD/kW)	897	452
Fixed cost ($AUD/kW/Y)	10.2	53.2
Variable OPEX ($AUD/MWh)	7.3	4.5
Efficiency (HHV%)[1]	33	35
Fuel Cost ($AUD/$GJ_{HHV}$) ($AUD/Tonne)	**16.10**	2.10 62
LCOE ($AUD/MWh)	**595**	**595**

[1] Although gas power plant efficiencies are more often quoted on an LHV basis, fuel prices are usually quoted in HHV. For this report all efficiencies and fuel prices are on an HHV basis making comparison simpler. For gas plant HHV efficiency should be multiplied by 1.11 to derive LHV efficiency.

The Role of Gas or Coal CCS in a Lowest TSC NEM Scenario

In addition to peaking plant, flexible dispatchable low emissions plants are also important elements of a modern grid. Previous work commissioned by the International Energy Agency Greenhouse Gas (IEA GHG) in valuing flexibility in CCS [80] is a demonstration of its importance. So too the USA Department of Energy's FLExible Carbon Capture and Storage (FLECCS) program, [81] seeking to develop flexible CCS. This work includes both retrofits to existing power generators and greenfield systems. It assumed that plant with CCS was as flexible as unabated plant although running costs and start-up costs were significantly higher.

While this work did allow some flexibility of the CCS fleet, it did not seek to differentiate between gas or coal capabilities, therefore given the current status of the technology, CCS is not considered particularly flexible. [82] Table 3 shows the same type of cost comparison given for unabated gas and coal. The levelised cost for new build supercritical coal was calculated first, and the levelised cost of the new build combined cycle gas CCS plant was calculated second to match the coal cost. This was done by varying the gas fuel cost. If coal is $AUD 2.10/GJ and gas is $AUD 17.70/GJ the two CCS technologies are equal in cost. If gas could be procured at lower prices, gas would be a cheaper option, else coal would be the preferred option. Given the input assumptions agreed for use in this study, if new CCS power generation plant is to be built in Australia, then it would be coal-based.

Table 3: New gas and coal-based CCS cost comparison

	Combined Cycle CCS	**Supercritical Coal CCS**
CAPEX ($AUD/kW)	3,757	8,965
Fixed cost ($AUD/kW/Y)	17	81
Variable OPEX ($AUD/MWh)	7.5	8.2
Efficiency (HHV %)	40	25
Fuel Cost (AUD/GJ_{HHV}$) ($AUD/Tonne)	**17.70**	2.10 62
LCOE ($AUD/MWh)	**251**	**251**

Of the fossil fuel-based CCS technologies,
coal-based CCS is the most likely help decarbonise the Australian NEM.

The Impact of Changing Modelling Input Parameters – Doubling Gas Input Cost

In many of the lower carbon future scenarios, gas generation plays an important role in providing peaking and firming capacity, even though they often have widely varying utilisation factors during the year (refer Figure 9). This is very consistent with their current operations in many grids today. [67]

The world has seen large changes in the price of domestic and internationally traded gas recently. To understand the sensitivities, the gas price was doubled from $AUD 12.25/GJ to $AUD 24.50/GJ, but the generation profile was not re-optimised (simulating an unexpected increase in gas price with no time make significant adjustments to the generation profile).

The impact of the gas price doubling on total system cost varies significantly depending on the level of decarbonisation achieved. A plot of the base and increased gas price impact is given in Figure 10. At low levels of decarbonisation, gas plays a larger role within the generation mix, so any increase in fuel costs will have a more significant impact. At deep levels of decarbonisation, gas runs much less, so the cost of fuel has less of an impact on the total system cost.

As a side note, if existing unabated coal remains in the generation portfolio, the interplay between running coal as a peaking plant versus gas will be very price dependant. In all likelihood, as the price of gas increases, the cost effectiveness of refurbished coal plants operating as peaking will improve.

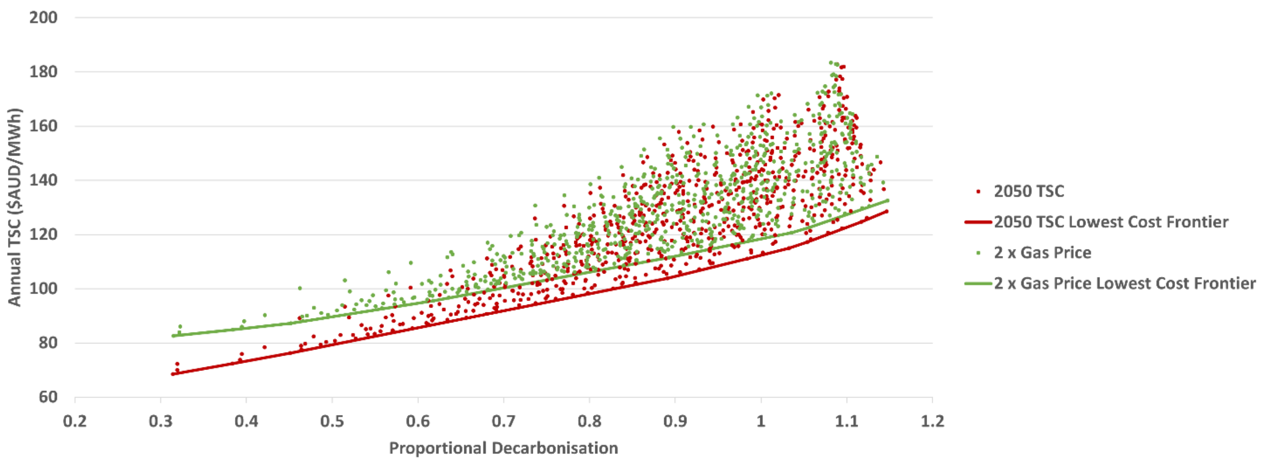


Figure 10: Double average gas fuel price, $AUD 12.25 to 24.50 per GJ

The current Australian NEM rules operate so that the supply offer that meets the temporal demand threshold, sets the price of electricity to the consumer. Therefore, peaking gas generation is often the dominant influence in the pricing. So, while the effect on cost is relatively small, the effect on price to the consumer would be much larger if the market is still configured to allow gas to set the power price. [67, 83, 84]

The Impact of Changing Modelling Input Parameters – Decreasing CCS CAPEX Input Cost

The Australian Commonwealth Scientific and Industrial Research Organisation (CSIRO) regularly provide an updated cost estimate for large-scale electricity generation in Australia via their GenCost reports. [85] Figure 11 shows the CAPEX estimates for 2030 from the GenCost datasets from 2018 until the current 2023-24 draft. The GenCost dataset aims to include current technology costs and technical operating parameters for both existing and emerging generation technologies, including those with minimal current local or international deployment. There are two parts to GenCost (within this report, GenCost will be used to cover both elements as relevant):

- Consultant based technology cost and performance review.
- CSIRO based analysis of the current costs to provide future technology cost estimates.

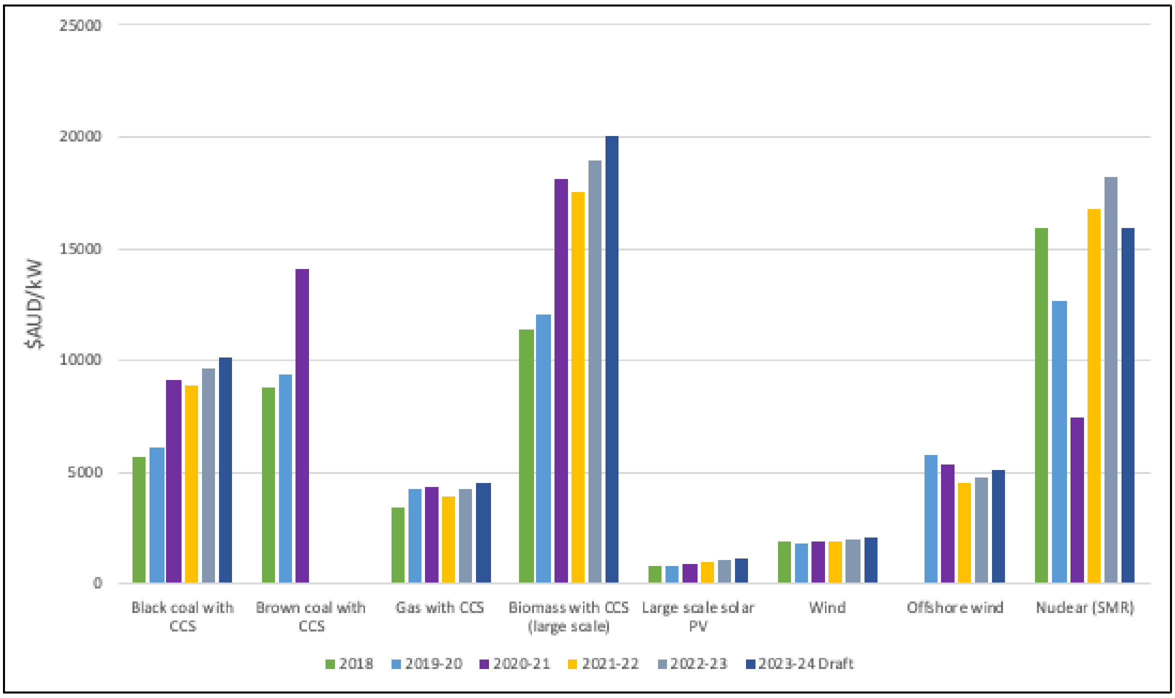


Figure 11: Australia's CSIRO GenCost CAPEX changes over time (2030 CAPEX projection)

There is considerable uncertainty within the BECCS and CCS capital cost estimates in Australia given none of these technologies has been constructed in Australia. Work done by others [86] suggests that a 30% reduction from the last costs was a reasonable test of the more extreme impact of a CAPEX cost reduction. The impact on the lowest cost generation stack and subsequent flow on to the generation profile of this CAPEX reduction is shown in Figure 12.

There are several key impacts on the 2050 scenario due to the 30% reduction in CAPEX for both BECCS and CCS. The overall generation capacity has reduced from more than 200GW to just over 150GW. This substantial change is due in part to a large reduction in solar PV generation plant and a subsequent reduction in energy storage. Excess solar PV capacity to charge energy storage is no longer required in the new scenario. This is due to the larger capacity of low emissions, dispatchable CCS plant. The increase in capacity of CCS, from 4.3GW to 15.0GW due to the cost reduction has resulted in much less use of batteries and the solar PV required to charge it. And while there remains some curtailed energy in this scenario, it is a relatively small amount, meaning the overall system is relatively efficient.

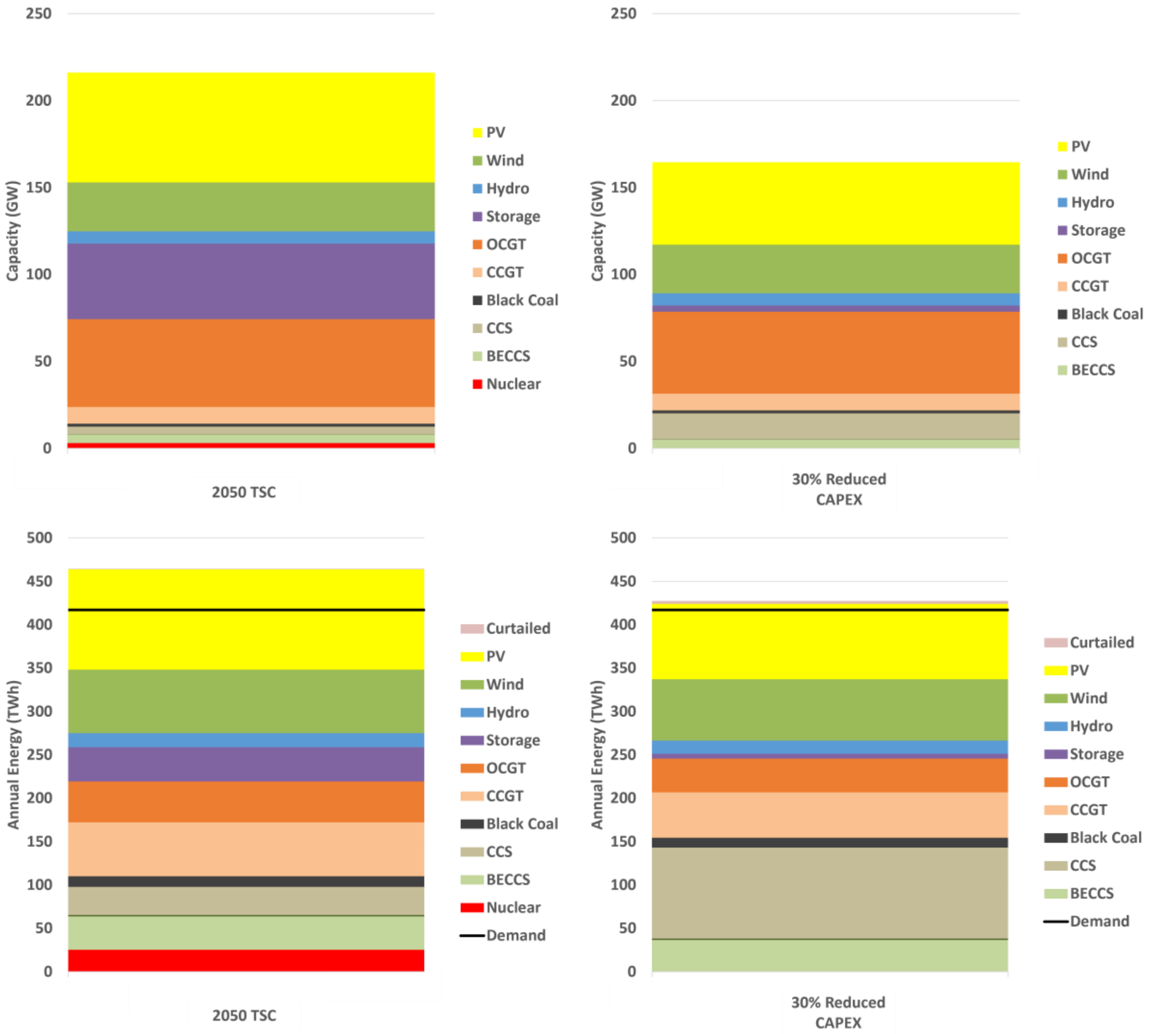
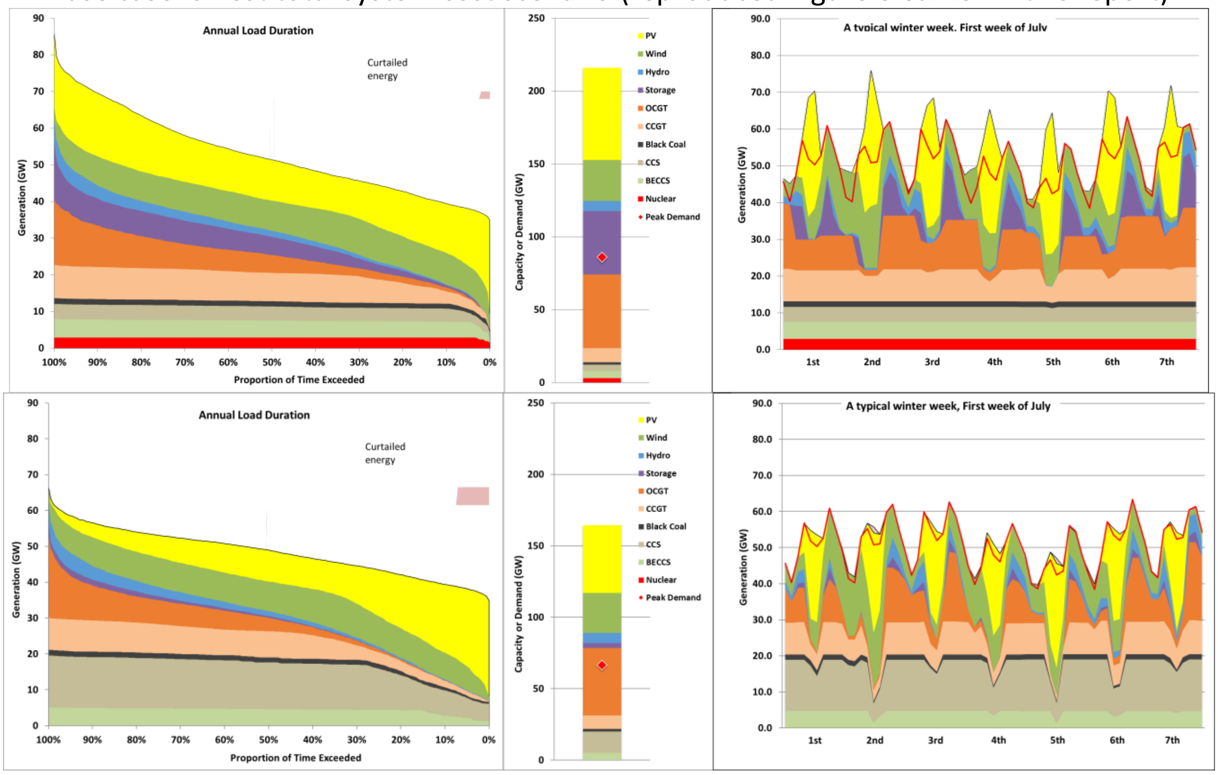


Figure 12: Base case versus BECCS and CCS capital cost reductions

The reduced CAPEX scenario for CCS also leaves no room for nuclear capacity in the lowest cost scenario. It is important to note, however, nuclear and CCS in the reduced CAPEX scenario both trend on the lowest cost frontier. So relatively small changes in generation costs will likely mean that CCS and nuclear may substitute for each other.

Comparing the different annual load durations and how the system could function during a complex winter weather week is shown in Figure 13. Here the difference in storage is very noticeable, playing only a minor role within the grid. The role of the gas generation remains very similar in the two scenarios, with BECCS used to offset the associated emissions. The CCS plants also play a similar role for much of the year, being dispatched at near full capacity for more than 70% of the time. However, it is required to be much more flexible for around 30% of the year, with an example of its required flexibility shown on the 2nd and 5th days of the complex weather week, being required to be a minimum generation for a time.

Base case lowest total system cost scenario (reproduced Figure 8 earlier in this report)



30% CAPEX reduction scenario

Figure 13: Impact of BECCS and fossil CCS CAPEX reduction on the Australian NEM

Strong Renewable Push Followed by a Technology Agnostic Approach

Australia is committed to cutting domestic carbon emissions with plans to become a major global supplier of renewable energy, ramping up solar PV, onshore, and offshore wind capacity, and upgrading the grid. Australia has targets of reducing greenhouse gas emissions by 43% from 2005 levels by 2030 and net zero by 2050. This is backed by Australian Government investments to deliver climate change and energy transformation priorities, [87] including:

- Transforming Australia's electricity supply to run mainly on renewables.
- Supporting the development of new, clean energy industries.
- Supporting the decarbonisation of existing industries and transport network.

In this study, we examined the impact of key decarbonisation targets with a heavy renewable technology focus until 2040, followed by a technology agnostic approach to reach 2050. To give the transition every advantage in this scenario the following were included as the 2040 base:

- Maximum likely interconnection.
- Maximum likely pumped storage schemes.
- Renewables added to achieve 90% decarbonisation.
- CCS and nuclear technologies not deployed.

From this strong renewable base, delivered by 2040, all constraints were then relaxed to examine what the lowest total system cost would then look like in 2050. The transition allowed for the following to be added between 2040-2050:

- Coal and gas CCS.
- BECCS.
- Nuclear.
- Renewables.
- Batteries.

The Characteristics of a 2040 Strong Renewables, 90% Decarbonisation Scenario

The highly renewable 2040 generation portfolio, at 90% decarbonisation, is shown in Figure 14, with only residual coal generation left running and a relatively small amount of open and combined cycle gas generation capacity. The generation fleet is dominated by wind and solar PV at nearly 140GW of combined capacity out of nearly a 250GW fleet. As expected, the annual generation in 2040 is dominated by wind and solar PV.

It should be noted that there is also a significant amount of curtailment in the 2040 scenario, with around 12.5% of energy lost through curtailment. This curtailment occurs despite over 50GW of installed storage capacity. Coal and gas run across the entire year, though gas mostly operates as a peaking generation asset when its needed. Fossil fuel generation technologies are still required to run to support parts of the grid that has insufficient renewable generation, whilst at the same time wind and solar exceed all options for its utilisation (demand, storage filling and interconnector exports) in other states.

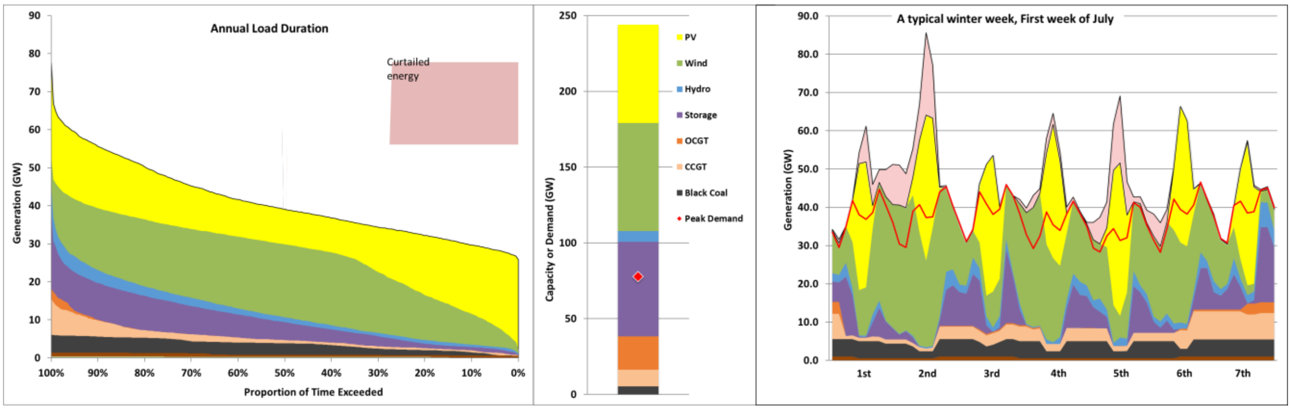


Figure 14: The 2040 renewable promoted, 90% decarbonisation scenario

The 2040 Strong Renewable Scenario to a Net Zero, Unconstrained 2050 Scenario

With the 2040 scenario defined as the base, the 'all constraints and technology agnostic' option to 2050 scenario was developed. With all forms of CCS and nuclear now added to the technologies available for the transition to 2050.

The capacity development to meet net zero in 2050 from the highly renewable 2040 scenario is shown in Figure 15. As shown, there is nearly no increase in overall capacity, however, there is a deployment of BECCS and an increase in open cycle gas generation. Coal has almost no generation plants remaining in 2050. The generation contribution of wind and solar PV remains dominant, importantly though, there is significantly less curtailment in the 2050 scenario. This efficiency is a key element of the scenario. The BECCS / natural gas combination is again central to being able to achieve net zero and bring the grid towards the lowest total system cost scenario – even after a strong renewables and storage push to 2040.

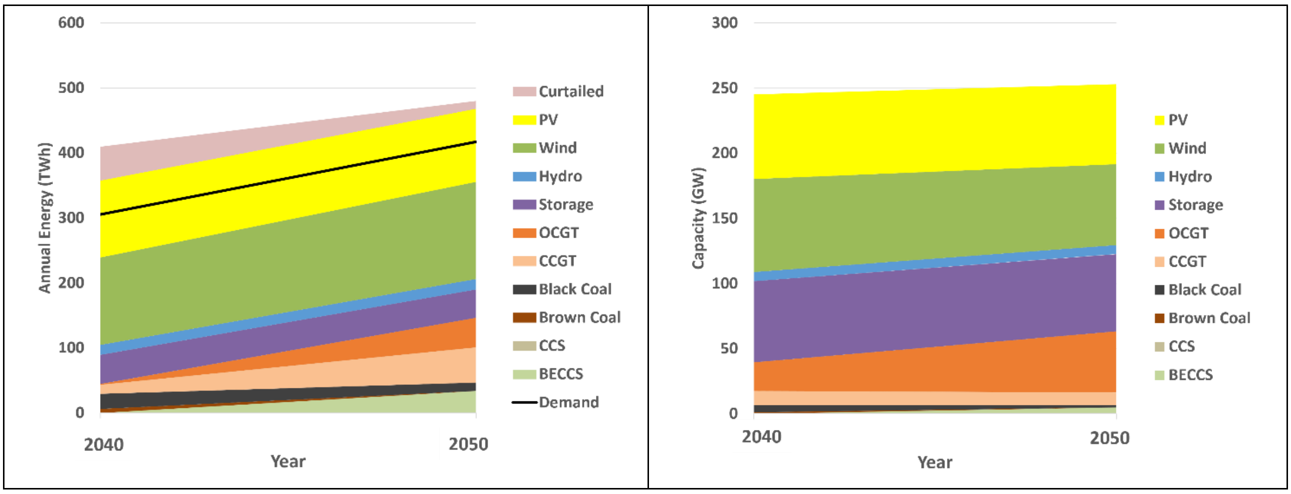


Figure 15: 2040 to 2050 generator portfolio development from a strong renewable grid

The operation of the 2050 grid after the strong renewable push shown in Figure 16, it has some similarities with the lowest cost solution of Figure 8. BECCS is there to soak up (off set to net zero) emissions from the mid-merit and peaking gas that has been added. However, there is no fossil-based CCS in this scenario, the existence of the large portfolio of renewables and its attendant periods of curtailment means the resultant low load factor running of CCS is uneconomic.

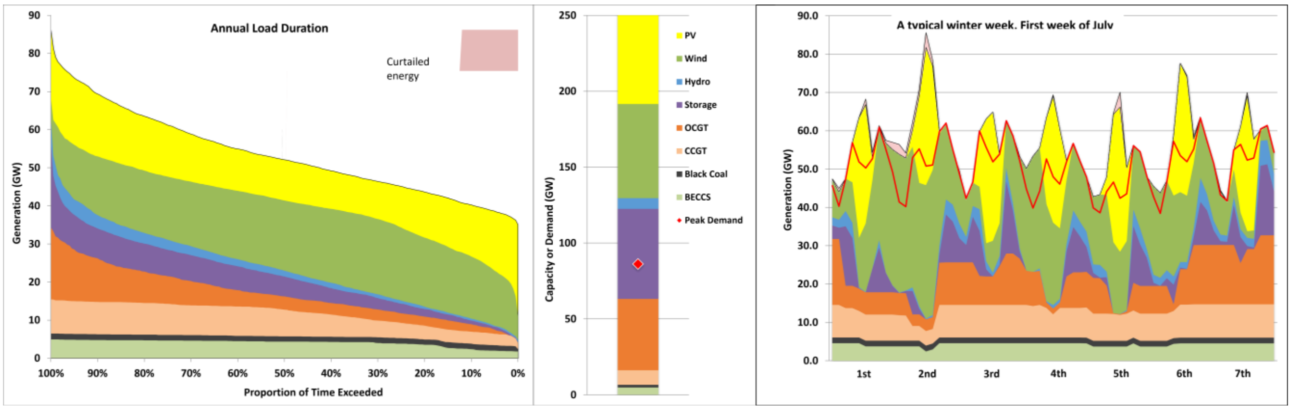


Figure 16: The 2050 scenario development from a strong renewable grid

The Cost Impact of a 'U-Turn' in Grid Technology Options

The technology agnostic, 2050 lowest total system cost frontier (red line) is reproduced in Figure 17 and compared to the strong renewables 2040 grid frontier (green line). The 2040 strong renewable frontier follows a similar pattern to that seen previously – with costs rapidly increasing as decarbonisation increases. It also is not able to reach net-zero. [38, 55, 67] The high level of curtailed energy is a significant factor in high cost of decarbonisation.

Moving from the strong renewables 2040 grid to a net zero 2050 grid with relaxed constraints on the possible grids of the future was not without a cost impact. As shown in Figure 17, the 2040 to 2050 with relaxed constraints cost frontier (blue line) is always above the lowest total system cost frontier. This is due to the over build of renewables now on the system, which prevents the lowest cost to be achieved. This is a $AUD 10/MWh penalty along most of the frontier.

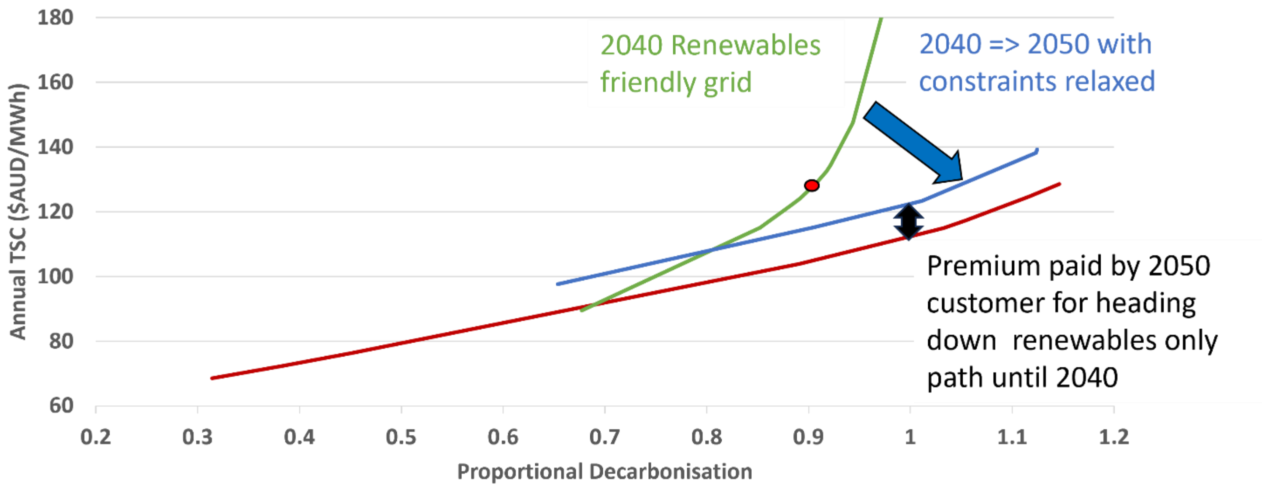


Figure 17: Impact of relaxing constraints on the cost frontiers

Changing course on decarbonisation makes for an expensive U-turn – planning to build the lowest total system cost system from the start saves money.

The risks due to unintended consequences of constraining options of a future grid are somewhat dependant on when a change in course occurs. As shown in Figure 17, the strong renewables grid begins to diverge at around the 60 – 70% proportional decarbonisation level. If constraints are relaxed at the 70 or 80% level, that would result in a lower total system cost solution in 2050 compared with the 90% chosen in this study.

The Role of BECCS in the 2040 to 2050 Transition

The net emissions at 15.6MT in 2040 (90% renewable decarbonisation scenario) reduce to 0MT in the 2050 net emissions scenario, as shown in Figure 18. Importantly, the additional capacity added to transition from 2040 to 2050 saw an increase in both gas-fired generation and BECCS. The total emissions in the 2050 scenario increase from 2040 and are offset by the negative emissions associated with BECCS. The important role of BECCS in decarbonisation and achieving net zero should be considered in future grid planning and understanding the resources that are available to grid planners in the future.

In the current Australian NEM, unabated coal, and gas accounts for a significant share of both capacity and generation. However, it is expected that unabated brown and black coal will have to be mostly replaced by lower emissions technologies, including renewables, storage and CCS. This is confirmed by this study and prior work [38], which shows that decarbonisation of the grid will greatly diminish, although not necessarily completely eliminate, the role of unabated coal.

However, the utilisation of BECCS at almost all levels of decarbonisation facilitates generation scenarios to remain on or close to the lowest total system cost frontier (refer to Figure 7 which demonstrates the key role of BECCS). More specifically, after a strong renewable grid development by 2040, BECCS is a key technology in transitioning to a net zero lowest cost scenario by 2050, as shown in Figure 15.

How BECCS contributes to the net zero outcome is shown in Figure 18. In 2040, the total emissions of the system are just under 16MT of CO_2, a 90% decarbonised scenario. However, total emissions *increase* by 2050 to just over 43MT, but they are completely offset by BECCS. The bio sourced CO_2 which is then sequestered is key to allowing unabated gas to run, keeping the system at its lowest possible cost.

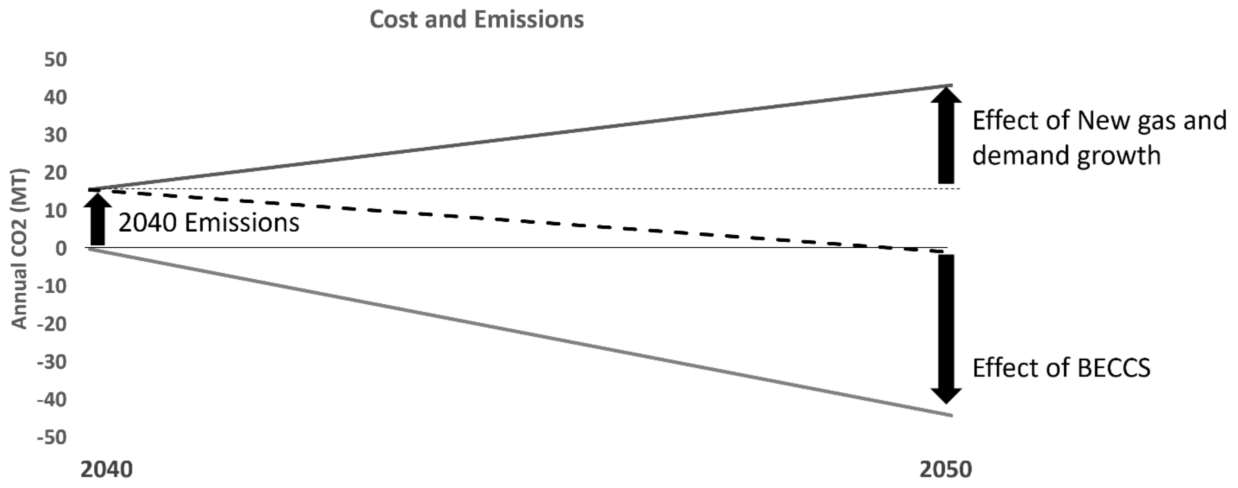


Figure 18: The vital role of BECCS in the 2040 to 2050 transition

This is consistent with previous work, [38] where MEGS was used to model the Australian NEM[2]. The decrease in emissions associated with CO_2 emitting technologies at different decarbonisation targets is shown in Figure 19. It is very clear that the role of unabated brown and black coal decreases as decarbonisation targets increase. These emissions are replaced with natural gas, then with fossil CCS and finally with BECCS. As in this current study, BECCS was shown to provide an offset opportunity for unabated emissions within the lowest TSC solutions at 95% and 100% decarbonisation. [38]

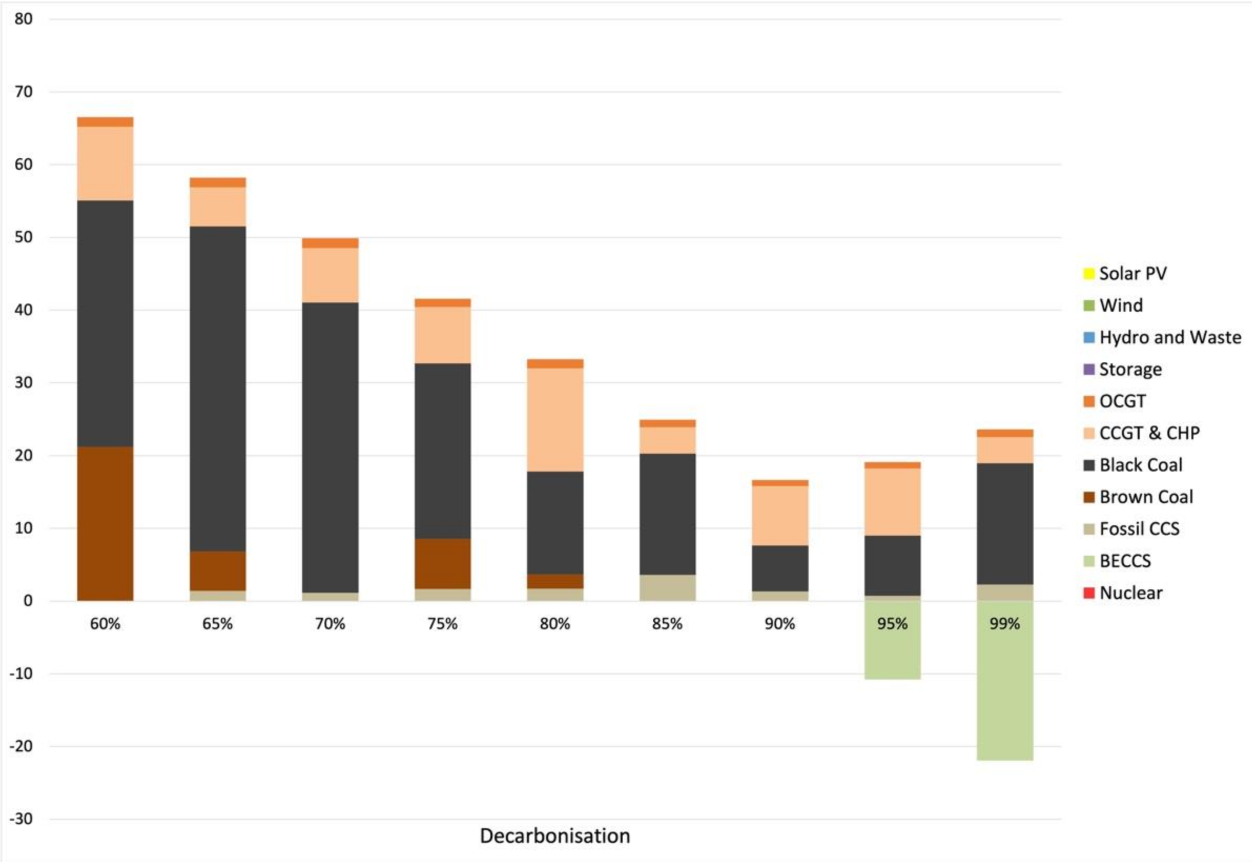


Figure 19: The source of CO_2 emissions at the lowest TSC frontier in 2050 for the NEM (prior work)

It is important to understand how and why unabated coal remains on the system in a deep decarbonisation scenario. Specifically, why is unabated coal or gas being used as a peaking plant and high merit and expensive BECCS is being used to net out their emissions?

[2] It should be noted that this prior study uses different model assumptions and inputs – so if this work was reproduced with the current assumptions – the results would vary slightly.

Firstly, it is important to consider the residual load duration curves in the deep decarbonisation scenarios, net of both wind and solar PV. This remaining load needs to be met by firm capacity. This is shown schematically in Figure 20. In this figure, we can see the 'traditional' view of peaking plant on the left-hand side, where open cycle gas power plants provide peaking capacity and the BECCS power plants offset its emissions, as well as the emissions from the fossil CCS plants.

Fossil CCS plants capture the majority of emissions, but have a 5% slippage, which needs to be offset at very high decarbonisation levels. When unabated coal is used as a peaking plant, it has higher CO_2 emissions than open cycle gas due to the higher carbon content of the fuel, however BECCS completes the offset for coal as for gas.

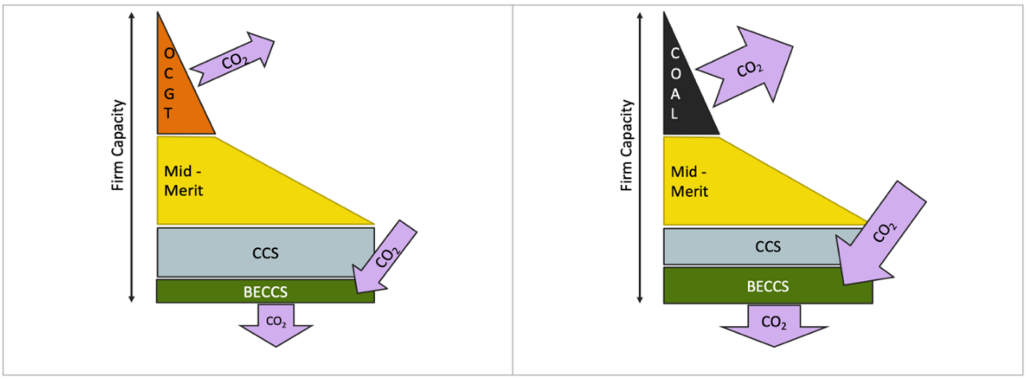


Figure 20: The role of peaking plant in deep decarbonisation – open cycle gas vs very flexible coal

Japanese Modelling and Scenarios

Grid Background

The Japanese electricity grid comprises two major interconnected systems: the Eastern Japan grid and the Western Japan grid (refer to Figure 21). [88] These grids serve distinct areas of the country, each with its unique characteristics and energy compositions.

The Eastern Japan grid caters to the densely populated regions in the eastern part of the country, including Tokyo and its surrounding areas. Operating at a frequency of 50 hertz, this grid relies on a diverse energy mix to meet the demands of its extensive population. It draws a significant portion of its power from coal and natural gas sources. Nuclear power also plays a vital role in the energy composition of this grid, contributing to its reliability.

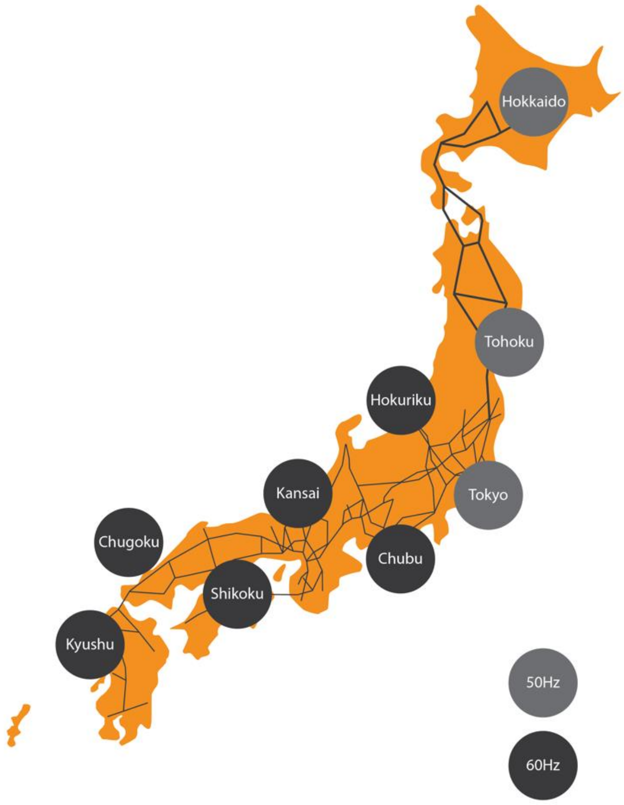


Figure 21: The Japanese electricity grid

In contrast, the Western Japan grid covers the western part of the country and operates at a frequency of 60 hertz. Despite the difference in frequency, the Western Japan grid shares similarities in its energy composition. Like its eastern counterpart, this grid relies heavily on thermal fossil and nuclear power sources to meet electricity demands.

The historical development paths of the two grids have led to the frequency difference between them. However, this frequency gap is addressed using frequency converters at interconnection points. Although these devices enable the exchange of a small amount of electricity between the Eastern and Western grids, their capacity is less than 2% of the generation capacity in each grid, so the grids act relatively independently.

Scenarios & Assumptions Summary

MEGS models regions with interconnectors that can carry both energy and reserve services. When MEGS is configured for the whole Japanese grid, it treats it as an 'islanded' grid that consists of two different frequency grids with relatively weak interconnection. The constraints (detailed in Figure 3) are applied in each region, with interconnector allowing transfer of energy or reserve services to fulfil those needs. The relative weakness of the interconnectors means that inertia (which is also a proxy for local system strength and fault levels) cannot be transferred from region to region. Likewise, it is assumed that each region will need to be able to cover its own demand with sufficient firm generation and storage capacity. Therefore, the minimum requirements for these must be met from within each region.

The Value of Hydrogen Storage in the Japanese Power Grid of the Future

Given the need to decarbonise the electricity sector and the advantage of using every available technology, expectations have been raised for the use of hydrogen (or its derivatives[3]) to generate power, since as a fuel, it produces no residual CO_2 emissions. [89-91] Even though the current decarbonisation using hydrogen is very small, [90] hydrogen is being pursued as a promising technology.

For hydrogen-based power generation technologies to be considered reliable and dispatchable, fuel access will be crucial. How hydrogen is produced, its mode of transport, the transport distances and its storage options will all impact its cost and availability. For this study, the cost of the hydrogen storage cycle was considered a key screening parameter for its utilisation as a low emission, dispatchable firm generation technology option.

Adding varying increments of hydrogen storage, measured as generation capacity, to the Japanese power grid is shown in Figure 22. The lowest cost frontier has no hydrogen contribution, and just 5GW of hydrogen raises the cost frontier by $USD 6-10/MWh in a 500GW generation capacity system. Increasing the level of hydrogen storage progressively increased total system cost.

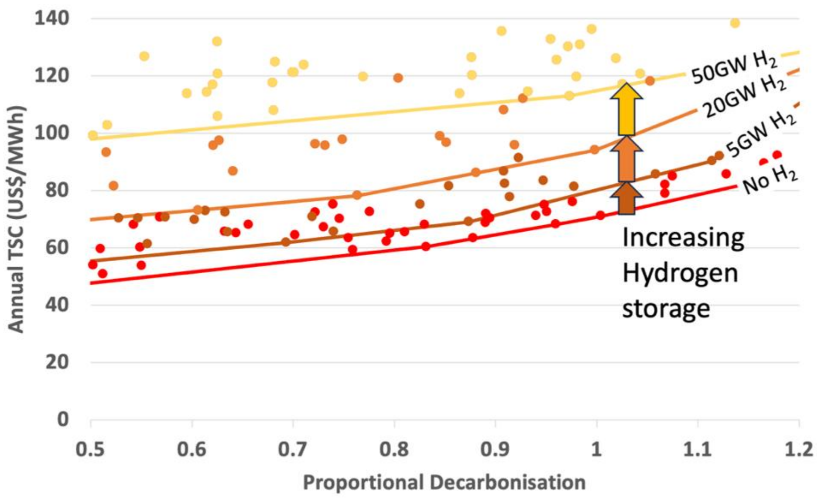


Figure 22: The value of hydrogen storage in the Japanese grid

Since any scenario with hydrogen storage would be excluded from the lowest total system cost frontier, the use of hydrogen was not considered for further analysis.

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[3] In this report, hydrogen is the being used as a general term for all hydrogen fuel derivatives including for example ammonia.

The Relevance of Wind Power for the decarbonisation of the Japanese Power Grid

According to Ember [92] only 0.8% of electricity in 2022 came from wind, compared to 10% from solar. A number of reasons have made it difficult gain a foothold in Japan:

- Shortage of suitable land for onshore windfarms (only 0.9% of land is available for renewable energy and most of that competes with other developments). [93]
- Lack of shallow waters for fixed offshore windfarms. [94]
- Poor load factors and hence economics.

Taking these together it was decided to rule out onshore wind. Even if 3 or 4 times as much got built it would still be insignificant in a system with growing demand. Offshore wind (fixed foundations) was made available to MEGS in some initial runs but scenarios that included even as little as 20GW (on a 500GW system) were around $USD 8-10/MWh more expensive than those without (see Figure 23). Hence it was decided not to explore wind of any kind.

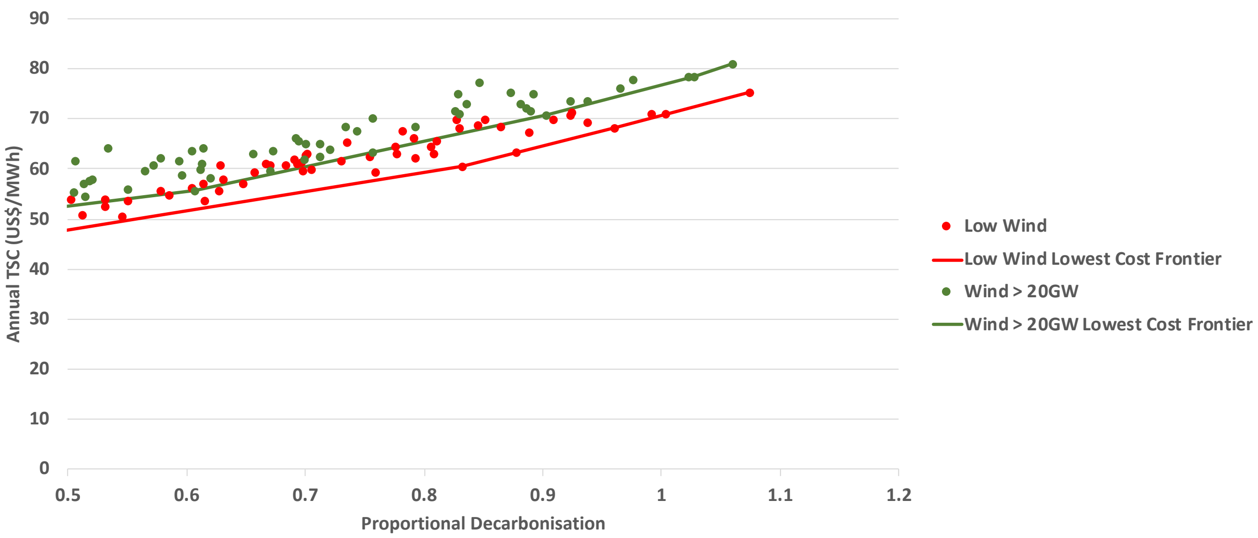

Figure 23 Effect of offshore wind on the lowest cost frontier for Japan

Lowest Cost Solutions for the Japanese Power System

The transformation of the Japanese electricity grid from its current nuclear, unabated coal and gas backbone into a net zero or beyond will take a massive change. Using the MEGS model with six different generation technologies whose capacity could be varied, more than 700 possible future Japanese grids where explored. Each scenario was a different combination of zero, half or max capacities for each technology. In addition, more than 100 scenarios around the net zero target were explored to better define the lowest cost frontier and find the optimum net zero scenario.

From no additional decarbonisation, to beyond 120% decarbonisation, MEGS was used to determine the lowest cost frontier and the optimum net zero solution. The results of this work are provided in Figure 24. Consistent with the Australian work described in Figure 6 and other work the total system cost of the transition ALWAYS increases with the level of decarbonisation and the frontier always gets steeper as decarbonisation progresses. [19, 24, 38, 67]

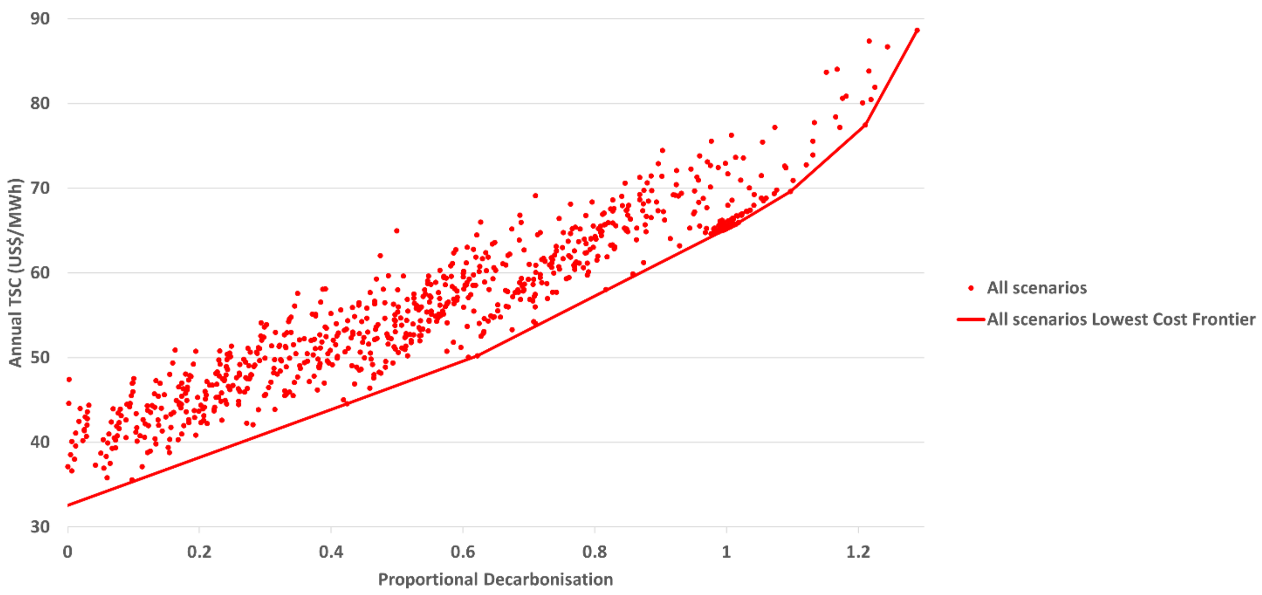

Figure 24: The Japanese Grid with more than 800 possible 2050 futures – targeting the lowest cost frontier

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Even with a strong nuclear base, further decarbonisation of the Japanese grid will increase the cost of electricity.

The Impact of Constraining Low Carbon Dispatchable Technologies

Understanding the implications of technology constraints within a future system is an important element of understanding what building blocks may be used to create a net zero electricity grid. By excluding some technologies, different total system cost frontiers emerge.

Figure 25 demonstrates the impact of constraining or not pursuing BECCS, coal or gas CCS or nuclear technologies. The absence of coal or gas CCS technologies does not have an impact on the lowest total system cost solutions. No nuclear begins to have a significant cost impact on the cost frontier from approximately the 70% proportional decarbonisation level. However, the absence of BECCS has the largest impact – even more significant than within the Australian context (refer Figure 7). Without BECCS, net zero is not possible in the scenarios examined. In fact, the absence of BECCS increases the total system cost in all scenarios examined.

The importance of BECCS is also clearly demonstrated in Figure 25, with the BECCS cost frontier above the lowest total system cost frontier at all decarbonisation levels. Constraining BECCS as an option clearly increases any generation scenario, however, the most significant impact is the inability for the system to achieve more than 70% decarbonisation with the capacity constraints considered in this study. Even then, it costs approximately $USD 18/MWh more than the lowest cost frontier at the same decarbonisation level.

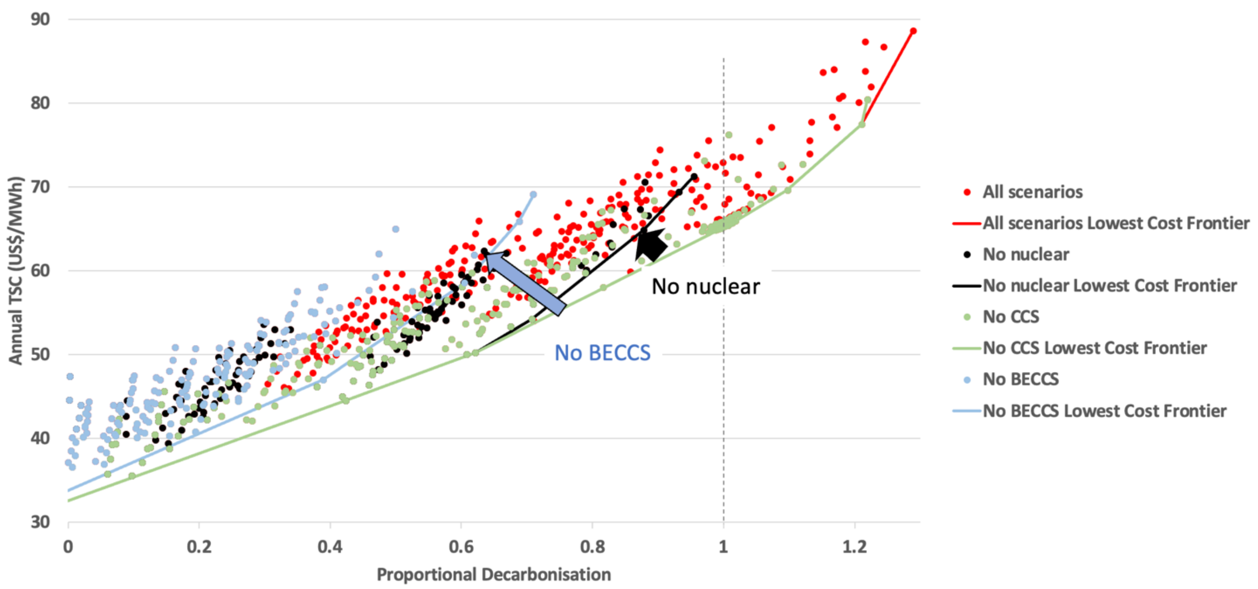

Figure 25: The Japanese Grid with more than 800 possible 2050 futures – impacting of technology constraints

BECCS is a critical technology in the portfolio.
Without it net zero is impossible.

BECCS as the only carbon negative generation technology, its unavailability due to physical storage or biomass supply constraints or policy is makes a significant impact on the possible solutions and the decarbonisation depth possible.

Characteristics of a 2050 Lowest TSC Japanese Grid Generation Stack – No New Nuclear

Energy security is becoming of more significant concerns to countries around the world due to the limited energy sources, increasing population, energy prices fluctuations and limitations in energy supply. Japan is one of the largest energy consumers and energy importers, with almost 96% of its primary energy supply imported from other countries. Japan has long realised the sensitivity of its energy supply and relies on diversification of generation technologies to manage risks. [95] Within the context of a diverse generation portfolio, two least cost options were explored. The first option did not permit new nuclear to be opened but allowed the current 28GW to be refurbished and brought back online, the second limited nuclear build to reach a total of 60GW.

Without additional nuclear power, the generation capacity of a net zero 2050 would reach 450GW. As shown in Figure 26, the firm dispatchable, low emission technologies are BECCS and CCS. A combined total of around 100GW underpins the grid. Gas combined cycle plants also run as near baseload capacity, with open cycle gas operating as peaking plant. Renewables play a relatively minor role within the net zero system despite a large installed capacity of solar PV, in particular. Storage is charged with excess energy, however, the system has no curtailed energy, with an effective generation portfolio. BECCS plays a critical role within the net zero context, offsetting all the gas emissions. BECCS effectively offsets 294MT of CO_2.

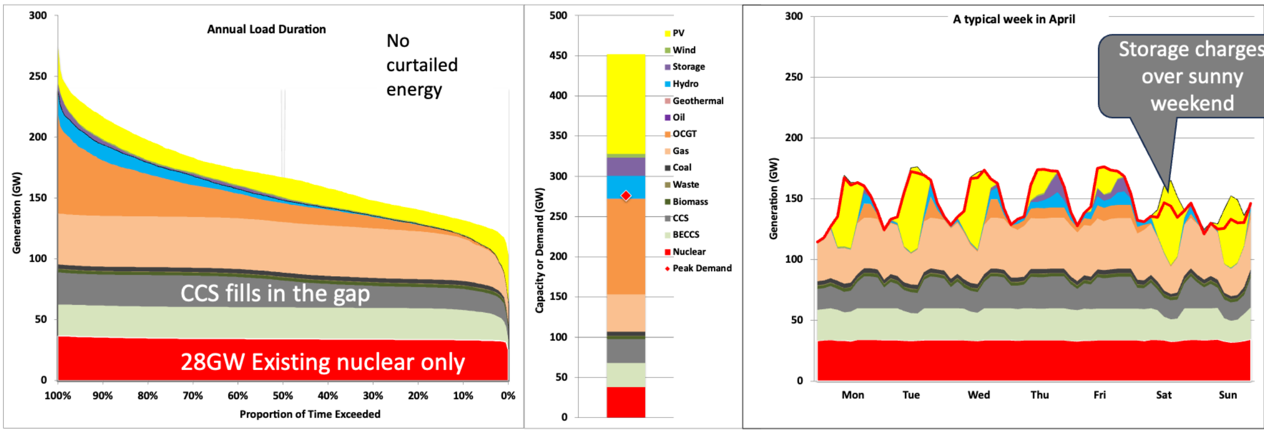

Figure 26: The lowest total system cost configuration of a net zero 2050 – No New Nuclear

If there is a nuclear renaissance which allows a further 22GW of nuclear build on top of the 38GW of existing nuclear coming back online, the lowest total system cost solution looks significantly different. As shown in Figure 27, gas and coal-based CCS is no longer part of the generation portfolio. However, nuclear power and gas or coal-based CCS are mostly interchangeable, with minor changes in CAPEX and fuel input costs changing the preferred solution. In the context of energy diversity, it is likely that coal would be a useful diversification alterative for low emissions generation and gas left to complete the mid merit and peaking duties required.

Nuclear underpins the system, essentially running at full load for the entire year. The role of combined cycle gas is significantly curtailed compared to the no new nuclear scenario and operates as a 'mid merit' plant (refer to Figure 20). The open cycle gas is both lower in capacity and runs significantly less and operates as a peaking plant.

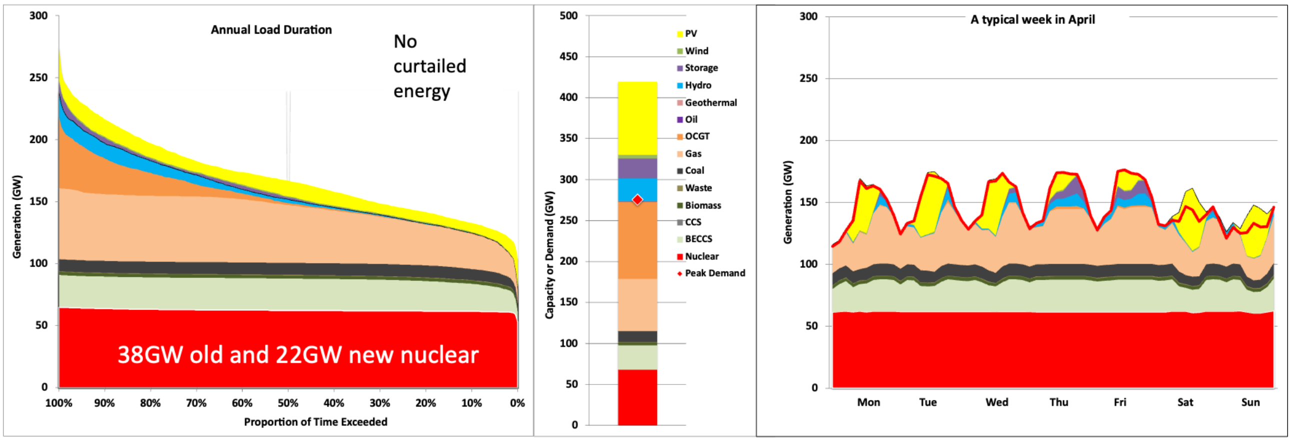

Figure 27: The lowest total system cost configuration of a net zero 2050 – 60GW Nuclear

Constraints and Influences on the Optimum Grid Makeup

In line with a range of international (e.g. the Paris Agreement [3]), national (e.g. Australian [96] & Japanese [97] Government plans), regional (e.g. Queensland, Australia's [98] and Kyushu Region, Japan's [99] plans), and self-imposed ambitions (e.g. BHP's [100] and MHI's [101] climate plan), Governments and corporations are continuing to make the necessary changes to the electricity generation mix with a view to achieving their decarbonisation goals. These changes, however, are not carried out in isolation, with those steering the energy transition likely having to navigate a range of constraints. [56, 102]

Constraints that may impact the makeup of an optimum grid include many of the following:

- Technical issues.
    - e.g. Possible undersea transmission cables length, CO_2 pore space limitations, critical mineral availability, grid operability issues, the slower than expected development of new technologies.
- Policy issues.
    - e.g. Nuclear bans, fossil fuel exploration bans, buy 'local' policies, renewable-only mandates, a 'lock in' of carbon emissions by current policies.
- Societal issues.
    - e.g. Not in my back yard, lack of demand for low/zero carbon products, ensure an 'equitable transition,' competing land use.
- Corporate organisational issues.
    - e.g. Ability to access external funding, ownership structures, shareholder activism, potential profitably while decarbonising, limited collaboration between corporations.

Transiting from our current unabated black and brown coal, and gas electricity generation sources will be a critical element of the low emissions grid of the future. An optimum low emissions grid will require a significant contribution from renewable energy sources as well as dispatchable, low emissions generation such as coal, gas, and/or biomass with carbon capture and storage along with nuclear power. [38, 55] Prior work has also demonstrated that constraints applied to technologies that limit a possible 2050 decarbonisation transformation will result in a less than optimum total system cost grid. While some constraints may be physical and others policy driven, it is clear that these constraints need to be minimised where possible to ensure we have the best portfolio of assets delivering low emissions electricity. [56]

When modelling options for the makeup of a future grid, many modelling considerations must be taken into account. The MEGS model, described in the previous section, covers serval specific constraints in relation to the competency / security and reliability of the future grid. These are grid operability style constraints (refer to the following section of the report).

However, like others, the constraints listed above, and those in described in more detail in the following section (expect grid operability), are often explored as scenarios. For example, what if nuclear is not a viable technology solution, what if wind and solar are too difficult to connect to the grid and or what if land access limits utility solar or large scale onshore wind deployment.

Grid Operability

Four primary elements make up the modern electricity grid: generation plants, storage systems, electricity transmission and distribution infrastructure and finally, industrial, commercial, and household consumers of electricity. The grid is not static system, undergoing continuous change, with new generation plants being added, plants retiring, additional transmission lines being rolled out, customer reducing load via energy efficiency and increasing load by expanding operations. [38]

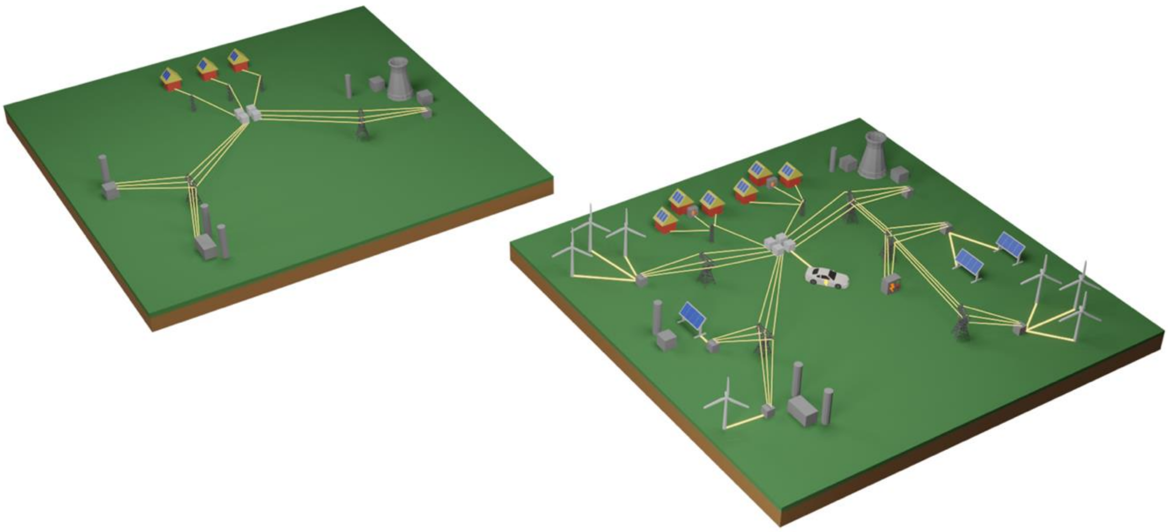

Figure 28: Centralised to decentralised grid transformation

Over the past 10 to 15 years, most modern electricity grids have seen a dramatic rise in wind and solar electricity generation. [73] This increase in variable renewable generation, and a resulting reduction in coal and gas-based synchronous generation has led to operability challenges. [74, 75] While a highly renewable system may exacerbate the operability challenges, there exists a great deal of uncertainty about the level of services that may be required in future, however, there is confidence that these can be met through deploying a range of available and developing technologies.

<u>Synchronous generators</u>: these are power plants that produce electricity that is directly coupled with the frequency of the grid. They generate through rotating alternators which are connected to large turbines that are all connected to spin at the same speed. Synchronous generators include coal, gas, nuclear, some hydro, and biomass.

Grid operations can be broken down into two high level elements:

- The need to balance supply and demand on a second-by-second basis.
    - Imbalances in supply and demand impact the grid frequency, which for reasons of operability has a relatively tight operating range.
- The need to manage the costs of the system.
    - If the system is too costly to run and maintain it may become internationally uncompetitive, with potentially economy wide implications. Hence the system is run to satisfy demand at minimum cost.

<u>Non-Synchronous generators</u>: these power plants that are connected to the grid via power converters, they are not naturally linked to the frequency of the grid. Variable renewables such as wind, solar PV and some hydropower are typically non-synchronous, alongside batteries and some pumped storage.

Within these high-level elements, there are key challenges of operating a modern electricity grid [75]. The four most important elements to maintaining a stable grid are ensuring adequate levels of:

- Maintaining a minimum level of system inertia.
- Frequency response service to maintain a stable frequency.
- Reserve power that can deliver on number of timescales ranging from seconds to hours to maintain balance.
- Reliable dispatchable power to meet demand at all times.

There are many other requirements that are more technical in nature, but the following are particularly noteworthy:

- Short circuit level / fault current.
- Voltage control & reactive power.
- System restoration "Black Start" services.

Inertia

Inertia in a power system refers to the energy stored in large rotating generators[4]. These large rotating masses are synchronised to the frequency of the power system. These machines are heavy, some tens or hundreds of tonnes, and provide mechanical inertia, as the machine spins at very high speeds with rotational kinetic energy stored in its mass. The kinetic energy is exchanged with the power system as electrical energy following disturbances that cause a change in the speed of the rotating machine. This electromagnetic response is instantaneous and inherent to the physics of the rotating machine. [75, 103] It should be noted that there will be some demand side inertia, such as from large synchronous motors – but this is not always well understood and has reduced over recent years as synchronous motors are replaced by more efficiency variable speed drives connected via an inverter.

Inertia is critical for a stable grid as it provides the fastest possible injection of active power when there are disturbances on the grid.

The amount of inertia required within a grid is driven by a range of factors, including [74, 75, 103-106]:

- The largest generation loss.
    - What is the largest generator, or power line feeding power into the system, that could trip, creating the largest energy imbalance.
- The largest rate of change of frequency (also known as RoCoF) that equipment connected to the system can tolerate.
    - The system needs sufficient inertia to ensure that rate frequency change is slow enough to prevent generation protection systems from tripping.
- The amount and speed of frequency response on the system.
    - Inertia doesn't solve the problem of imbalance, so much as 'buys time' for other systems to provide power.

[4] The authors of this report recommend the NREL report on Inertia and the Power Grid: A Guide Without the Spin as a worthwhile read as an overview of inertia's role in maintaining an operable power system. NREL/TP-6120-73856. https://www.nrel.gov/docs/fy20osti/73856.pdf (accessed Dec 2023).

A synthetic inertial response is the *emulated* inertial response from inverter-based machines. These systems are interfaced to grid frequency through power electronic devices. So while not providing synchronous inertia, work is currently underway to better understand the definition and role of synthetic inertia. [103, 106]

Frequency Response

Frequency response refers to actions taken to maintain frequency or restore it back to its nominal value. The most critical of these are those that can raise frequency when it is too low and are described by parameters such as how quickly they can react, how long they can maintain the action, what the triggers are and the sensitivity of the response. There may be a deadband – a frequency range within a tight tolerance of nominal frequency where no action is expected. Beyond that the sensitivity of the response (known as droop) is the proportional change in frequency needed to trigger a 100% swing in output. Markets for frequency response products are usually divided into classes according to the time needed to respond and how long it can be sustained. For example, the Australian NEM defines primary response as the capability to achieve a 5% change in output within 10 seconds of the frequency straying outside of the deadband which must be maintained continuously [107]. In contrast to that, Fast Frequency Response must be delivered within 2 seconds [108], a service with a faster timescale introduced to cope with a lower inertia system that will react more quickly to any imbalance.

Reserve

Uncertainties in demand, generator availability and transmission capabilities mean that it is sometimes necessary to run more generation than originally planned. This might be required on very short timescales (e.g. to quickly recover from generator trips), or slightly longer (e.g. to counteract weather forecasting errors). Reserve refers to the plant that is kept on standby, ready to start in a short period of time, or already generating but not at full load, so headroom has been created for increasing output. Whereas frequency response is an automated response to frequency being out of tolerance, reserve is called upon by the system operator when the forecasted generation is short or plant on frequency response has been utilised following an incident and needs to recover to a level where it can provide frequency response again. Plant providing reserve cannot utilise that capacity for generation, unless called to do so by the system operator.

Short Circuit Level or Fault Current

The electrical current that continues to flow when a fault occurs is known as the short circuit level, which is also referred to as a fault current or system strength. The short circuit level provides an indicative measure of the connected power generation plants that can provide the large surge of current demanded by the fault. Without this protection systems might not detect the fault and fail to isolate the circuit. Short circuit level is a location specific parameter. [75, 109]

In a system that has significant amounts synchronous generation plants, the short circuit level provided by these machines is high, meaning the system is more capable of maintaining voltage and frequency levels during a fault. As we see more non-synchronous, inverter-based generation plants connected to the system, there will be a decline in short circuit levels. [110]

A system is capable of running with low short circuit levels; however, it creates operability challenges, any voltage changes cause bigger disturbances, which travel further. If left unmanaged, these disturbances may trip generation plants or make the whole system go unstable.

There are three main ways that high short circuit levels contribute to the operability of the grid: [75]

- Safe protection system operation.
    - High short circuit levels allow the system the time to detect (and thus rectify) faults on the system. If the short circuit levels are too low, various protection methods build into the system may not have the time to operate and safeguard the system.
- Voltage control improved.
    - High short circuit levels limited the extent of voltage disturbances.
- Overall grid stability.
    - High short circuit levels enhance the probability of a rapid return to the normal function of the grid after a fault or disturbance.

Voltage Control & Reactive Power

Similar to frequency, during normal operations, voltage levels must be maintained within acceptable ranges at different points within the power system. Voltage control is manged through balancing the provision and absorption of reactive power. Reactive power differs from active power as it carries no energy due to the voltage and current being completely out of phase. The management of reactive power is necessary to ensure network voltage levels remains within required limits, which in turn is essential for maintain power system security and reliability. [76]

Like short circuit level, reactive power provision is an inherently a location specific issue.

Where voltage is too low, reactive power is needed to increase it, and where too high, reactive power absorption is required to lower it. [75] The need for reactive power depends on local conditions and is also impacted by the broader network conditions. Its provision, when local to the voltage issue, is much more effective than when further away.

Traditionally synchronous generators at coal and gas stations have provided the majority of the reactive power needed by the system, but as these close other sources will be required. Batteries with grid forming inverters, interconnector conversion stations, synchronous condensers, capacitors, reactors, and Static VAr Compensators may all be used to control reactive power and hence voltage.

Reliable Dispatchable Power

To continuously achieve the instantaneous balancing of supply and demand, the power system as a whole needs both resource adequacy and capability. This requires the availability of a diverse mix of centralised generation and distributed energy resources, demand response opportunities and network capacity. [76, 77]

To adequately supply the system, it is necessary to have enough reliable, dispatchable power to manage the full range of reasonably foreseeable outcomes. [76] This could come from generation, flexible demand or storage and has several key aspects including:

- Maximum demand conditions.
    - The ability of the system to meet the highest plausible system demand, even if it occurs infrequently.
- Rare dispatch conditions.
    - The ability of the system to meet demand outside the normal conditions for a given time of year, or time of day.
- Energy adequacy.
    - The ability of the energy resource mix to meet demand over a significant period of time, including differing and unusual seasons.
- Operating reserves.
    - The overall generation supply mix must be sufficiently flexible to provide not only the energy required but sufficient reserve to cover generator breakdowns, forecasting errors or transmission outages.
- Network capability.
    - That the transmission and distribution services have the ability to deliver sufficient power to consumers when to the required security standard (such as being robust against the loss of any one circuit).

Resource Constraints

At a global level, the long-term constraints on the availability of energy supplies is unprecedented in modern history. However, a paradox exists, while energy constraints pose a threat to the global economy, continued extraction, and use of unabated fossil fuels at current or increased rates is a dominant driver of global warming. Despite an awareness that fossil fuel resources are exhaustible, variable, and are subject to various constraints, most modelling and planning treat fossil fuel inputs as limitless. [111]

While energy constraints pose a threat to economies, continued use of unabated fossil fuels is a driver of global warming, adversely impacting economies.

Given the recent outcomes of COP28, [112] options to reduce fossil fuel use by constraining supply could include elements like removing subsidies, placing moratoria on coal and gas exploration, increasing fossil fuel production taxes, give supporting funding to prevent or at least limit coal and gas developments in developing countries. In summary, simply persuading countries to stop approving fossil fuel infrastructure.

Natural Gas Constraints

Production logistics of natural gas impact its availability, the constraints that may impact the availability of natural gas have short- and long-term available implications. Several of the constraining elements include:[5]

- Natural gas supply and demand energy flows are very finely balance on an hourly daily, weekly, monthly, and annual basis. Gas supply is a resource with a naturally, relatively rapid declining supply (flow) rate. Managing stable production requires investment. Globally, most of the gas is produced and consumed in the same country, however, there is extensive and growing global trade. As of 2022, the world produced approximately 4,100 bcm. Global trade was 810 bcm. Of this global trade, 330 bcm was via pipeline, a major reduction from 2021 (420 bcm) due mainly to loss of Russian pipeline exports into Europe. A further 480 bcm was traded as liquid natural gas. [73]
    - Consequently, the ability to respond to large and/or rapid changes in demand is limited and within wider energy system context. Very small changes in supply (or fear of supply) have large price impacts.
- Economic growth generally increases demand for energy, which needs to be met by increasing supply. Natural gas has certain functionality in power generation and other sectors more broadly, being flexible, reliable, relatively low carbon dioxide emissions compared to unabated coal, very scalable. Therefore, economic growth tends to lead to increase in demand for natural gas and the response is increased supply.
    - If this supply is not increased, prices increase, incentivising more production to meet supply, but there can be a significant time-lag in this. The supply response to increasing demand is based often on imperfect information, so the supply-to-demand balance is highly uncertain and risk is involved, especially on the supply side.
    - Price increases further change substitution patterns (and this can have negative greenhouse gas impacts). Evident in recent Russian supply shock, Europe saw a major increase in coal use as well as increase in use of traditional biofuels (wood & charcoal).

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[5] Thanks to Emeritus Professor Andrew Garnett, The University of Queensland for his input and assistance on this section of the report.

- Weather may disrupt gas supply directly at source. Severe weather increases gas demand, albeit for unpredictable lengths of time and total volume.
    - Very hot or cold weather may increase demand for cooling or heating, which may be met directly or via additional (gas-based) electricity supply.
    - Hurricanes / cyclones may impact on and offshore supply.
    - Very cold weather can also disrupt production.
    - Seasonality ('Northern hemisphere winter') significantly changes demand – increasingly in an uncertain way as some of the energy functionality of natural gas is substituted or part-substituted by other technologies (batteries or pumped hydro vs. peaking); or countries adopt stricter efficiency standards.
- Ability to store gas to help meet peak demand and to respond to gas demand volatility (rate of change to local peaks and lows and the changing size of those peaks and lows).
    - The level of underground storage has a significant influence on a system's ability to meet peak demand.
    - Similarly, the amount of gas stored as compression in pipelines (line-pack) is also critical to the smooth operations of supply to power generation and to other uses.
- Flow on impacts due to alternative fuel issues.
    - Delayed oil, liquified natural gas (LNG) or coal deliveries may increase gas demand. Gas supply restrictions, pipeline, or LNG, and/or price increases have been seen to increase coal use in the power sector at large scale. Also, in the power sector gas prices/shortages can drive greater diesel use. Higher gas prices, mean that the entry price for some storage technology easier (e.g. pumped hydro, batteries), but these are not yet fully functional substitutes in all jurisdictions.
    - Unfavourable weather conditions for solar and wind resulting in higher demand for gas powered generation – gas use in power generation and therefore gas demand is becoming more strongly coupled to the weather.
- Pipeline capacity.
    - Growth in demand centres for natural gas not always met with required pipeline capacity growth – particularly being able to manage infrequent system peak demand duties.
    - Open cycle gas generation intermittent and lack long term supply agreements and rely on peak gas availability.
- International supply chain resiliency.
    - Conflicts may significantly alter supply chain opportunities for the supply of gas (geographic sourcing dependencies).
    - Conflicts may significantly alter supply chain opportunities for the supply materials or components required to maintain, expand or build a gas network.
    - Conflicts may result in physical damage to supply infrastructure such as wells, pipelines or LNG export facilities.
- Investment uncertainty.
    - Strong decarbonisation pledges and fossil fuel reduction commitments likely to increase investment uncertainty, leading to reduced future supply options.
- Environmental concerns.
    - Methane leakage as part of Government methane pledges will increase scrutiny on production.
    - Water production and disposal issues, especially in low water access locations
    - Overall licence to operate issues associated with fossil fuel production.
    - Carbon dioxide emissions, reserve quality decreasing resulting in higher emissions.
    - Carbon dioxide emission mitigation required at the production of gas.

Coal Constraints

Like natural gas, coal production logistics impact its availability, the constraints that may impact the availability of coal have short- and long-term available implications. Several of the constraining elements include:

- Coal supply and demand energy flows are finely balanced on an hourly, daily, weekly, monthly, and annual basis. Coal supply is a resource with a naturally declining supply rate with production volumes and mine life relatively predictable. Managing continued and stable local and global supply requires long term investment, rapid increases in supply to meet demand are difficult to achieve. [73] Like natural gas, coal is mostly used by the producing country, with the world coal trade accounting for 19% of production with total world coal demand at 5,644MTce in 2021 and internationally traded coal just 1,135MTce.
- Economic growth generally increases demand for coal, which needs to be met by increasing supply.
    - If this doesn't happen – prices increase, incentivising more production to meet supply.
    - Both China and India have boosted investment in domestic coal production, but global production in 2021 struggled to keep pace with demand increases, causing coal prices to surge. Russia, the world's third-largest coal exporter, and its invasion of Ukraine complicated coal market dynamics. [73]
- Severe weather may disrupt supply and increase demand.
    - Hurricanes / cyclones may impact supply, potentially disrupting all parts of the supply chain.
    - Very hot or cold weather may increase demand for cooling or heating, via additional (coal-based) electricity supply, with surges not being able to be met with additional supply rapidly enough.
- Competition between fuel users.
    - Large volume users including power plants, iron and steel mills, paper mills, fertiliser plants may impact supply and pricing.
- International supply chain resiliency.
    - Conflicts may significantly alter supply chain opportunities for the supply of coal (geographic sourcing dependencies).
    - Conflicts may significantly alter supply chain opportunities for the supply materials or components required to maintain, expand, or build a coal network.
- Investment uncertainty.
    - Strong decarbonisation pledges and fossil fuel reduction commitments likely to increase investment uncertainty, leading to reduced future supply options.
    - Government interventions in the coal market with a range of potential impacts, including limiting profitability, changing the domestic/export parameters, restricting approvals, or making approvals too difficult.
- Environmental concerns.
    - Methane leakage as part of Government methane pledges will increase scrutiny on production.
    - Overall licence to operate issues associated with fossil fuel production.
    - CO_2 & CH_4 emissions, reserve quality decreasing resulting in higher emissions.

Land Use Constraints

The land currently used by the energy system globally is relatively small, especially when compared with agricultural land use. However, that does not mean expanding and changing land use to enable the roll out of new power infrastructure is not a challenging process. [113-116] Technologies harnessing renewable energy sources are characterised by having a power density several orders of magnitude lower than fossil fuels, and as such will require much more land [117]. [118] They are also likely to be built in significantly different locations than the current infrastructure. As global energy is predicted by many to more than double by 2050 and more extensive land use technologies being deployed, there is a need to consider the various elements of land use as an important input in assessing energy planning systems.

While land use footprint is often not considered when assessing generation options for future decarbonised power grids, [119] as they often project possible grid configurations for many years into the future, land use is becoming a more of a ‘here and now’ issue for grid planners.

The range of issues that a changing energy generation mix on land faces include:

- Amount of water usage.
- Raw materials consumption from additional mining, and its associated land impacts.
- Localised pollution from generation activities.
- Displacing of, or significant impacts on natural ecosystems.
- Land degradation, including increased erosion and deforestation.
- Changes in land access or denied access.
- Trade-offs for food production, urban development, conversation, visual amenity, cultural heritage.

Figure 29 seeks [120] build on prior work [121] to illustrate some of the complexity of the linkages within the nexus of climate change, land, security, cooperation and conflict.

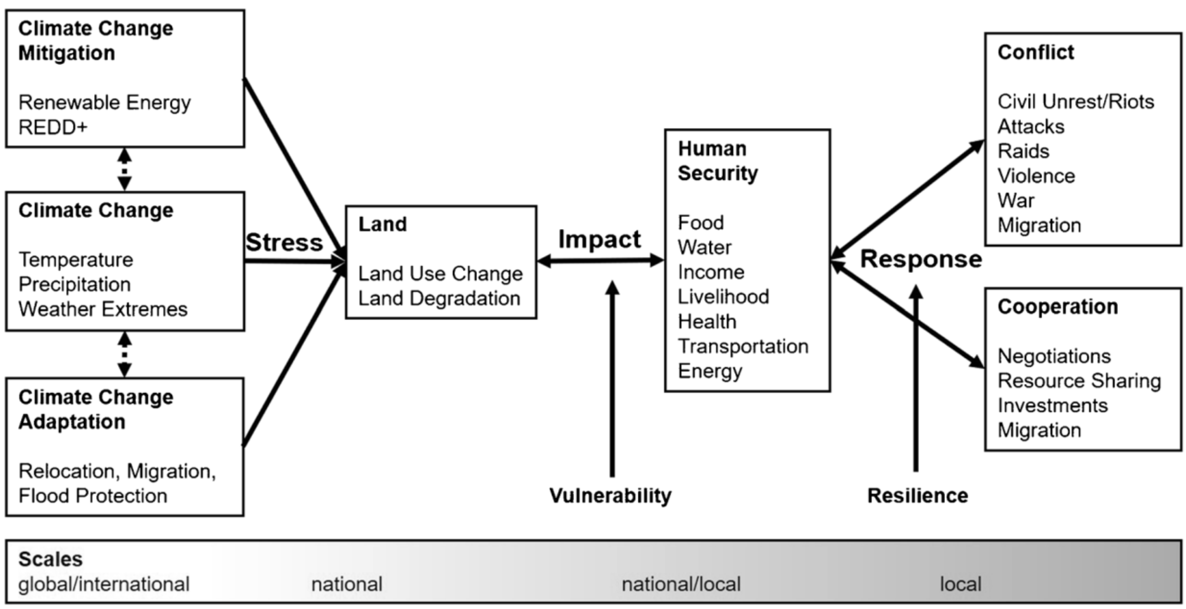


Figure 29: Conceptual framework of the effects of climate change on resource availability, conflict, and dynamics

Examples of local land use issues in both Australia and Japan in recent times include some of the following:

- Australia:
  - Network expansion.
    - Rural communities are galvanizing opposition against high voltage power lines, which are perceived to impact rural landscapes, farm values, land access, and potential tourism developments. [122]
  - Perceived inappropriate siting of projects.
    - More than 1,200 hectares will be cleared near the Tully Falls National Park, potentially threatening several vulnerable species in the area, along with severally impacting the areas visual amenity with 28 turbines, each more than 200 m high. [123]
  - Competing economic interests over access to land.
    - Farmers are concerned about a solar 'factory' on 566 hectares of premium agricultural land, potentially impacting food security and long-term sustainability of land use for generations to come. [124]
- Japan:
  - Perceived inappropriate siting of projects.
    - The Chiba prefecture, Kamogawa solar project, at 300 hectares, will require pristine forest to be cleared and is facing mounting opposition. [125]
  - Mega solar farm siting.
    - Local resident concerned landslides, environmental destruction, and electromagnetic waves from a Mega solar farm. In addition, the economic benefits are perceived to be for 'distant' city users with little local benefit. [126]
  - Social acceptance problems.
    - 80% of Japan's 47 prefectures have problems with solar power plants with visual amenity and environmental destruction the two largest issues. [127]

Summary and Conclusions

A series of modelling runs using the MEGS model have been undertaken for the Australian east coast electricity grid (the NEM) and Japanese electricity grid. More than 1,000 scenarios for each system were completed, all satisfying the system needs for 2050.

A wide range of technologies where able to be deployed during this analysis, including:

- Wind
- Solar PV
- Battery storage
- Hydrogen storage
- Coal CCS
- Gas CCS
- Biomass CCS (BECCS)
- Nuclear
- Unabated coal
- Unabated gas (combined and open cycle)

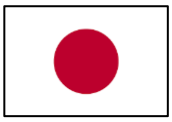
The modelling has demonstrated a clear lowest cost frontier, which as it approached net zero, became increasingly expensive. All efforts to reduce carbon emissions in a power grid of the future will come at an increased cost. Hence a major driver for managing this transition will be working towards the best outcome whilst keeping the cost increases as low as practicable. The work has also demonstrated clearly that renewables alone cannot be used to achieve net zero. A lowest cost solution without BECCS is very expensive.

Australia

The lowest cost solution for net zero for the Australian NEM in 2050 has about half of the energy being generated from renewables. The renewables are dominantly wind and solar PV. Approximately a quarter of the energy is being generated by firm, dispatchable, low carbon capacity such as nuclear, fossil fuel-based CCS and BECCS.

Delivering a 90% decarbonised grid in 2040 with a large renewable capacity, strong storage and interconnection and then doing a 'U-turn' by lifting any technology restrictions comes at a cost. Allowing the deployment of a range of technologies to get to net zero by 2050 raises the cost by $AUD 10/MWh compared to the lowest cost solution.

Japan



The lowest cost solution for net zero for the Japanese electricity grid in 2050 has about half of the energy being generated from firm low carbon capacity. Nuclear has a critical role, as does BECCS, being a critical carbon offset technology to enable net zero.

Hydrogen storage is very uneconomic under the current cost considerations.

Removing nuclear as a technology option increases the total system cost by $USD 10/MWh.

Remaining Questions

As with all research work, there remains questions worthy of consideration, or questions that the work now poses that were not evident earlier.

- Biomass and biomass in conjunction with CCS plays such a critical role in the decarbonisation process, therefore constraints, restrictions, costs, and other biomass assumptions should be tested in order to understand their impact on possible future scenarios.

- Given the importance of hydrogen in the Japanese decarbonisation strategy and energy diversification more broadly, further work ought to be done to explore the cost and availability of hydrogen, ammonia and other hydrogen storage options within the Japanese and Australian contexts.

- What are the constraints and costs of CCS for Japan, including understanding the opportunities for storage, including locations like Timor-Leste and Northern Australia.

- Understanding the cost and performance interplay between nuclear and CCS technologies and the role and importance of CCS flexibility.

- What are the sensitivities to costs of renewables for Japan, and what are the constraints on development, particularly for on and offshore wind.

- What are the upper limits for renewables in an Australian and Japanese context before cost and curtailment of energy become an evident detriment to the cost of the system.

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Appendix A – Data Sources

Data Specific to Australia

Most of the data for the Australian model comes from three key sources:

- NEM Review by Global Roam, a commercial data source for detailed half hourly data. Abbreviated as “NEM Review” below. [128]
- AEMO Integrated System Plan 2022, Assumptions Workbook 3.4 as the primary source. Where data varies by scenario “Step Change” has been used. If the required data exists here no other sources are used. Abbreviated as “ISP” below. [129]
- GenCost: Annual Electricity Cost Estimates for Australia by CSIRO. Used as the primary source for all CAPEC and OPEX data. Abbreviated as “GenCost” below. [130]

Demand

The ISP has expected demand for each state from 2022-2050, although it is published separately from the main assumptions workbook. Data was filtered by “ISP 2022” and “Step Change” and downloaded March 2022. Data for consumer demand (as used by MEGS) was generated by adding “Native” and “RooftopPV”. [131]

The shape of the demand across the year was taken from the half hourly demand data published for each region by NEM Review. For all shape data the average weather year 2015 was used.

Table 4: Modelled regions and their demand

Region	Code	2022 Energy (TWh)	2022 Peak (GW)	2050 Energy (TWh)	2050 Peak (GW)	Minimum Inertia (GWs)
Queensland	NSW	71.8	12.0	126.6	21.1	16.6
New South Wales	QLD	59.1	10.7	138.7	25.1	18.1
Victoria	SA	15.1	2.8	36.8	7.0	13.9
Tasmania	TAS	11.4	1.9	14.2	2.4	3.8
South Australia	SA	45.7	10.9	100.7	23.9	4.4
NEM	**NEM**	**203.1**	**32.5**	**417.0**	**66.7**	**56.8**

Reserve Requirement

Reserve (representing all frequency response and short-term reserve services) was taken as the sum of the half hourly Raise Requirement published by NEM Review for 6 seconds, 60 seconds and 5 minutes for 2015.

Minimum Inertia

Minimum inertia levels for each region are taken from AEMO’s 2022 Inertia report [104] and are shown in Table 6.

Current stations and plant under construction

The base generation capacities are taken from AEMO's "Generation information page" published in May 2023. A list was downloaded in July 2023 [132] of 1,357 entries. Capacities are aggregated by State and plant type for plant >= 1 MW and with the following status:

- Committed (including upgrade) with commissioning expected by end of the year being modelled.
- In Commissioning.
- In Service (including those with announced withdrawal after the year being modelled).

All other status like "Anticipated" and "Announced" were assumed to be too speculative to be definite, and anticipated closure dates (where there has been no announcement) are ignored as these can be brought forward or life extended.

Weather Data

The current weather dataset is from 2006 to 2020 inclusive and additional data sources include the DOE NCEP reanalysis data [133] to fill in some "holes" and places where Renewables Ninja give poor results. Reanalysis data from NCEP and Renewables Ninja [134] has been supplemented by actual performance from wind and solar plant as reported to NEM Review. [128] The data processing covered in more detail in paper. [68]

For MEGS this impacts the inputs:

- Wind profiles: If five or more wind farms exist within a state then onshore output profiles are entirely based on actual data. Otherwise, sparse actual data is supplemented by Renewables Ninja and NCEP data. The latter was also used to construct offshore wind profiles for SA, VIC, TAS and NSW.
- PV profiles: For 2006 to 2015 Renewable Ninja data was used, for 2016 onwards a mixture of Rooftop and solar farm data was used from NEM Review.
- Hydro: Existing NEM Review data used for 2006 - 2022.
- Demand and FCAS: Existing NEM Review data used for 2006 – 2022.

Commercial Parameters

Basic CAPEX data were taken from GenCost. Regional cost variations are small and ignored, except for additional transmission cost if the capacity of Renewable Energy Zones (REZ) is exceeded. The AEMO ISP gives costs and capacities of transmission links that would increase the export capability of REZ's which is only 25GW in total. It is assumed that all but the most expensive transmission upgrades (those costing <$1,000/kW) would contribute to the connection cost. This increases REZ hosting capacity across the NEM from by 55 to 80 GW at a typical cost of $500/kW. These connection costs are added to CAPEX based on average costs for the REZs in each region.

Table 5: Commercial parameters used in MEGS from GenCost including ISP connection costs ($AUD)

Costs in $AUD	CAPEX* $/kW	Fixed $/kW/year	Variable $/MWh	Comm. Life years	Fuel $/GJ
Utility PV (<25GW RE)	946	18	0	30	-
Utility PV with REZ upgrade	1291	18	0	30	-
Onshore wind (<25GW RE)	2028	26	0	25	-
Wind with REZ upgrade	2350	26	0	25	-
Offshore wind fixed					-
BECCS	18114	162	12.6	30	17.7
Nuclear	8952	200	5.3	40	3.4
Black Coal with CCS	8954	81	8.2	30	2.1
CCGT with CCS	3740	17	7.5	30	10.9
OCGT	1701	11	3.1	25	12.0
Existing coal	-	70	4.5	-	2.2
Existing CCGT	-	21	7.7	-	10.9
Pumped Storage (16h)	3103	17	7.5	40	-
Battery (4h)	409	17	0	25	-

Weighted Average Capital Cost (WACC)

The WACC is used as the discounting factor for annualising CAPEX. It is set at 9% in all of the modelling.

Merit Order

Without subsidy or an effective carbon price some low carbon plant would hardly run (CCS and biomass in particular) as unabated coal and gas would be cheaper. Hence, they would be totally ineffective. In reality, the plant wouldn't be built unless it was near the top of the merit order. This is achieved by an internal subsidy mechanism within MEGS. It does not change the cost of the fuel in the total system cost calculations, but ensures low carbon plant runs. The effective merit order is as follows, those in *italics* are subsidised, actual costs vary slightly from region to region and transmission costs may mean local sources are cheaper than a higher merit plant far away. MEGS has an algorithm to determine when storage charges and runs to minimise system operating costs, so this is not part of the Merit Order:

1. PV
2. Wind
3. Offshore Wind
4. Hydro
5. *Nuclear*
6. Biomass waste
7. *BECCS*
8. *Brown Coal CCS*
9. *Black Coal CCS*
10. Mine gas (small)
11. *Biomass (pellets)*
12. Brown Coal
13. Black Coal
14. CHP
15. CCGT
16. OCGT
17. Diesel ICEs

Grid Constraints

This modelling assumed there are no constraints within a state (although renewable energy schemes will face additional connection costs beyond a certain capacity in each State). However, the States are interconnected relatively weakly, most by less than 10% of peak demand, as shown in Figure 30. [38] These constraints are used by MEGS to limit flows of energy and transfers of reserve from state to state.

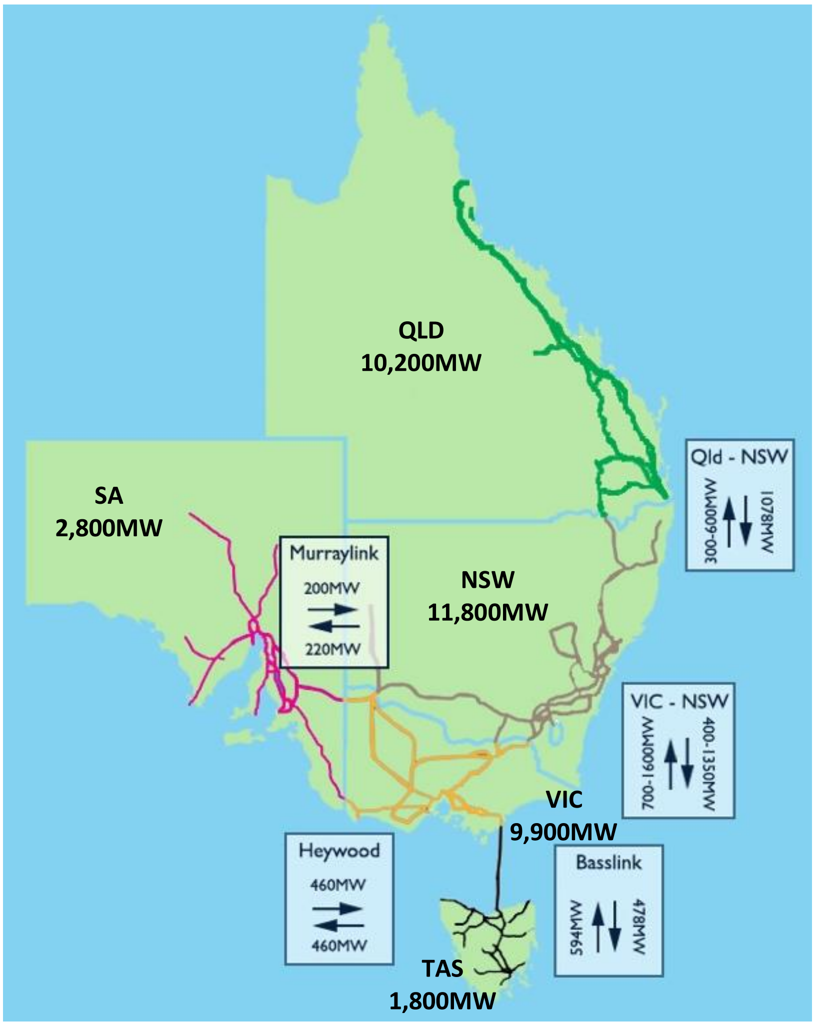


Figure 30 Australian National Electricity Market state interconnections and peak demands

Data Specific to Japan

The Japanese electricity system was modelled as nine interconnected regions (see Figure 31 [135]). Each region is an area controlled by a single TSO. This subdivision is well defined electrically and is commonly used in data sources.

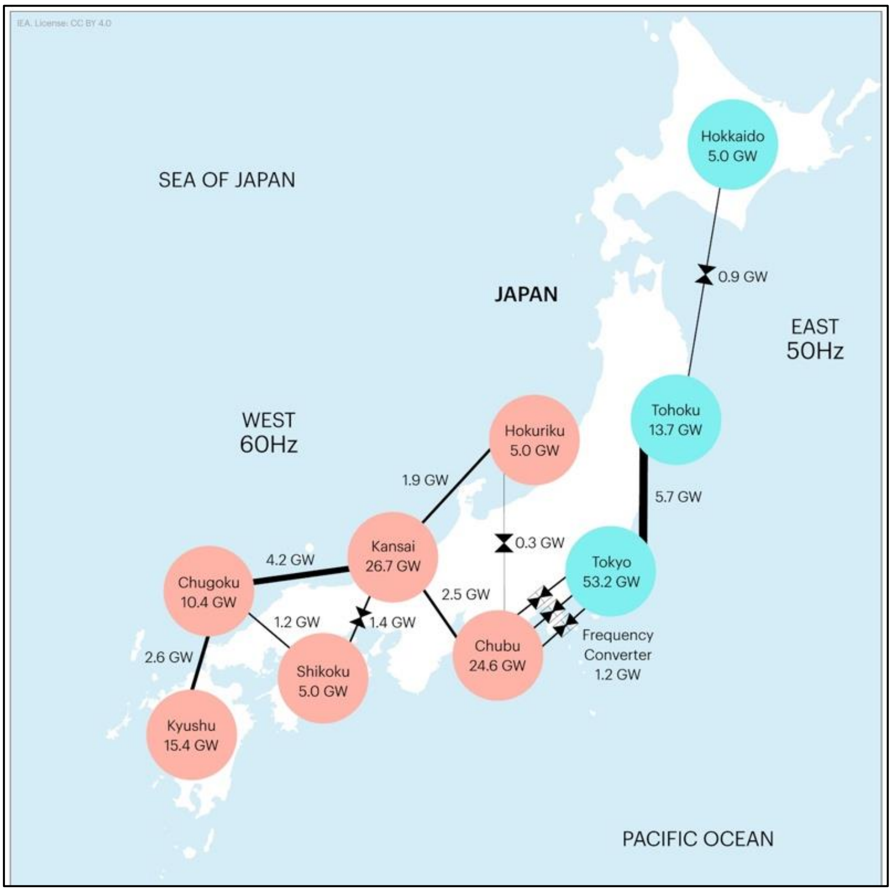


Figure 31 Map with overlaid schematic of regions used in the model and connection capacities

The modelling of Japan used a data from the calendar year of 2022 for all inputs affected by weather, i.e. demand and renewable generation. Much of the data was collated by Shulman Advisory GK, Tokyo from Japanese Ministry of Economic, Trade and Industry (METI) and various other sources. It is referenced here as 'Shulman'.

Demand

Demand data was provided by Shulman for the period April 2021 to September 2023 on an hourly basis for each region. The data for 2022 was used directly for the modelling of the year. All the data was used to create a de-weathered demand by averaging it by calendar month / hour of the day, by region. The storage algorithm uses this to forecast future use when determining how it should operate.

Shulman predicted the total Japan demand for electricity in the year 2050 to be 1,470 TWh. This was shared amongst the regions in proportion to their 2022 demand.

Table 6: Modelled regions and their demand

Region 50Hz / 60Hz	Code	2022 Energy (TWh)	2022 Peak (GW)	2050 Energy (TWh)	2050 Peak (GW)	Minimum Inertia (GWs)
Hokkaido	HKD	30	5.0	51	8.4	22.8
Tohoku	THK	83	15.0	139	25.1	27.5
Tokyo	TKO	286	59.3	477	99.0	33.9
Chubu	CHB	134	25.5	224	42.6	41.4
Hokuriku	HKR	29	5.5	49	9.2	36.2
Kansai	KNS	144	27.4	241	45.8	35.4
Shikoku	SKK	28	5.2	46	8.7	31.5
Chugoku	CGK	60	10.7	100	17.9	30.0
Kyushu	KYU	86	15.7	143	26.2	35.4
All grids		**880**	**165.0**	**1470**	**275.5**	**294**

Reserve Requirement

Reserve (representing all frequency response and short term reserve services) was set at 8% of demand. [136]

Minimum Inertia

Each region also needs to maintain a minimum level of inertia, so that if another power plant trips the rate of change of frequency that results (RoCoF) is kept to an acceptably low value. Sources [29] and [30] agree that ROCOF should be kept below 0.2Hz/s in Japan for the grid to be stable. However, the UK and other grids are moving towards a much faster standard of RoCoF up to 1.0 Hz/s, which greatly reduces the need for inertia, via the following equation.

minimum inertia = (lost generation * frequency) / (2 * maximum acceptable RoCoF).

Using this and the relevant frequency are largest potential loss in each region gives the minimum inertia levels found in Table 6.

Current stations

Oil, coal, gas, hydro and nuclear. Shulman provided current plants in operation. In addition, a news item on Japan-forward.com indicates that Kashiwazaki-Kariwa (in Niigata prefecture in Hokuriku) is restarting.

Solar and wind. Shulman provided solar and generation in each region in 2022. Solar Power Europe [137] reported installed solar capacity in Japan at the end of 2022 as 84.9GW . The Japan Wind Power Association gave the installed wind capacity in Japan at the end of 2022 as 4.8GW. [138] For each type, the total capacity was divided across the regions in proportion to their 2022 annual generation to produce the installed capacity of each region.

Pumped storage. The International Energy Agency states that 8% of Japan's 290 GW of installed capacity is pumped hydro. [135] This corroborates the stations list published by so capacities were taken from here.

Biomass and Waste. Shulman provided monthly generation by region in 2022 of both biomass and waste. Taking the month with the largest generation enabled a minimum installed capacity to be calculated. This was close to other references and is relatively small so taken as actual capacity in each region.

Geothermal and Diesel. The stations list published by has just 522MW of geothermal and 280 W of diesel identified by region so this was used. [138]

Weather Dependent Generation

Shulman provided generation data for each type of plant, by region.

Hydro. Shulman provided monthly generation for 2022 for each region, but this included pumped storage output as well. By assuming generation was spread between pumped storage and hydro in proportion to their capacities a reasonable estimate of hydro generation was obtained for each area. MEGS uses the assumed inflows to reschedule that generation within the day as required.

Solar. Shulman gave generation by region for each five-minute period, in MW, for 2022. This was averaged across the half-hours and divided by installed capacity to get capacity factor by half-hour by region. This is used in the renewables simulations, and in runtime data, to reflect the weather in 2022. Data for the period April 2021 to September 2023 inclusive was provided which allowed a more averaged capacity factor to be calculated, reflecting a slightly longer-term view of the weather.

Onshore Wind. Shulman provided generation in five-minute periods for Tohoku only, which was the only region with substantive amounts of wind at the time. So, the same process as for solar was used to give capacity factors for Tohoku, reflecting the weather for 2022, and also an average monthly view based on data from April 2021 to September 2023.

To obtain capacity factors for the other regions, windspeed data based on reanalysis of weather data was obtained from National Oceanic and Atmospheric Administration. [139] The windspeed data is based on a grid with 2.5 degrees resolution by latitude and longitude, four measurements per day for all of 2022. A point as close as possible to the centre of each region was chosen. By comparing actual data from Tohoku with the reanalysis data from above a relationship between the reanalysis derived wind and actual power output could be derived (Figure 32). This power curve was then used to characterise generation in other regions based on the reanalysis wind speed. As with other weather dependent parameters data from April 2021 to September 2023 was used to calculate monthly averages.

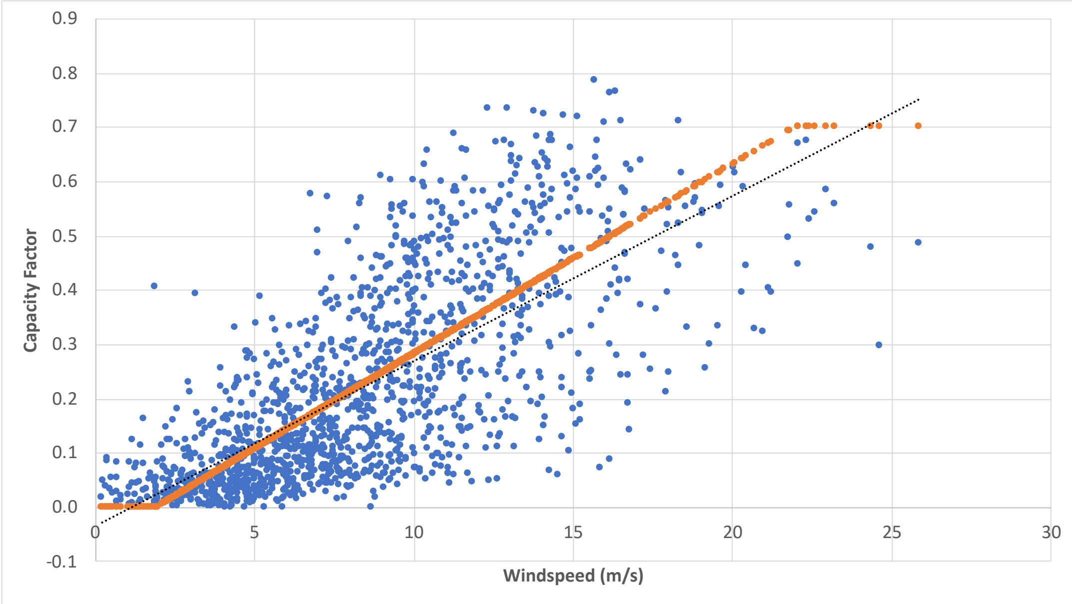


Figure 32: Capacity factor as a function of wind speed for Tohoku (blue), and derived power curve (red)

Offshore wind. It was assumed that the average capacity factor would be 40%. Therefore, the windspeeds calculated as for onshore above were scaled upwards, until the calculated capacity factor, averaged across the nine regions, became 40%. The resultant multiplier to the onshore winds was 1.9.

Commercial Parameters

All costs quoted were converted to $USD at the prevailing exchange rate. Lazard's LCOE+ report [140] was used for various aspects of commercial data, The LCOE calculations were ignored but the Appendices contained the input data as summarised in Table 7.

Table 7: Commercial parameters in $USD used in MEGS from Lazard, Drax in blue, Australian experience in green

Costs in $USD	CAPEX* $/kW	Fixed $/kW/year	Variable $/MWh	Comm. Life years	Fuel $/GJ
Solar (Utility PV)	883	10.5	0	30	-
Onshore wind	1,248	27.5	0	20	-
Offshore wind fixed	3,672	70.00	0	20	-
BECCS	5,953	94.85	5.46	40	9.26
Nuclear	11,200	142.12	4.62	40	0.78
Coal with CCS	5,953	94.85	5.46	40	2.17
CCGT with CCS	2,136	20.31	4.95	20	4.88
OCGT	869	12.00	0	20	4.88
Existing nuclear	-	108.62	3.30	-	0.78
Existing coal	-	24.75	4.12	-	2.17
Existing CCGT	-	11.62	1.50	-	4.88
Existing Geothermal	-	14.62	16.38	-	-
H_2 15 day storage, electrolyser & turbine	20,009	33.03	0	25	-
Battery (4h)	979	11.45	0	20	-

** Average over build period to 2050 using Gencost learning rates*

CAPEX. Cost of build of new power plant, in $USD per kW, were given in Lazard for 2023, this study took the average of the low and high case as a starting point. These were combined with learning rates used by Gencost [130] and averaged over the build period prior to 2050. The CAPEX for biomass and BECCS was assumed to be the same as a black coal plant.

Hydrogen storage CAPEX. Lazard above gave the cost of the electrolyser which was assumed to be for alkaline and reduced by this learning rate over time. The turbine cost is set to the same as an OCGT plant. The storage is assumed for 15 days, using hydrogen pipes, costed at 500 €/kg of hydrogen in 2023, decreasing to 250 €/kg in 2050, [141] this is the dominant cost.

OPEX. Lazard above provided fixed and variable operating costs for a number of power plant types. Australian costs were used, converted to $USD, where Lazard had no data. For the hydrogen electrolyser, Lazard had OPEX as 1.5% of CAPEX and this was taken as a fixed cost.

Non-fuel start-up costs (not shown in table) were converted from $AUD into $USD.

Fuel. Taken from Lazard except where unavailable. Oil cost, based on [27], [142] biomass and diesel were converted from Australian figures. Wood pellets based on published Drax data [143, 144] which equates to £75/MWh.

CO_2 Storage. Lazard gave a CO_2 transportation and storage cost of $USD 23/tonne.

Weighted Average Capital Cost

The WACC is used as the discounting factor for annualising CAPEX. It is set at 9% in all of the modelling.

Merit Order

This is the order in which short run marginal costs are set, *italics* giving where a subsidy was required in MEGS to ensure low carbon plant runs ahead of high emissions plant. Otherwise, there would be no point building the plant. In reality, this might come directly or via a future carbon price.

1. PV
2. Wind
3. Offshore Wind
4. Hydro
5. Nuclear
6. Biomass waste
7. *BECCS*
8. *Black Coal CCS*
9. *Gas (CCGT) with CCS*
10. *Biomass (pellets)*
11. Black Coal
12. CCGT
13. OCGT
14. Diesel ICE

Grid Constraints

There are no constraints within each of the nine grid regions which act like “copper plates”. Shulman provided a list of connectors between regions and their transmission capacity each way. The source was OCCTO. [145] Figure 31 above shows how they were interconnected and emphasises the weakness of the connections compared to the demand in each region.

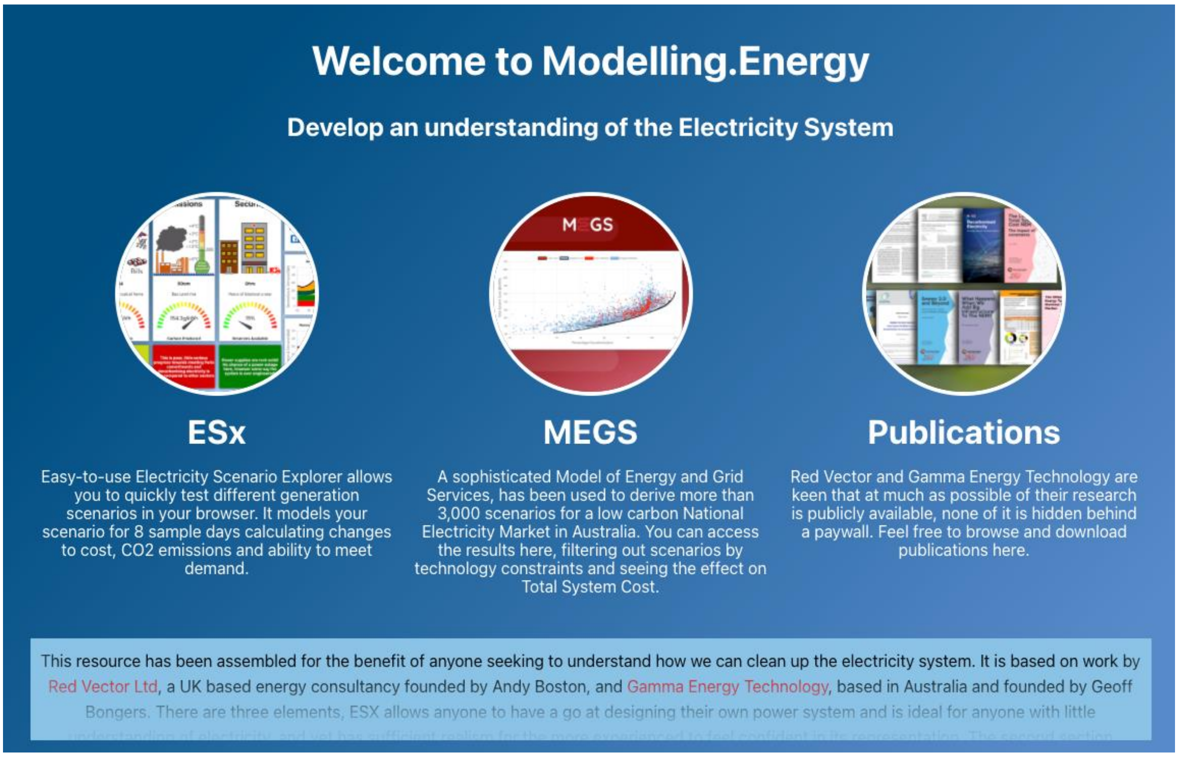
Appendix B – Glossary

AEMO	Australian Energy Market Operator
AUD	Australian Dollar
bcm	Billion Cubic Metre (unit of gas)
BECCS	Bio Energy with Carbon Capture and Storage
CAPEX	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DOE	Department of Energy
EIA	U.S. Energy Information Administration
EPRI	Electric Power Research Institute
ESO	Electricity Systems Optimisation
FCAS	Frequency Control Ancillary Services
HHV	Higher Heating Value
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
ISP	Integrated System Plan
LACE	Levelised Avoided Cost of Electricity
LCOE	Levelised Cost of Energy
LNG	Liquified Natural Gas
MEGS	Modelling Energy and Grid Services (modelling optimisation tool)
METI	Ministry of Economic, Trade and Industry
MTce	Million Tonnes of coal equivalent (unit of coal)
NCEP	National Centers for Environmental Prediction
NEM	(Australian) National Electricity Market
NETL	National Energy Technology Laboratory
NREL	National Renewable Energy Laboratory
OCCTO	Organization for Cross-regional Coordination of Transmission Operators
OCGT	Open Cycle Gas Turbine
OPEX	Operational Expenditure
PV	Photovoltaic
REZ	Renewable Energy Zones
ROCOF	Rate Of Change Of Frequency (of the grid)
TSC	Total System Cost
TSO	Transmission System Operator
USD	United States Dollar
VAr	Volt-Amps Reactive
WACC	Weighted Average Capital Cost

Modelling Energy Website

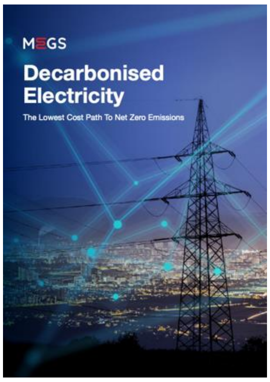
The authors of this report have also developed a website to allow readers to explore total system cost. By visiting https://modelling.energy/ readers can model the NEM and UK grids for both 2024 and 2050, with their own generation makeup. The website has been developed for both the public as an educational tool, as well as a detailed breakdown for those who require additional information.

The website has been designed with the purpose of demonstrating some of the basic principles of good electricity system modelling, in a fun environment that should bring out broad brush principles. Though it is not intended as a tool for detailed analysis or system planning, if understood well, it is sufficiently robust to enable a user to ask the right questions about decarbonisation and to better interrogate results from other models advocated in the electricity system literature.



Additional Reports

https://modelling.energy/#publications

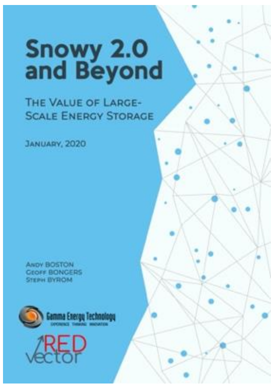


Decarbonised Electricity. The Lowest Cost Path to Net Zero Emissions

The purpose of this book is to clear the air on key aspects of grid technology assessment and give some insight into what a future grid may look like. This is not an easy task, as comparisons of the cost and value of electricity generation resources for the NEM have become increasingly complex. Changes in the market's mix of generation, plus the public and political focus on the need to maintain a fit-for purpose system, mean that cost comparison metrics used in the past have become less useful today.

The Lowest Total System Cost NEM: The Impact of Constraints

This study highlights the need for firm zero-carbon dispatchable generation to support the NEM. It also clearly shows that a net-zero grid will be much more expensive, the total system of today's grid is ~$AUD 11Bn/y – this will TRIPLE by 2050 with very deep decarbonisation. Restricting VRE, CCS or nuclear has a mostly modest impacts, but no CCS means a ~$AUD 5Bn/y impact. Excluding both CCS and nuclear results in a very large increase in TSC at 99% decarbonisation.



Snowy 2.0 and Beyond: The Value of Large-Scale Energy Storage

This study has examined the impact of Snowy 2.0 and the Battery of The Nation, as well as scenarios beyond these two projects, to examine what benefit large scale pumped hydro storage could provide to the NEM as it decarbonises. In line with previous studies, the analysis undertaken focuses on total system cost (TSC) and CO_2 emission reductions as the key metrics. Decarbonisation is assumed to be the objective and TSC optimised, as this is what the consumer will ultimately have to fund.

IEA Greenhouse Gas R&D Programme

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