Submission to CSIRO's Draft 2024-25 GenCost Report

By Independent Engineers, Scientists and Professionals, 11 February 2025

Aim

This submission to CSIRO/AEMO regarding the draft 2024-25 GenCost report by independent engineers, scientists and professionals (IESP) is made with the objective of providing useful feedback and insight into the true costs of implementing the government's Net Zero 2050 policy for the National Electricity Market (NEM).

Professor Michael Asten, PhD, BSc (Hon), BLitt, FRAS
Ben Beattie, BE(Elec), CPEng RPEQ
Jeremy Barlow, BE, MBA, FAIMM
William Bourke, BSc, BEng (Aero), MEng Sc.
Michael Bowden IEng (Electronics-UK); CPL; CQP
Rafe Champion, MSc (History and Philosophy of Science), B.Ag.Sc. (Hons)
Arthur Day, PhD, BSc (Hon)
Paul R C Goard, BSc, Physicist, M.A.I.P., M.I.of P., M.A.I.E., M.A.M.O.S.
Peter J F Harris, BEng, Dipl. Prod Eng.
Professor Emeritus Aynsley Kellow, BA(Hons) PhD
Bryan Leyland, MSc (Power systems) DistFEngNZ, FIMechE, FIEE (rtd)
John McBratney, B. Tech (Electronic Engineering), formerly MIE Aust, MIEEE
John McLean, PhD
Paul Miskelly, BE MEngSc Electrical Engineering
Grant Piper, BE Aero UNSW, FRAeS, Chair NREN
Peter Ridd, PhD, BSc
James R (Jim) Simpson, (Ret., former business unit manager, OTC & Telstra)
Bill Stinson, Dip.Tech(Building), B.AppSc.(Building), Dip Labour Relations & Law, Cert. Design Sc. (Facilities)
James Taylor, PhD, MSc, BEng Elect (Hon), PEng, FCASI

Corresponding Author: james.taylor861@gmail.com

Conclusions and Recommendations

Independent Engineers, Scientists and Professionals, 11 February 2025

1. GenCost fails to demonstrate that it is 'Australia's most comprehensive' report on NEM costs. It fails to include major cost elements funded by government and consumers. Its levelised cost of electricity (LCOE) method is aimed at providing investors with theoretical marginal investment indicators limited to investor costs, not national electricity costs, yet undisputedly this document is misused by government to justify its energy policies. GenCost should be much more forthright upfront in the disclaimer and executive summary regarding its true purpose.
2. GenCost's claim that wind and solar are the cheapest form of electricity generation are completely contradicted by whole-of-system ISP capital cost cash flow estimation – by a large margin as indicated in Appendix 2 to this submission and other reports. CSIRO needs to explain the reasons for this stark difference or clearly state that it is geared to investor interests and is not fit for purpose to underpin national energy policy. The warning on page 57 states that cash flow cost models are more realistic but is not sufficiently prominent.
3. GenCost employs highly contestable assumptions and data concerning capacity factors, capital cost factors, facility lifetimes and spillage costs. CSIRO should rebalance the assumptions and data for consistency to ensure it does not unduly favour renewables.
4. GenCost fails to account for Consumer Energy Resources (CER), low voltage distribution network upgrades and disposal/remediation costs, which form a very large part of whole-of-system costs. CER by itself is 60% of all solar and battery capacities in AEMO's ISP. GenCost must include these costs – they are not free. A purposeful report should include all costs to the national economy, regardless of who pays.
5. GenCost's assumption that investors will have free access to previously built network resources is completely unrealistic in normal markets and particularly considering that grid design must be based on worst-case conditions, when all resources are at maximum utilisation. CSIRO must reconsider the whole GenCost approach to renewable integration costs.
6. GenCost's use of an unspecified electricity system model running 9 years of historical weather-related data to determine maximum integration costs based on the simple assumption that the grid will be reliable is a major mistake for many reasons.
    a. The 2011-2019 AEMO data does not encompass all worst-case conditions, which recent freely available data from both Australia and overseas indicate. Wind droughts and solar outages are a common-mode failure affecting the entire NEM.
    b. AEMO's use of a simulation model in the Integrated System Plan (ISP) illustrates the pitfalls, which are detailed in Appendix 1. CSIRO must provide details of the model used and how the criteria for reliability must include maintaining a viable dispatchable reserve margin under all conditions to protect against facility outages. The failure of the ISP to define worst-case conditions inherent to proper high reliability system engineering casts serious doubt on the integrity of its modelling and grid design with direct implications for GenCost.
7. Both GenCost and the ISP are important documents having major influence on energy policy with impacts on the entire economy and the security of all Australians. The criticality of the NEM to the well-being of the entire nation deserves rigorous and independent accountability by the same type of certification authority used in other fields such as aviation, transportation, telecommunications, civil works and the financial industry. CSIRO should support the establishment of a proper independent regulatory body to review, hold accountable and certify plans and implementation of the NEM.

Table of Contents

Introduction

Reliable and affordable electricity is essential for the nation's economy and in some cases to individuals who are medically dependent on it. It is the linchpin to national productivity. National security demands reliable power. Virtually all jobs depend on it. It is vital therefore that any changes to the NEM ensure that reliable and affordable electricity continue to be available in abundance.

There is increasing disquiet in the community about rising electricity costs and the impacts that renewables impose on the environment. There is more disquiet in the United Kingdom and Germany where renewables are having greater impacts, but it appears these lessons are being ignored.

The scientific community is beginning to acknowledge that the climate impacts of CO_2 emissions have been overstated and overhyped by media. The futility of reducing Australia's emissions in the face of overwhelming global emissions growth in major countries such as China, India and the US and all developing nations, is also contributing to a trend in declining public support.

Political and media dialogue is now focused on real concerns about future prosperity in an economy that is facing both energy shortages and massive cost rises. Jobs and businesses are on the line. We are already seeing instances where high energy costs are major factors in business closures.

There is an urgent need for full and forthright information. GenCost states that it a collaboration between CSIRO and AEMO[1]. Its Executive Summary claims it to be "*Australia's most comprehensive electricity generation cost projection report*." It is not. This submission identifies multiple serious failings with CSRIO's GenCost report and, given that AEMO's ISP is closely related, failings in the ISP too.

There are many. It is now time for CSIRO to have the wisdom from introspection and the courage to speak truth to power and to the public.

Detailed Assessments

As concerned citizens with deep backgrounds in engineering, science and business management, we present the following assessments to illuminate the shortcomings of the CSIRO 2024-25 GenCost Report. This work upgrades our previous submissions to AEMO on the 2022 and 2024 draft ISPs, AEMO's Inputs, Assumptions and Scenarios (IAS) consultation (August 2024) and the Senate Select Committee on Energy Planning and Regulation (October 2024).

Our concerns, together with those of many other highly qualified experts and organisations, focuses on reliability and costs; flashpoints that can no longer be dismissed or ignored.

1.0 Flawed Methodology

According to GenCost[2], "*The stated purpose of GenCost is to provide essential capital cost information for the modelling community to use in their own system cost studies.*" While the capital cost data, despite some contestable issues, is useful for user studies (we use it in our whole-of-system modelling), we consider the LCOE results to be controversial and not indicative of real-world costs.

The GenCost report starts with an 'Important Disclaimer' which states in part: "*The reader is advised and needs to be aware that such information may be incomplete or unable to be used in any specific situation.*" Presumably, this disclaimer is made for legal reasons but it also shows a lack of confidence.

[1] GenCost Executive Summary Pviii

[2] GenCost Section D.4.16 P108

GenCost also states[3] that: *Modelling studies such as AEMO's Integrated System Plan do not require or use LCOE data. LCOE is a simple screening tool for quickly determining the relative competitiveness of electricity generation technologies. It is not a substitute for detailed project cashflow analysis or electricity system modelling which both provide more realistic representations of electricity generation project operational costs and performance."* Despite this warning, GenCost makes definitive conclusions regarding the cost of firmed solar and wind[4] being the lowest cost.

It is unfortunate that government ministers and managers do not make time to read such details. The ideological commitment to so-called renewables appears foundational. It is incontrovertible from ministerial statements that government energy policy is based on the stated assertion that *firmed wind and solar are the cheapest form of electricity generation as shown by CSIRO's GenCost reports*.

Our whole-of-system cost assessments in previous submissions, based on cashflow modelling as suggested by GenCost is more realistic, demonstrate that this assertion is incorrect. LCOE outputs shown in GenCost, even when modified by estimated (2030) integration costs, indicate exactly the opposite of whole-of-system capital cash flow modelling.

It is apparent that the basic LCOE methodology in GenCost is aimed at providing theoretical marginal investment indicators rather than total system costs[5]. They are two different things yet GenCost is hailed by government ministers as the authority to dictate the design of the national power grid through regulations thus bypassing qualified power systems engineers.

This difference in methodology urgently needs reconciliation to avoid misleading information from continuing to adversely affect national energy policy.

2.0 Cost Modelling Accuracy

Our assessments conclude that the AEMO 2024 ISP Step Change scenario does not represent a viable grid design for delivering reliable electricity because its proposed storage facilities and baseload generation capacities are grossly insufficient under worst-case conditions and very expensive.

Appendix 1 to this submission is a top-level modelling analysis of grid reliability, which was submitted to AEMO last August as part of the IAS consultation process. For this submission, it is updated with the subsequent release of AEMO's 2024 Electricity Statement of Opportunities (ESOO), which contains significantly reduced forecasts for future peak power demands in the Step Change scenario and reductions in annual energy delivery.

Our top-level capital cost analysis in Appendix 2, which was also provided to the IAS consultation, is based on whole-of-system modelling using generation and storage capacities from AEMO's 2024 ISP and capital cost factors from the draft 2024-25 GenCost. That analysis is more comprehensive because it takes into account facility lifetimes and estimates for transmission extensions, distribution infrastructure upgrades, grid stabilisation and disposal.

It is important to understand accuracy versus fidelity in all modelling.

- Accuracy is how well the analysis results predict future reality.
- Fidelity is the degree of detail embraced by the model.

Higher fidelity does not necessarily lead to more accuracy, <u>especially when input data and assumptions contain great uncertainties</u>.

[3] GenCost Section 6.1 P57
[4] GenCost Executive Summary Pxi and Figure 0-2 Pxii
[5] GenCost Section 2.1.4 P20

We understand that predicting future costs over 25 years is extremely difficult. Changing situations can lead to errors of hundreds of percent (e.g. Snowy 2.0). GenCost acknowledges uncertainties in costings but does not quantify all of the impacts to their LCOE outputs.

GenCost's capital cost factors for generation and storage technologies are estimated by referencing multiple papers and sources, all of which suffer significant uncertainties. ISP capacity models are based on predictive modelling of electricity demand, weather impacts and social licence for CER availability among many variables, all of which contribute considerable uncertainties.

We argue that past experience shows it is prudent to assume that all cost models will exhibit indicative uncertainties of at least 30-50% and in some cases considerably more. Nevertheless, we suggest that using a simple top-level whole-of-system model is adequate to assess 25-year cost estimates since the uncertainties of the input data used by all models over a 25-year period dominates the accuracy of results, regardless of modelling fidelity.

When used in a comparative manner to assess various design options, most models can be expected to provide somewhat improved 'relative accuracy'.

3.0 Capital Cost Factors

GenCost defines future capital cost factors[6] for various generation and storage technologies. It observes recent years when freight and raw materials rapidly increased costs. Its use of a 2006 to 2009 price bubble to show prices returned to previous expectations is not entirely realistic since the industry was much smaller at that time and basic power costs affecting manufacturing have been recently escalating much more rapidly.

GenCost's contention that "…*inflationary pressures for most technologies and the cost of some…such as solar PV and batteries are falling again*" is contestable. We believe this is only a small part of the story.

In our view:

- Renewables are now relatively mature technologies after 30 years of intensive development, thus making assumptions of substantial future cost decreases too optimistic.
- Labour costs have been hit with high inflation recently; these costs are not going to go down.
- The dominance of one country, China, in the entire supply chain for renewables makes higher future prices likely as competition is stifled and hence deserves more careful analysis.
- Increasing demand in global markets may cause price rises.
- Shipping costs are being hit by increasing fuel costs.
- Operating costs of renewables are greater than anticipated, as the UK and Germany have found.
- Subsidies for the cheapest form of electricity generation, which surely should not still be necessary) could be reduced, adding to manufacturing costs.

Compounding the uncertainties in predicting future costs are:

a. realisation that the extraordinary costs involved are not affordable nor sustainable,
b. the negative impact on national economies from unreliable intermittent power,
c. many countries, including the largest, doing nothing or very little, to meet Net Zero goals,
d. the withdrawal of the US from the Paris Accord,
e. the mounting market failure of EVs,
f. recognition that the science of climate catastrophism is overstated and overhyped, and
g. the severe environmental impacts of solar and wind generation installations being regarded as unacceptable.

[6] GenCost Section 5 P35

The ability to estimate the impacts of these factors is almost impossible, further reinforcing the substantial uncertainties in all future forecasting.

In our analysis, we bracket future costs by using both better known CSIRO 2024 cost factors flatlined across the next 25 years and CSIRO's optimistic capital cost factor projections. The difference in real total whole-of-system cost estimates (Appendix 2) for the 2024 ISP baseline is about 40%.

4.0 2024 ISP Cost Estimates

The AEMO 2024 ISP provides whole-of-system capacities and recommends the Step Change scenario, but does a very poor job at estimating whole-of-system capital costs. Its $122 Billion "*present value*" estimate is not based on real cash flow costs, which the public understands. Its discounted cash flow methodology, by 7% per year, amounts to about a 40-50% reduction from real cash flow costs. On top of that several major cost elements have been ignored.

The ISP explicitly excludes very large costs[7] for "..*commissioned, committed or anticipated projects, consumer energy resources (CER), or distribution network upgrades*". All of these costs are impacts on the economy and must be borne by taxpayers and consumers. There is no justification for ignoring these major costs and past 'sunk' costs for proper comparison of various grid design options. Evaluation of such a major transition to the mission-critical NEM must be done on a whole-of-system cost basis, particularly for comparison with alternative options.

It might be argued CER costs are borne by individual home-owners so they do not contribute to power bills but they are real costs that home-owners pay to obtain the electricity they require. Residential capacities for solar and battery in the ISP are each 60% of all solar and battery capacities respectively. They constitute the largest fraction of the total transition cost, particularly since home batteries are more than double the unit cost of utility scale batteries[8]. Amortised over expected lifetimes respectively of 20 years and 10 years respectively, solar panels and batteries can easily double the home-owner's total energy bill.

The non-inclusion of commissioned, committed and anticipated projects in the ISP refers to transmission grid projects. The apparent ISP write-off of these so-called "*sunk*" costs is completely unjustified for proper disclosure and comparison of alternative options because transmission lines needed for renewables are largely unnecessary for alternative grid designs.

The cost of required upgrades to local low voltage distribution networks to accommodate CER is ignored by the ISP. Without these upgrades, local voltage instability risks exceeding network standards causing untold damage to appliances and equipment in homes and businesses. Despite the AEMO 2024 draft ISP promising to address these costs in the final ISP, it simply states: *"The ISP assumes upgrades and other investments needed to enable distribution networks and their operation will occur through other mechanisms…."* [9]

The failure to consider these costs distorts the GenCost analysis.

The evident failure to consider all costs in the ISP does a great disservice to the country and the public. The public deserves to know the real total costs involved in the transition of the NEM to renewables and its proper comparison with alternative options.

---

[7] 2024 ISP Section 7.1 P74 footnote 33

[8] GenCost Section 5.3.13 P51

[9] 2024 ISP Executive Summary (P8)

5.0 Integration Cost Estimates

The conceptual approach embodied in GenCost is to calculate investment costs in individual technologies. It recognizes that intermittent and variable renewable energy (VRE) make grid reliability impossible without support from other resources, either baseload generation and/or storage[10].

The complex modelling techniques are described in general terms but lack enough detail to make detailed conclusions. The following subsections provide comments on particular issues.

5.1 Ensuring System Reliability

GenCost states[11] that "*An electricity system model is applied to determine the optimal investment to support each VRE share*" and "*We incorporate the uncertainty in variable renewable production by modelling nine different weather years, 2011 to 2019*".

It further states[12] that "..*costs of VRE share scenarios were compared against the same counterfactual weather year to determine the additional integration costs of achieving higher VRE shares*" and "..*We use the maximum cost across all (nine) weather years as the resulting integration cost on the basis that* ***the maximum cost represents a system that has been planned to be reliable across the worst outcomes from weather variation***." We hold serious reservations about the validity of this process.

Since GenCost is a collaborative project between CSIRO and AEMO, it is possible that the electricity system model referred to is AEMO's model and that running simulations of the model across nine historical years (2011-2019) is the basis of this analysis. This approach is highly problematic regarding the assumption of reliability due to the following facts:

1. IESP has made multiple submissions to AEMO and the Senate Select Committee on Energy Planning and Regulation that demonstrate the ISP fails to show that the grid design is reliable. See Appendix 1 for details.
2. The nine historical years do not necessarily encompass worst-case conditions as data from 2010 and more recent years, and from overseas locations, demonstrate. Wind droughts coincident with regular solar outages during about 16 hours every day across the entire NEM and substantial solar reductions due to daytime clouds constitute a frequent common-mode failure over lengthy periods affecting the entire grid. Extra transmission lines cannot distribute power that does not exist; storages are too expensive and the ISP is grossly under-equipped.
3. The ISP's "*exploratory*"[13] use of an electricity simulation model[14] allegedly demonstrating reliability of the design in an eight-day period of VRE drought is fraught with unrealistic assumptions:
   a. Reduced **VRE outputs due to weather were *not worst-case conditions*** *for the simulation*. The 2024 ISP actually states[15] "..*future weather may not replicate the past, especially with climate change, so there may be longer and more widespread renewable droughts*."
   b. Past **profiles of VRE production *cannot be assumed* to adequately represent future VRE production** due to major differences in geographic sitings.
   c. The daily demand profile[16] showing ***a drop in consumption overnight by about 30% is highly contestable***. Future demands for overnight EV charging were predicted in the 2023 ISP as

[10] GenCost Section 6.2.1 P58 and Section 6.2.2 P60
[11] Section 6.22 P60
[12] Section 6.6.2 P62
[13] 2024 ISP Appendix 4 NEM resilience through prolonged VRE droughts P25
[14] 2024 ISP Section 6.5 Reliability and security in a system dominated by renewables Figure 24 P72
[15] 2024 ISP Section 6.5 System reliable during peak demand and renewable droughts P72
[16] 2024 ISP Appendix 4 Section A4.2 The NEM's demand profiles will continue to evolve P13

having a flattening effect. Growing demands for data centres and other businesses needing 24-hour reliable power will also flatten overnight demand.

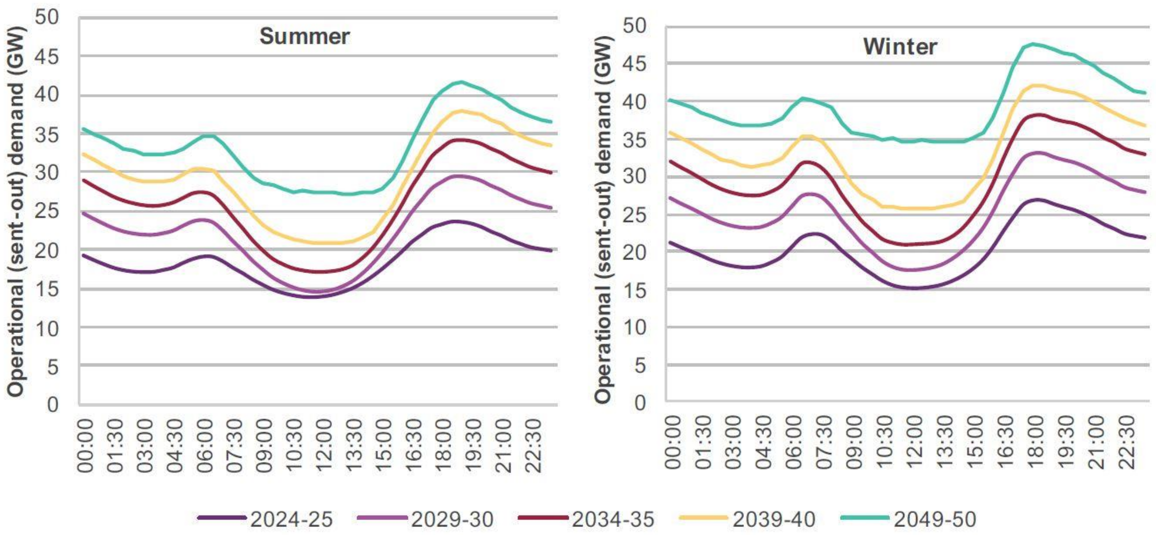
d. The ISP admits that the simulations assumed "..*NEM is projected to operate all available dispatchable resources (predominantly deep storages and gas*)"[17], thus making **no allowance for a dispatchable reserve margin (DRM) to guard against facility outages**, which we have advocated should be at least 20%. Our Reliability Assessment (Appendix 1) indicates that 2030 DRM in worst-case conditions of no solar and wind power will be minus 16% at night and as much as minus 30% in daytime, a guarantee of blackouts. In fact, it also states[18] "**In this simulated test of extreme weather resilience, no USE (unserved energy) was forecast, although any additional unplanned outages beyond those modelled may cause reliability concerns**."

This simulation approach is not proper system engineering design; it is an inappropriate illustration. DRM is the primary design parameter which determines reliability. This is underpinned by the fact that 2024 DRM under worst-case of no VRE was just 6%, down from 20% in 2019. The fact that AEMO was required on multiple occasions to issue public (Lack of Reserve) warnings of power shortages is testimony to this reality. The fact that NSW and VIC governments have been forced to strike secret deals with coal generators to keep them operating well beyond their planned (forced) shutdowns is further reinforcement. The 2024 ISP grid design is simply not fit for purpose.

Figure 3 from the 2024 ISP Appendix 4 below illustrates the assumed daily profile projected into the future. By 2050, the peaks in early evening fall about 22% by early morning compared to about 30% currently.

ISP Appendix 4 speculates[19] that "**The daily demand profile is forecast to change significantly by 2039-40, as a result of growth in**.." EV charging (which it suggests may be shifted to midday by time of use tariffs just when most people are likely to be needing their EV), electrification of home gas appliances, distributed PV system uptake and potential hydrogen production (and data centre demands). A great deal of uncertainty remains regarding future daily demand patterns, yet AEMO modelling incorporates this profile into its simulations of future grid performance.

Figure 3 Operational sent-out demand average time-of-day forecasts, summer and winter, *Step Change*, 2024-25 to 2049-50 (GW)



[17] 2024 ISP Appendix 4 NEM resilience through prolonged VRE droughts P25
[18] 2024 ISP Appendix 4 A4.5 Operating the power system during long, dark and still conditions P28
[19] 2024 ISP Appendix A4 A4.2 The NEM's demand profiles will continue to evolve P11

In the case of the daily demand profile, the best and most conservative approach is to assume a constant demand at peak, which we use in our analyses. Anything else would require a detailed analysis demonstrating a very high probability that the future demand profile will not exceed a given profile, and which would need a significant built-in safety margin.

The occurrence of severe VRE droughts is not as rare as the ISP states[20] "**The timing, severity and duration of prolonged dark and still weather conditions over a wide area are difficult to forecast, and indications are that these events are very rare**." Consider the incontestable fact that solar falls to zero every single overnight period from about 4 pm to 8 am the following morning. Adding more solar farms is no solution when there is no sun, yet it is frequently advocated!

Then consider historical wind conditions using AEMO's own data. Wind power over the entire NEM varies rapidly from zero to far above average at all times of day and night. The data across the whole east coast shows it frequently remains at zero (or very low) for periods from a few hours to several days. When NEM wind droughts occur during the 16 hours of zero solar power every day, VRE is zero or very close to it – these events happen frequently and are worst-case conditions. In addition, there are seasonal effects in weather patterns which can reduce solar and wind power well below average for months.

With so little storage (and insufficient resources to recharge it) and dispatchable generation in the ISP, **blackouts are a certainty**.

A fundamental shortcoming in the ISP appears to be lack of a clearcut definition of worst-case conditions to drive grid design for achieving reliability. The ISP design lacks necessary rigour, appearing to based more on hope and optimism than hard facts. Basing GenCost VRE integration costs on AEMO's inadequate model risks underestimation by a large amount.

5.2 Proper High Reliability System Design

IESP's submissions on reliability conclude the ISP shows little understanding of high reliability system engineering practice (a conclusion AEMO denies) and that this reflects poorly into the GenCost report. A key design principle is absolutely critical:

> A high-reliability system design must be based on worst-case conditions and then incorporate a margin of safety on top to guard against possible degradation of system capabilities.

Lives depend on getting engineering designs for high reliability right, whether it is a jetliner, a bridge, a building or a power grid. There are massive consequences for reliability failure.

The commercial aviation sector is particularly instructive. Hard lessons learned over decades have made it one of the most reliable transportation systems, governed by independent regulatory certification bodies. Two examples are worth noting:

1. A jetliner is loaded with enough fuel to make it to its destination even when encountering worst-case head winds due to weather, then a safety margin is added to allow the plane to divert to another airport in case of an outage at its destination.
2. Jetliners are structurally designed to safely resist worst-case loads due to weather turbulence and a substantial margin is added to ensure any degradation in structural strength during its lifetime will not endanger its safety. (The Comet jetliner in the early 1950s suffered two mid-air catastrophes from unsuspected metal fatigue leading to improved design practices across the entire aviation industry.)

[20] 2024 ISP Appendix A4 NEM resilience through prolonged droughts P25

Surely, the reliability of the NEM, which affects the entire economy, national security, jobs, well-being and the cost-of-living of all people, is just as important as it is in the aviation industry. IESP's submission to the Senate Select Committee on Energy Planning and Regulation advocated for the establishment of an independent regulatory certification agency with full technical and financial design analysis capabilities to hold AEMO accountable for the viability and safety of the NEM. It is a pity that this was not pursued in the final report.

5.3 Temporal Applicability

It is noted that VRE integration costs are modelled only for the 2030 LCOE case. Major subsequent growth in the grid design alters the balance of capacities in the NEM (per the ISP) thus leaving open the question of the applicability of the conclusions applicable to subsequent years.

5.4 Free Existing Capacities

The basic GenCost framework assumes free access to existing capabilities[21] for back up. This may apply for a system operating at non-peak conditions but system design must instead be based on absolute worst-case conditions, as detailed above and in Appendix 1. This logically leads to the fact that to achieve reliability, all dispatchable (i.e. flexible) resources are employed for back up under peak conditions and an adequate dispatchable reserve margin is maintained to guard against facility outages. This most certainly does not lead to low integration costs as claimed by GenCost. It would be unrealistic to plan to add a certain amount of VRE and assume that the flexible resources are in surplus and therefore can reduce the added integration costs.

5.5 Facility Lifetimes

Some of the facility lifetimes provided in GenCost's Appendix B Table B.9 require examination.

The assumed lifetime of 30 years for solar and 25 Years for wind are somewhat optimistic. Solar outputs degrade by about 2% in the first year and 1% per year thereafter although there is considerable variation. This reduces outputs by about 20-30% respectively after 20-30 years. Damage (e.g. hail storms) can also impact average lifetime. Solar farms will consider replacement when outputs can no longer deliver adequate returns. Lifetimes of 20-25 years have been widely used in many reports.

Wind turbine outputs degrade at about 1.6% per year according to a study of 292 wind farms in the UK.[22] Similar results were found by Lawrence Berkeley National Laboratory in a study of US wind farms, noting decline becoming steeper after ten years. Given the challenging conditions of operating environments and difficult access to the rotating equipment at high elevations, which requires constant lubrication, wind farm lifetimes are affected by serious failures such blade erosion, bearing wear out and fires as well as reduced outputs. A submission[23] to a Senate Select Committee on Wind Turbines pointed to world wide evidence showing some wind plants are barely managing 10 to 15 years. A more realistic lifetime is 20 years.

Nuclear plant lifetimes are listed in GenCost Table B.9 as 30 years, a figure that is far below reality. Section 2.1 discusses a 30 year "capital recovery" period as desirable because that would lead to operation in subsequent years free of capital costs and thus reduce interest costs. The proposed adoption of a 30-year capital cost recovery period increases LCOE in the first 30 years – somewhat convenient for comparison with VRE!

[21] Section 6.2.1 Framework for calculating variable renewable P58 and Table 6-1
[22] Stafell and Green, Imperial College How does wind farm performance decline with age. Renewable Energy 66 (2014) 775e786
[23] Anton Lang Submission to Senate Select Committee on Wind Turbines

The apparent mistake made in this GenCost section is that interest costs are compared to capital costs on a project basis. The reality, as shown in whole-of-system modelling in Appendix 2, is that the total capital costs required for the baseline ISP model are twice that for the nuclear mix alternative models. This has not been properly captured in the LCOE process.

Note that GenCost states[24] that "it is too early to be able to say what the total operational life is of more recent technologies such as solar PV and onshore wind."

5.6 Capacity Factors

Low and high assumptions for GenCost capacity factors require a rigorous review.

The 32% solar capacity factor is close to a theoretical maximum of 33%, given that solar is effectively at zero output for 16 hours of every day and this does not leave much room for cloud cover and non-optimum sun angles. A figure of 28% is often used and is still optimistic. According to GenCost note 30 on Page 60, a lower 19% figure is closer to average capacity factor and therefore more realistic.

Wind power capacity factors are unrealistically high and may be based on unusual sites. It is possible that a particular site, due to specific geographic features may experience very high and steady winds but that does not translate to a figure to be used for a collection of wind farm sites spread over a wide geographic area. For example,[25] the Fosen Vind onshore facility in Norway was projected to have a 39% capacity factor "while United States annual capacity factors from 2013 through 2016 range from 32.2% to 34.7%." Gencost postulates 29% to 48% for onshore wind capacity factors.

Offshore wind farms experience higher capacity factors due to more favourable and consistent winds. A Danish offshore wind farm recorded a capacity factor of 47.5% but this does not provide evidence that all wind farms around the Australian coasts will achieve the same level. Wind farm companies go to great lengths to survey potential sites for best wind statistics but the many constraints on regulatory approvals means that not all will have the same capacity factors.

The capacity factors for offshore wind are unrealistic with a low figure of 40% and high numbers at 52%, 54%, 57% and 61% in years 2024, 2030, 2040 and 2050 respectively. These also appear to be based on extreme outliers, which do not justify the application to a wider deployment of wind farms.

Nuclear plant capacity factors are assumed by GenCost to be in the 53% to 89% range.[26] GenCost rejects US experience showing over 94% as the average of many nuclear plants. Justifying 89% due to Australian inexperience is unrealistic and using coal plant records as the basis ignores the difference in some of the technologies and Australia's track record with Lucas Heights. Furthermore, the nuclear technologies Australia will install will be more modern than US legacy plants.

Setting the lower figure at 53% is completely illogical by tying it to coal plants that are being deliberately sidelined (forced to operate at uneconomic low utilisation rates) in favour of renewables by policies, regulations and taxes. Favouring intermittent renewables over emissions-free nuclear power would frankly be ridiculous given nuclear's advantages of long lifetime, reliable outputs, remarkably lower footprint, minimal damage to and disruption of the environment and dramatically lower vulnerability to weather and cyber attack. A future grid using nuclear power should prioritise its maximum utilisation to ensure its economics are as efficient as possible. It ticks all of the boxes and needs no back up other than a healthy grid DRM.

[24] GenCost Section 2.1.3 Allowing other technologies to benefit from multi-stage costing P19
[25] Wikipedia
[26] GenCost Section 2.2 Nuclear capacity factor range P21

5.7 Exclusions

GenCost explicitly excludes several very high cost elements[27]. It states that rooftop solar is excluded from VRE share. Instead, its effect is to reduce the "*demand load shape*". However, consumer PV resources are *60% of all solar in the ISP*. Their total cost, using ISP capacities times GenCost capital cost factors, to 2050 is $112B and possibly $155B if flat 2024 cost factors apply. On the other hand, utility solar cost is only is $71B to $104B.

Keep in mind that high reliability deign is driven by worst-case peak demand not some average demand shape used in a simulation model. The fact that consumer VPPs are expected by the ISP to contribute significant amounts of power to the grid to satisfy demands makes their exclusion unjustifiable.

The LCOE methodology does not appear capable of factoring in replacement costs for facility lifetimes. Batteries with a 10 year life, which are installed before 2030 will require replacement twice before 2050 and are the single most expensive cost element in whole-of-system modelling. See Appendix 2.

GenCost also states that "..*in 2030, a portion of customer-owned battery resources are assumed to be available to support the wholesale generation sector consistent with the approach taken in the AEMO ISP*." It appears that these batteries supporting the grid may be the 'free resources' referred to in Table 6-1. The 2024 ISP makes consumer batteries, which cost more than twice per unit of storage than utility scale batteries[28], *60% of all battery capacity by 2050*. Their capital costs to 2050 are $322B to $463B, the single largest cost element in the ISP, whereas utility batteries cost is $50B to $75B. These cost figures are simply the capacities listed in the 2024 ISP multiplied by the capital cost figures in GenCost and include replacements.

The justification for GenCost excluding costs for consumer resources is incomprehensible, unless its purpose in the ISP is to downplay the real costs of VRE integration. These costs may be free to an investor but they are being paid for by a vast number of consumers. These exclusions make the GenCost results entirely questionable for guiding government energy policies.

GenCost also assumes that Snowy 2.0 and battery of the nation pumped hydro projects, various transmission projects and the Kurri Kurri gas plant are all completed "immediately" for inclusion of their cost in 2024 estimates and therefore provided free to investors in 2030.[29] That is convenient for investors, essentially making them sunk costs, but does not provide meaningful cost estimates that the public and government policy makers need. Markets simply do not operate by facility owners providing free products and services to others.

This assumption is a continuation of a belief among renewables proponents that back-up facilities and their costs address a purported weakness in the network design and are not chargeable against the highly variable and intermittent power facilities. Conventional baseload generation does not require back-up facilities. The lack of responsibility of VRE to provide power as and when needed by consumers is a fundamental error in energy policy. No sensible power systems engineer would willingly choose to employ intermittent and highly variable power generators dependent entirely on weather. And neither would expensive battery storages, which would require massive increases in VRE to recharge them, be considered.

5.8 Transmission and Stabilisation

GenCost provides transmission costs in 2030 for REZ expansion and other reasons of $5.30/MWh and $4.20/MWh respectively. These estimates appear reasonable given the 2024 ISP identification of the

[27] GenCost Section 6.2.2 Key assumptions P60
[28] GenCost Section 5.3.13 Battery Storage P51
[29] GenCost Section 6.2.2 Key assumptions P62

requirement to build 10,000 km of transmission lines. However, grid stabilisation facility costs are not explicitly explained.

5.9 Distribution Networks

Low voltage distribution networks require substantial upgrading to handle very large load variations introduced by CER, which cause voltages to swing beyond standards thus risking consumer appliances and equipment connected to the grid. The 2024 ISP ignores this cost completely as does GenCost. We estimate this will cost $78B to $156B in the next 25 years compared to $35B to $55B for transmission lines. Amortised over 30 years with projected energy delivered, it amounts to about $11/MWh to $22/MWh. It must be emphasized that this cost is driven by the need to place VRE assets in homes and businesses and then harvest power into the grid from VPPs. It is not required by all other forms of baseload generation. It is a VRE integration cost.

5.10 Disposal, Recycling and Remediation

The ISP does not make any mention of disposal, recycling and remediation costs associated with VRE. GenCost explicitly states[30] that its costs do not include plant decommissioning and recycling.

Given that rural residences are currently reaching a state of high anger concerning installation of transmission lines, solar farms and wind turbines, it is now clear in media reporting that developers have no obligation for set asides to cover these costs and once a plant comes to end of life, the company is usually wound up leaving land owners to cover substantial costs to decommission and restore their property.

These costs are difficult to model but we estimate them as much as $26B to $52B over the next 25 years. There is a good chance that governments will be forced to impose these costs on developers.

5.11 Spillage

GenCost puts a cost on spillage, the amount of energy by which VRE is capable of supplying minus the delivered energy. It notes the method of calculation[31] and computes a figure of $15.10/MWh in 2030 with a 90% VRE share. It is instructive to compare it to the 2024 ISP's 2030 design. We calculate that the 2030 ISP VRE is capable of delivering 240 TWh at capacity factors of 28% and 33% respectively for solar and wind compared to forecast demand consumption of 187 TWh. The actual delivered VRE energy, assuming 50% capacity factor for baseload sources, amounts to 121 TWh, a spillage factor of about 50%. i.e. the implication is for a doubling of the LCOE which is based on delivered energy not average capacity.

The same calculation for the 2050 design is for a VRE share of 85% but a larger overbuild in ISP capability results in a spillage factor even larger at 55%. These figures represent the actual ISP design, not some theoretical model. How does GenCost reconcile this large discrepancy?

6.0 Whole-of-System Cost Modelling

The whole-of-system cost modelling in Appendix 2 is based on the use of 2024 ISP figures for generation and storage capacities for 2024, 2030, 2040 and 2050. These are multiplied by projected draft 2024-25 GenCost capital cost factors to obtain optimistic (low) capital cost estimates. A second set of estimates using flat GenCost 2024$ capital cost factors is used to provide high capital cost estimates.

Added to these cash flow estimates are modelled costs for transmission, stabilisation, distribution networks and disposal. These costs are more inclusive than those indicated in the draft 2024-25

[30] GenCost Section D.4.4 potential cost factors not included P99
[31] GenCost Section 6.2.2 P64 note 36

GenCost for LCOE analysis and the 2024 ISP. It must be kept in mind that the baseline model (Step Change) of the 2024 ISP has been shown in Appendix 1 to have large negative DRMs indicating gross unreliability.

Appendix 2 provides two alternative models attempting to rectify the unreliability of the ISP, using extra gas generation and battery storages respectively, to obtain positive DRM at 20% or above. It also presents models of four mixed technology grid design alternatives per the Table 1 below.

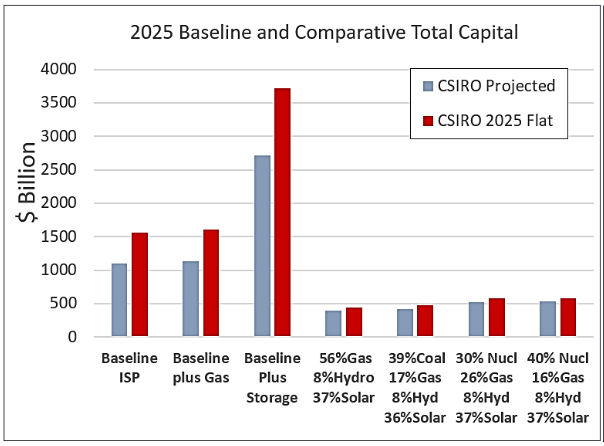
The results of this whole-of-system modelling analysis are shown in Figure 1 below for both real cash flow costs and present value discounted cash flow by 7% annually. Both high and low estimates are presented to provide a bracket of uncertainty.

A summary of the whole-of-system analysis in Appendix 2 is as follows:

1. The 2024 ISP baseline capital cost estimate exceeds one trillion 2024 dollars and is far larger, by a factor of about two, than any of the four grid design alternatives. Real cash costs are also about twice the computed present value estimate, which itself is about four times the estimate of $122 billion present value stated in the 2024 ISP.
2. The least expensive modification for improving the reliability of the ISP baseline design is to add significantly more gas generation, more than tripling it; the cost of augmenting with batteries is so expensive, it is simply unaffordable.
3. The gas dominant alternative model is the lowest capital cost but would have significant operating costs for fuel. (Note the baseline model also has gas generation fuel costs.)
4. Coal is the next lowest capital cost but has both coal and gas fuel costs. (Note the baseline model also has gas generation fuel costs.)
5. The two nuclear alternatives are slightly higher in capital costs but have very low fuel costs and offer increased lifetime of about 80 years.

Model	Coal	Gas	Hydro	Nuclear	Solar	Wind
1 Gas	0%	56%	8%	0%	37%	0
2 Coal	39%	17%	8%	0%	36%	0%
3 Nuclear/solar 1	0%	26%	8%	30%	37%	0%
4 Nuclear /solar 2	0%	16%	8%	40%	37%	0%

Table 1 Alternative Whole-of-System Configurations by 2050



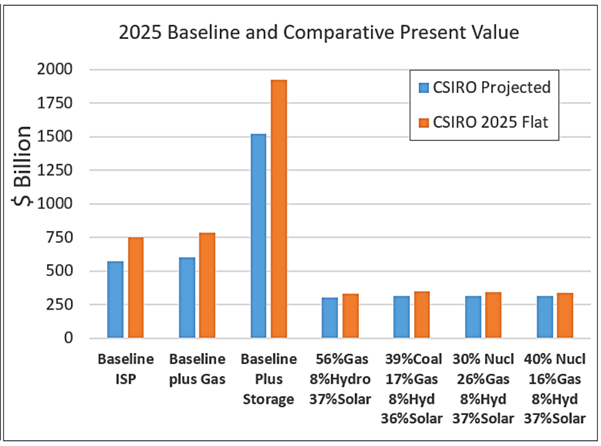


Figure 1 Whole-of-System Capital Cost Estimates

These results are probably no more or no less accurate than other models. However, the consistency of method applied to multiple grid design cases, likely gives improved relative accuracy. This analysis is founded on explicit ISP grid design data for the 2024 ISP baseline Step Change model and uses capital cost factors from the draft 2024-25 GenCost report.

The disparity between both the baseline model and baseline augmented with gas generation model as compared with the four alternative design models is a factor of about two – large enough to strongly indicate a valid result despite inherent uncertainties in model accuracy.

In light of these results, CSIRO should re-evaluate the LCOE methodology to explain why it indicates a result suggesting the complete opposite of whole-of-system analysis.

Appendix 1 - The AEMO 2024 ISP Will Not Deliver Reliable Power

AEMO's numbers just do not add up

A Report by Independent Engineers, Scientists and Professionals 11 August 2024 v3

Introduction

Our 9 February 2024 submission to AEMO and CSIRO concerning the *draft* ISP identified serious potential reliability problems resulting from AEMO's electricity grid design. Our inputs were largely ignored.

The final version of the ISP, released on 26 June 2024, essentially reveals the same deeply flawed model of the NEM electricity grid.

Failure to Address Clearly Stated Reliability Issues

AEMO's ISP suffers from severe deficiencies in capacities of both energy storage and baseload back up power, starting in the next few years and lasting throughout the entire period to 2050. It shows no evidence of rigorous system design engineering required for high reliability systems based on worst case conditions and healthy reserve margins.

By 2030, the dispatchable reserve margin falls from historic levels in excess of plus 20% to **minus 15.9%** and in subsequent years it is substantially worse. It cannot deliver adequate power when NEM-wide grid demand is maximum, when overnight solar is zero and wind output is close to nothing.

The negative reserve margin provides no allowance for facility outages for maintenance and repairs and leads to blackouts when demand peaks. The grid design also suffers from insufficient power capacity to quickly recharge the energy storages in order to prepare for the next set of worst-case conditions.

AEMO's own historical NEM data demonstrates periods of very low renewable energy production lasting 3 or more consecutive days and dramatic falls occur multiple times in a month. Periods of several months, when wind and solar outputs are well below long term averages, are evident in both Australian and overseas data. May 2024 witnessed several major wind droughts.

The energy storage capacity in the ISP is too low by at least a factor of ten. Adding more batteries and additional renewable generation to recharge them is completely unaffordable.

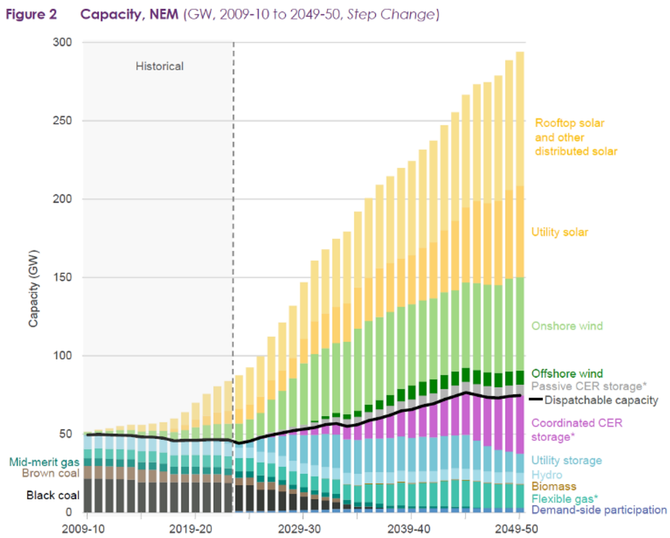
Deceptive Data Concerning Dispatchable Power

Figure 2 in the ISP is a graphical chart showing power from various generation sources and storages by year until 2050 (see next page).

It shows impressive growth to 2050 but almost all growth is in renewables, which have very low capacity factors (25-32%). Similarly, energy storage outputs show remarkable growth but most of these provide power for just a few hours. Much of it is from coordinated home resources which are uncertain and cost almost twice that for utility scale batteries. The dispatchable black line climbs to above 75 GW by 2050 but in truth, it is meaningless because much of it cannot be used to back up the grid when solar and wind power are largely absent for periods of 16 hours overnight, multiple days and significantly below average for periods of months.

This deceptive portrayal is merely a summation of maximum power outputs from all sources. A truthful depiction would, as a minimum include warnings to the effect that renewables provide less than one third of maximum power on average and not all dispatchable power provides practical levels for grid back up.

Figure 2.4 in our submission (see below) provided an alternative version of this chart showing the true dispatchable power over various periods based on ISP data for energy storages (ISP Figure 20). By 2040, the dispatchable power of AEMO's ISP design falls to just 30 GW for backup durations of one week but at the same time it indicates that for 16 hours overnight, it is only 37 GW. However, a proper engineering design with a 20% dispatchable reserve margin will require over 62 GW by 2040.



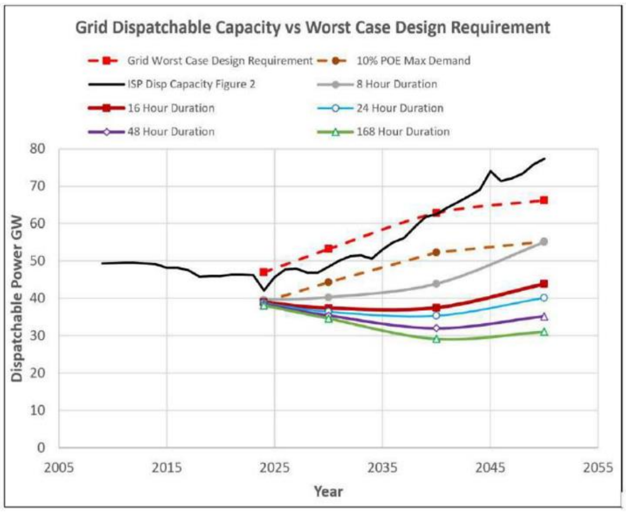


Figure 2.4 Dispatchable Power Capacity vs Grid Design as a Function of Duration

A Whole-of-System Power Budget Shows Failure of Reliable Power at Night

A whole-of-system power budget is fundamental to understanding the viability of the AEMO ISP and making a counterpoint to the CSIRO GenCost report, however, the ISP provides no system level power budget. In fact, the ISP does not contain any data on maximum demand. Instead, it forecasts average annual energy production figures. This is no way to design a high reliability system.

Proper high reliability engineering design requires use of real worst-case conditions plus a margin for facility outages for maintenance and repairs. A whole-of-system power budget (table on the next page) is based entirely on AEMO's ISP data.

The power budget is updated with August 2024 ESOO maximum grid demand data (v3).

We show that by 2030, the dispatchable reserve margin falls to minus 15.9% on a single 16-hour overnight period when solar and wind fall to zero and baseload sources are run at full capacity. Any facility outages for maintenance or repairs will make this figure worse. There is simply not enough baseload power nor energy storage capacity.

To restore the dispatchable reserve margin to at least plus 20% would require an additional 15.3 GW of baseload or equivalent stored energy outputs in 2030, rising to 19.5 GW in 2040.

In the event of multiple day wind and solar drought conditions, there is not sufficient surplus power during daytime to completely recharge expanded energy storages sufficient to handle another overnight period under worst case conditions. This was evident in the ISP's 8 day simulation of non-worst case conditions (see below).

Blackouts are inevitable. The AEMO ISP cannot deliver reliable power under worst case conditions. This is not a matter requiring fine tuning of the grid design. It is a massive failure.

2024 Final ISP Top-Down Whole-of-System Power Budget

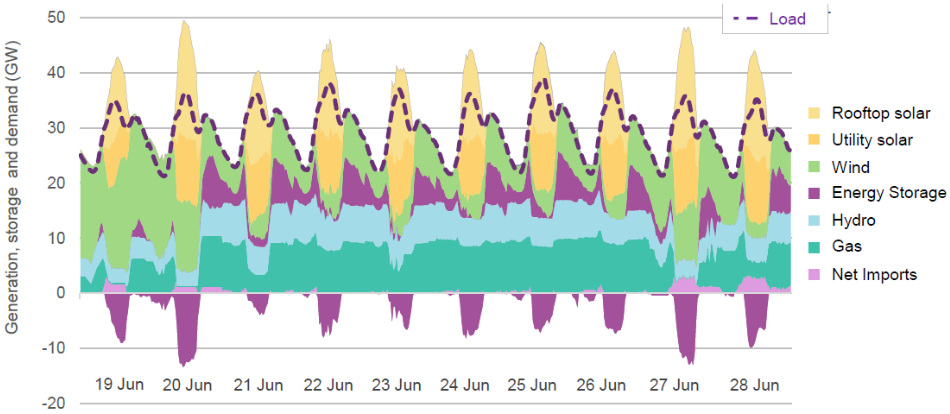
AEMO NEM Grid Design per 2024 FINAL ISP														
Worst Case & 20% Reserve Margin			**2024-25**			**2029-30**			**2039-40**			**2049-50**		
24 hr Top-level Whole-of-System Power Budget			**Capacity**	**Night**	**Daytime**	**Capacity**	**Night**	**Daytime**	**Capacity**	**Night**	**Daytime**	**Capacity**	**Night**	**Daytime**
Duration hours				16	8		16	8		16	8		16	8
NEM Power Demand				**GW**	**GW**		**GW**	**GW**		**GW**	**GW**		**GW**	**GW**
10% POE Max Demand (ESOO 2024)	Relative to 2023		2.3%	40.0	40.0	-4.0%	42.6	42.6	-12.2%	45.9	45.9	-13.8%	47.6	47.6
Dispatchable Reserve Margin	20%			8.0	8.0		8.5	8.5		9.2	9.2		9.5	9.5
Total Power Design Requirement				**48.0**	**48.0**		**51.1**	**51.1**		**55.1**	**55.1**		**57.1**	**57.1**
Power Sources (Fig 2 2024 ISP)	**Capacity Factors**		**Capacity**	**Delivered**		**Capacity**	**Delivered**		**Capacity**	**Delivered**		**Capacity**	**Delivered**	
Baseload Power	**Night**	**Daytime**	**GW**	**GW**	**GW**	**GW**	**GW**	**GW**	**GW**	**GW**	**GW**	**GW**	**GW**	**GW**
Coal - Black & Brown	100%	100%	21.2	21.2	21.2	11.44	11.4	11.4	0	0.0	0.0	0.0	0.0	0.0
Gas - Mid Merit & Flex	100%	100%	12.6	12.6	12.6	11.62	11.6	11.6	15.89	15.9	15.9	15.0	15.0	15.0
Additional Flex Gas	100%	100%	0	0.0	0.0	0	0.0	0.0	0	0.0	0.0	0.0	0.0	0.0
Hydro	100%	100%	6.84	6.8	6.8	6.84	6.8	6.8	7.14	7.1	7.1	7.07	7.1	7.1
Biomass	100%	100%	0	0.0	0.0	0	0.0	0.0	0.45	0.5	0.5	0.45	0.5	0.5
DSP (Info only)			0			0			0			0.00		
Total Baseload Dispatchable			**40.6**	**40.6**	**40.6**	**29.9**	**29.9**	**29.9**	**23.5**	**23.5**	**23.5**	**22.5**	**22.5**	**22.5**
Energy Storage (Fig 20 2024 ISP)			**GWh**			**GWh**			**GWh**			**GWh**		
Snowy 2.0 + Borumba			0.0			349.80			397.75			397.75		
Deep			6.27			6.27			54.44			77.81		
Medium, Shallow, Coord CER			12.27			55.27			104.85			170.42		
Total Storage Capacity			**18.5**			**411.3**			**557.0**			**646.0**		
			Capacity	**Delivered**		**Capacity**	**Delivered**		**Capacity**	**Delivered**		**Capacity**	**Delivered**	
Storage Max Power Capacity			**GW max**	**GW**	**GW**	**GW max**	**GW**	**GW**	**GW max**	**GW**	**GW**	**GW max**	**GW**	**GW**
Snowy 2.0 + Borumba			0.0	0.0		2.2	2.2		4.2	4.2		4.2	4.2	
Deep (limited by max power output)			0.25	0.25		0.25	0.25		1.41	1.41		2.48	2.48	
Medium, Shallow, Coord CER (avg output overnight)			3.71	0.8		19.2	3.5		34.2	6.6		42.63	10.7	
Total Max Storage Power			**4.0**			**21.65**			**39.81**			**49.3**		
Avail. Storage Power Dispatchable				**1.0**	**0.0**		**5.9**	**0.0**		**12.2**	**0.0**		**17.3**	**0.0**
Total Dispatchable Power				**41.7**	**40.6**		**35.8**	**29.9**		**35.6**	**23.5**		**39.8**	**22.5**
Surplus/Deficit(-) wrt 10% POE Demand				**1.6**	**0.6**		**-6.8**	**-12.7**		**-10.3**	**-22.5**		**-7.7**	**-25.1**
Dispatchable Reserve Margin				4.1%	1.5%		-15.9%	-29.7%		-22.4%	-48.9%		-16.2%	-52.7%
VRE Renewables (Fig 2 2024 ISP)	**Capacity Factors**		**Capacity**	**Delivered**		**Capacity**	**Delivered**		**Capacity**	**Delivered**		**Capacity**	**Delivered**	
	Night	**Daytime**	**GW**	**GW**	**GW**	**GW**	**GW**	**GW**	**GW**	**GW**	**GW**	**GW**	**GW**	**GW**
Wind: Onshore	0%	0%	13.0	0.0	0.0	39.3	0.0	0.0	51.9	0.0	0.0	59.5	0.0	0.0
Wind - Offshore	0%	0%	0.0	0.0	0.0	0.0	0.0	0.0	9.0	0.0	0.0	9.0	0.0	0.0
Solar Utility	0%	0%	9.5	0.0	0.0	15.6	0.0	0.0	31.2	0.0	0.0	58.3	0.0	0.0
Solar Distributed VPP	0%	0%	23.5	0.0	0.0	36.1	0.0	0.0	60.2	0.0	0.0	85.7	0.0	0.0
Non-dispatchable VRE			**46.0**	**0.0**	**0.0**	**90.9**	**0.0**	**0.0**	**152.2**	**0.0**	**0.0**	**212.5**	**0.0**	**0.0**
Total Dispatchable + VRE Power				**41.7**	**40.6**		**35.8**	**29.9**		**35.6**	**23.5**		**39.8**	**22.5**
Surplus/Deficit(-) wrt 10% POE Demand				**1.6**	**0.6**		**-6.8**	**-12.7**		**-10.3**	**-22.5**		**-7.7**	**-25.1**
	Efficiency				**GW**			**GW**			**GW**			**GW**
Req'd Daytime Recharge Power	**80%**				**2.5**			**14.8**			**30.4**			**43.3**
Avail. NEM Daytime Recharge					**-6.2**			**-17.6**			**-26.4**			**-28.8**
Recharge Power Surplus/Deficit(-)					**-8.7**			**-32.4**			**-56.8**			**-72.1**

AEMO's Attempt to Demonstrate System Reliability is Misleading

In Section 6.5 "Reliability and security in a system dominated by renewables", the ISP acknowledges the challenge as renewables approach 100% of generation. But it claims: "*Consumers should be confident that the NEM's mix of technologies will keep electricity supply secure and reliable during normal operation, extreme peak demand and renewable droughts*."

In the ISP, Figure 24 (p72) attempts to illustrate operability through an eight-day renewable drought for the "NEM except Queensland". ISP Appendix 4 (Figure 15 p 26) reveals that this simulation test involved an "extended VRE drought event running from 21 June 2040 to 28 June 2040 (reflective of conditions observed historically in June 2019)."

Figure 24 Operability through eight-day renewable drought, NEM except Queensland



This one-off test looks impressive but is merely an illustration far short of what a proper engineering analysis would require. A detailed examination of the data behind this test revealed the following:

1. It assumes imports of power from QLD, yet represents it as a partial system.
2. It assumes maximum power continuously from all dispatchable resources. i.e. no facility outages.
3. It assumes not-so-extreme VRE drought conditions were for 6 days not 8 as indicated by the light green wind data in the chart.
4. It assumes wind capacity factor was 10% in daytime; 13% overnight – not worst case.
5. It assumes solar capacity factor was 13-15% - not worst case.
6. Non-daytime grid demand in early evening was about 32 GW, afterwards decreasing by 31% to 22 GW; this profile is highly speculative in the face of increasing EV demand for overnight charging; no amount of social licence will be gained by draining EV batteries into the grid at night and forcing owners to recharge them during the day; worst case is a flat maximum demand.
7. The ISP admits that "reliability risk would be "elevated", particularly if major generator or transmission outages occur" i.e. no facility outages were taken into account.

These are certainly NOT rigorous worst-case conditions. Instead of illustrating the reliability of the NEM grid design, this test indicates the extent to which the AEMO ISP misrepresents its viability. A close look at this chart shows no reserve margin at all – every night of the 8-day "drought" shows the very low load being exactly met by all dispatchable sources at 100% and 13% wind - no reserve margin at all, unlike daytime when solar exceeds load. In fact, this fortuitous result looks somewhat contrived.

This highly dubious simulation test has more to do with marketing than proper system engineering.

Conclusions

Despite its impressive appearance, the ISP contains fundamental technical drawbacks. From an engineering perspective, the AEMO ISP is seriously flawed and fails to provide assurance that the NEM grid design has been developed in accordance with modern system engineering principles for high reliability systems.

We therefore conclude the AEMO ISP, which underpins the entire national economy, will not serve Australian consumers and businesses with reliable electrical power. It is clear this plan has been driven by changes to National Electricity Rules by non-technical politicians and bureaucrats to set artificial goals for renewables divorced from engineering realities.

It is critically important and urgent that an ongoing review process be implemented with advice and input by independent experts to oversee AEMO and CSIRO work on the future NEM.

It is beyond time for AEMO to state clearly its worst-case design criteria, worst-case demand and minimum dispatchable reserve margin capable of providing usable outputs for periods of many days not hours. AEMO must then provide proper systems engineering analysis showing grid performance under these conditions.

It is painfully necessary to conclude that the AEMO ISP is either deliberately misleading or fails due to incompetence. Neither is acceptable in leading a transition which will likely end in disaster for the entire economy. We have no knowledge of the qualifications of AEMO's staff but it seems plausible that AEMO's operational success over the years must be due to highly qualified power systems engineers. The truth for this failure must be uncovered.

Independent Engineers, Scientists and Professionals

This report has been prepared and supported by independent engineers, scientists and professionals who have many decades of relevant experience and requisite qualifications without any monetary conditions, employment or conflicting interests.

William Bourke, BSc, BEng (Aero), MEng Sc.
Ben Beattie, BE(Elec), CPEng RPEQ
Michael Bowden IEng (Electronics-UK); CPL; CQP
Rafe Champion, M.Sc (History and Philosophy of Science), B.Ag.Sc. (Hons)
Paul R C Goard, BSc, Physicist, M.A.I.P., M.I.of P., M.A.I.E., M.A.M.O.S.
Peter J F Harris, BEng, Dipl. Prod Eng.
Professor Emeritus Aynsley Kellow, BA(Hons) PhD
John McBratney, B. Tech (Electronic Engineering), formerly MIE Aust, MIEEE
Paul McFadyen, BSc, MSc, PhD
Emeritus Professor Cliff Ollier, DSc
John McLean, PhD
James R (Jim) Simpson, (Ret., former business unit manager, OTC & Telstra)
Walter Starck PhD (Marine Science)
James Taylor, PhD, MSc, BEng Elect (Hon), PEng, FCASI
Lawrence A P Wilson, D.App.Chem, D.Chem.Eng, B.Comm (Economics)

Corresponding Author: james.taylor861@gmail.com

Appendix 2 - The Missing Whole-of-System Cost Model in the AEMO 2024 ISP

The Real Cost of the NEM Transition

A Report by Independent Engineers, Scientists and Professionals 31 July 2024 v3

Summary

The government has not provided a true estimate of cost for AEMO's plan to transition the NEM to intermittent wind & solar, yet it claims adding reliable nuclear and gas power generation is too costly.

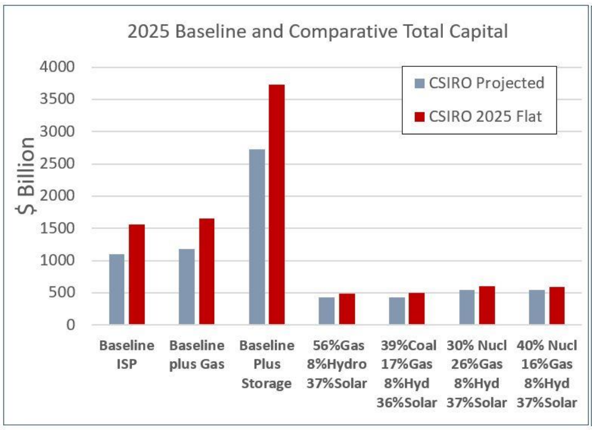
AEMO published its 2024 Integrated System Plan (ISP) in June. It contains only one paragraph[32] to indicate annualised capital costs as either $122 billion present value, not including "commissioned, committed or anticipated projects, consumer energy resources, or distribution network upgrades". This unrealistic, poorly defined estimate needs much clarification.

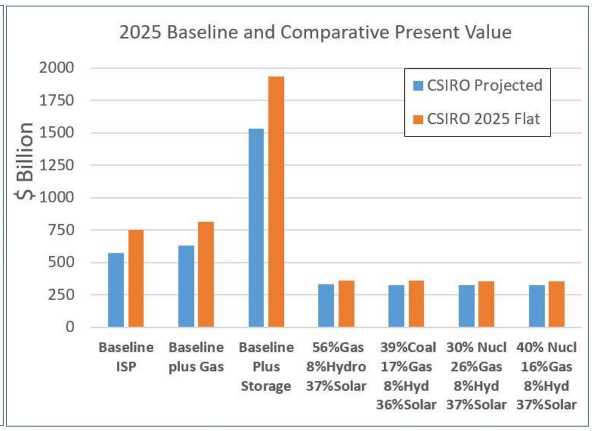
The whole-of-system analysis in this report, draws on 2024 ISP capacities for generation and storages and CSIRO draft 2024-25 GenCost cost factors[33]. It shows total capital costs for the 2024 ISP at over one trillion dollars – for a system unable to deliver reliable power[34]. This is about twice the capital costs of four alternative grid designs using gas, coal and nuclear. When fuel costs for gas and coal are considered, nuclear plus gas designs are likely to be the least costly of all options.

A More Comprehensive Capital Cost Analysis

The whole-of-system cost charts in Figure 1 below provide both real total capital and present value for a top-level model of the planned NEM grid transition, showing a present value more than four times higher than the 2024 ISP figures. Estimates include both CSIRO's somewhat optimistic declining future capital cost factors and its flat 2024 cost factors to reflect uncertainties in forecasting. The Baseline 2024 ISP estimates include all generation and storage costs including consumer energy resources, transmission lines, distribution network upgrades and other support costs to reflect the total costs to the economy.

Extending the Baseline ISP with additional gas or storage to overcome the major unreliability of the ISP's design incurs extra costs and makes clear that 'firmed renewables with batteries' are unaffordable. Four alternative designs using gas, coal and nuclear provide comparisons. The results, based on AEMO and CSIRO data, show that the present transition plan is the most-costly approach by a large margin.





[32] AEMO 2024 Integrated System Plan Page 74

[33] 2024 ISP Figures 2 and 20; draft 2024-25 GenCost Section 5.3;

[34] The 2024 AEMO ISP Will Not Deliver Reliable Power, Independent Engineers, Scientists and Professionals, 11 August 2024 v3

Figure 1 AEMO 2024 ISP Baseline and Comparative Whole-of-System Capital Costs in 2024 dollars.

Conclusions

1. Our analysis of the ISP uses a proper high reliability systems engineering approach to assess a 24-hour cycle under <u>worst-case</u> conditions of maximum demand, wind and solar droughts and the need for a minimum 20% dispatchable reserve margin (DRM)[35] to guard against facility outages. A whole-of-system 'Baseline ISP' power budget using 2024 ISP capacities shows the DRM at minus 15.9% by 2030 and falling lower by 2040. Widespread and frequent blackouts are certain.
2. Adding battery storages and extra wind & solar to recharge them ('firmed renewables') to achieve 20% DRM overnight results in completely unaffordable total capital costs of several trillion dollars and provides storage for just one 16-hour overnight period. And it still leaves daytime DRM massively negative. Battery storage capacity for one week requires $5-7 trillion. Replacements every decade would cost upwards of $3.5 trillion. This is simply not a viable path.
3. Alternatively, adding gas to existing hydro to essentially duplicate the grid when wind and solar are in drought requires a not-insignificant additional capital cost of $30-60 billion. It would provide continuous backup capability but operate at lower utilisation making its economics unattractive.
4. The four alternative grid designs are 56% gas plus 8% hydro & 37% solar, 39% coal plus 17% gas, 8% hydro & 37% solar, 30% nuclear plus 26% gas, 8% hydro & 36% solar, and 40% nuclear plus 16% gas, 8% hydro & 37% solar. They provide reliable 24/7 power with less than about half the capital costs. The nuclear options, with lifetimes up to 80 years lasting far beyond 2050 compared with wind and solar, minimise costs for gas and probably reduce emissions to less than the Baseline ISP, once whole-of-life emissions for mining, processing and manufacturing of almost 900 times more material is taken into account. All four alternatives impose a tiny environmental footprint compared to the 1.6 million hectares for the Baseline ISP design maximising wind & solar.
5. It is clear that contrary to continual claims that wind & solar are the cheapest form of electricity generation, it is in fact the most expensive when proper whole-of-system estimates are made. The present plan for transition of the NEM is disastrous in terms of reliability, cost to the economy and in particular to the environment, without being a path to the lowest emissions.
6. The alternative cost models assume wind & solar installations taper off after 2030. At additional cost, some solar generation can be maintained in the long-term grid design.

Recommendations

1. A thorough investigation by independent authorities must be commissioned and immediate start be made to implement effective accountability mechanisms to counter the complete failure of public energy policy regarding reliability and energy costs based on misleading information from public institutions.
2. The AEMO ISP and CSIRO GenCost documents must be subjected to higher genuine standards for truthfulness, completeness and professional engineering processes in place of slavishly following flawed existing policies.
3. Embedding wind & solar targets into the National Electricity Rules must be halted to end the replacement of power systems engineers by politicians and government bureaucrats without proper engineering qualifications selecting technological design solutions.
4. Independent expertise for frequent technical and financial review must be employed in new on-going accountability processes at multiple levels and points in time with a mandate to examine and openly examine a wide range of technological approaches.
5. The AEMO 2024 ISP must be discarded and an immediate start be made on a new energy NEM plan considering all power system technologies.

[35] DRM is the sum of baseload power over maximum demand. In 2019 the DRM was plus 20% (AER)

Independent Engineers, Scientists and Professionals

This report has been prepared and supported by independent engineers, scientists and professionals who have many decades of relevant experience and requisite qualifications without any monetary conditions, employment or conflicting interests.

William Bourke, BSc, BEng (Aero), MEng Sc.
Ben Beattie, BE(Elec), CPEng RPEQ
Michael Bowden IEng (Electronics-UK); CPL; CQP
Rafe Champion, M.Sc (History and Philosophy of Science), B.Ag.Sc. (Hons)
Paul R C Goard, BSc, Physicist, M.A.I.P., M.I.of P., M.A.I.E., M.A.M.O.S.
Peter J F Harris, BEng, Dipl. Prod Eng.
Professor Emeritus Aynsley Kellow, BA(Hons) PhD
John McBratney, B. Tech (Electronic Engineering), formerly MIE Aust, MIEEE
Paul McFadyen, BSc, MSc, PhD
Emeritus Professor Cliff Ollier, DSc
John McLean, PhD
James R (Jim) Simpson, (Ret., former business unit manager, OTC & Telstra)
Walter Starck PhD (Marine Science)
James Taylor, PhD, MSc, BEng Elect (Hon), PEng, FCASI
Lawrence A P Wilson, D.App.Chem, D.Chem.Eng, B.Comm (Economics)
Corresponding Author: james.taylor861@gmail.com

Attachment A Estimation Methodology

A. The AEMO 2024 ISP provides the data (Figures 2 and 20) regarding NEM capacities of all generation (GW) and energy storages (GWh) in 2024-25, 2029-30, 2039-40 and 2049-30.

B. The CSIRO draft 2024-25 GenCost report (Section 5.3) provides projected capital cost factor data (in 2024 dollars) for various energy technologies. This data excludes of all subsidies, offsets and tax breaks, which nevertheless have to be paid by all consumers in one form or another.

C. Since the projected cost factors are largely declining and are based on forecasts, which contain substantial uncertainties, a second estimate using flat CSIRO 2024 cost factors provides higher cost estimates reflecting potential upsides.

D. A power budget for each grid design model is based on a 24-hour cycle broken into 8 hours centred on midday when solar is available and 16 hours overnight when solar is zero. The DRM is the surplus/deficit of the sum of baseload power over peak demand in each of the 8- and 16-hour periods. Stored energy is used only during overnight periods to contribute to dispatchable power; recharging takes place in daytime when solar is expected to be available but is also subject to weather conditions causing low outputs.

E. Except for the Baseline 2024 ISP model using only the capacities specified in the ISP, the capacity data for other models is adjusted to achieve a DRM in each year of at least plus 20% to ensure reliability in the face of facility outages.

F. The capital costs of Snowy 2.0 and Borumba pumped hydro facilities are taken from current government announcements. Costs of passive storages behind the meter are included because they lower demand while making no direct input to the grid.

G. The capital costs prior to 2024-25 are estimated using the 2024 ISP capacities and CSIRO draft 2024-25 GenCost cost factors.

H. The capital costs for each of three periods, 2024-30, 2030-40 and 2040-50 are estimated as the sum of the various generation capacities installed in each period plus the replacement for past installations that have exceeded lifetimes and valued by the cost factor for the mid-point of each period.

I. The modelled lifetimes are 10 years for batteries, 20 years for wind and solar, 30 years for gas, 50 years for coal and 80 years for pumped hydro and nuclear.

J. Costs for existing hydro facilities were not included in any models due to lack of data. Costs for existing coal plants were not included since they are near end-of-life and being retired.

K. The present value estimate is derived by applying a 7% per annum pre-tax, real discount rate applied to capital expressed in 2024 dollars in three periods: 2024-30, 2031-40 and 2041-50 at mid points.

L. The demand side participation (DSP) capacity defined by the 2024 ISP is not used since it is clearly not a source of power but rather a reduction in demand brought about by time-of-use tariffs and central controls to impose rationing on consumers. i.e. this misguided policy attempts to make customers serve a deficient grid design rather than the grid delivering power to consumers as and when required. Social licence is unlikely when the public discovers its ramifications.

M. NEM peak demand is defined by AEMO's 2024 ESOO report for 10% Probability of Exceedance (POE) loads based on detailed forecasting.

N. The AEMO ISP's use of daily demand profiles to demonstrate grid performance is rejected for use in high reliability system design, which requires worst case conditions. The advent of EV recharging overnight and data centre 24/7 loads will flatten future demand profiles (according to the 2022 ISP and supported by surveys which show most EV owners prefer/require overnight charging). Incentives (e.g. punishing tariffs) to recharge during daytime when solar power is often in surplus is highly problematic and unlikely to gain social licence. Worst case system design must use a flat peak demand. The 10% POE peak demand design requirement provides further support for a conservative approach to worst case conditions.

O. Other costs applied to all models include transmission lines, low voltage distribution networks, grid stabilisation facilities, land acquisition for transmission lines (land costs are included in Gencost cost factors for generators), and an allowance for disposal, recycling and remediation.

P. While the accuracy of this whole-of-system cost estimation methodology is not precise, neither are all system model projections, which inevitably contain considerable uncertainties in predicting future costs and demands across 25 years. However, we apply the same methodology to all seven case models, thus making relative accuracy among them better than absolute accuracy.

Attachment B Cost Model Notes

Baseline 2024 ISP Case

The Baseline ISP 2024 grid design contains severe deficiencies in both baseload power and energy storage capacity causing the DRM by 2030 to be minus 15.9% instead the desired plus 20% – a shortage of 35% in dispatchable power. For 2040 and 2050, the shortages exceed 50%.

Such a design could only be based on hopes that weather conditions will always enable 'some renewable power' to be produced in 'some parts' of the grid to be delivered to the rest of the NEM by an extensive network of transmission lines. However, AEMO's historical power supply data[36] tells a different story of frequent periods, often on windless nights, when NEM available solar and wind power capacity factors fall to zero or close to it for wind. Some drought periods can last for more than three days and repeated episodes can often occur with only short intervals in between. Prolonged months-long spells can cause average renewable capacity factors well below expectations.

The AEMO 2024 ISP is a deeply flawed grid design which cannot deliver reliable power – blackouts are inevitable.

The cost of transmission network upgrades is based on the 2024 ISP plan to install 10,000 km of new transmission lines. Costs are estimated to be $1.3 to 2.0 million per km and subject to escalation. Significantly less transmission line costs are required for the four alternative cases.

The 2024 ISP "…assumes upgrades and other investments needed to enable distribution networks…. will occur through other mechanisms…". This study makes an estimate for distribution network upgrade costs of 5-10 thousand dollars per house based on expert opinion[37]. Much of this cost becomes unnecessary for the four alternative cases.

Stabilisation facilities such as synchronous condensers (costing $10-20 million each) will increasingly be required as baseload plants with rotating machinery are retired in favour of systems using electronic inverters. However, as with the transmission and distribution network costs, much of this is unnecessary for the four alternative cases.

[36] Independent Engineers, Scientists & Professionals, Submission to AEMO CSIRO Draft 2024 ISP GenCost 9Feb2024, P18-20

[37] Electric Power Consulting Submission on the 2024 Draft AEMO Integrated System Plan

Land acquisition costs for transmission lines are estimated from $200K-230K per km and are a subject of considerable debate in project approval hearings, where social licence is in short supply.

There is little information on projected costs for disposal, recycling and land remediation as a result of very substantial materials from expired wind turbines, solar panels and batteries. A nominal figure of $1-2 billion per year in future is used as large volumes of required replacements build up in the Baseline ISP case.

Baseline Plus Additional Gas Generation Case

The 2024 ISP phases out coal generation by 2037 and replaces CCGT (merit) gas plants with OCGT (flex) gas plants (designed to some day burn hydrogen, if or when available). To restore a plus 20% DRM, this case adds much additional gas generation, starting in 2030, to more than triple the planned level by 2050. The daytime period is most critical since the minimal 2024 ISP storages will be depleted overnight and are primarily intended to handle short peak demands and transients.

Maximum gas generation, hydro and biomass baseload provide a 20% reserve margin indefinitely during daytimes which rises well above 20% combined with storages at night. At night, gas generation would probably be lowered to reduce emissions but also at the cost of reducing the capacity factors of gas plants and their economic efficiency.

One implication of this case is the need to assure domestic gas supplies and deliver infrastructure are sufficient.

Costs for transmission lines and other elements remain as for the baseline case. Table 1 provides a summary of key power system demand and DRM.

	2029-30		2039-40		2049-50	
	Night	Day	Night	Day	Night	Day
	GW	GW	GW	GW	GW	GW
Peak Demand	44.3	44.3	52.3	52.3	55.2	55.2
Baseload Power	53.2	53.2	62.5	62.5	66.5	66.5
Storage Power	5.9		10.8		16.2	
Dispatchable Reserve Margin %	33.3	20.0	40.1	19.5	49.7	20.5

Table 1 Baseline Plus Gas Generation Case

Baseline Plus Additional Storage Case

This case leaves gas generation the same as in the Baseline case and retires coal generation in the 2030s. A massive addition of extra utility battery storage of almost six times the level in the 2024 ISP by 2050, is required to achieve a DRM above 20% to protect against a worst-case wind & solar drought on windless nights. And this also requires a corresponding massive increase in wind & solar to recharge them.

Even this large storage capacity would only cover a single night under worst case conditions.

The capital cost is estimated at $2.6-3.9 trillion. Since the marginal cost of adding batteries is $485 billion per day of storage, a grid system with a seven-day battery storage capacity would have a total capital cost of $5-7 trillion, even without adding more renewable recharge capability. The 10-year life of batteries also incurs massive ongoing replacement costs on the order of $3.5 trillion per decade.

Moreover, two further interrelated problems need addressing. The DRM during daytime – absent storage outputs – is disastrously below minus 50% so that there is no means to recharge the large battery capacity in the event of a daytime wind & solar drought.

This reality forces reliance on a minimum level of at least 10% capacity factor for all wind and solar generation. This is not a real solution for DRM since wind & solar are not dispatchable.

In view of these estimates, this case, widely touted as "firmed wind & solar with big batteries", is simply neither technically viable nor economically affordable.

A Gas Dominant Case (56% gas plus 8% hydro & 37% solar)

This case follows on from the Baseline plus added gas case. Capital cost is minimised by keeping the same gas generation, which together with hydro can indefinitely provide the plus 20% DRM both night and day. By halting further rollout of both wind & solar and battery storage after 2030, major capital cost savings are obtained as a trade-off against a lower reduction of operating emissions.

However, it should be noted that gas generation has about half the emissions of the present coal-based grid. This case also avoids the substantial emissions involved in mining, processing and manufacturing of all of the materials required for wind turbines, solar panels and batteries and their frequent replacements. The amount of such materials has been estimated at about 700-900 times the materials needed for a typical baseload power plant. Therefore, the net increase in emissions of this case may not be substantial.

Further, the very small environmental footprint of this alternative is negligible compared to wind and solar farms and is therefore another factor for consideration.

Another significant benefit is that gas and hydro facilities will run at higher capacity factors providing more attractive returns for investors, thus providing greater market stability and improving national productivity.

A Coal Dominant Case (39% coal plus 17% gas, 8% hydro & 37% solar)

This Case is a continuation of using coal generation and its expansion. Instead of retiring existing coal plants, they are replaced with high efficiency/low emissions (HELE) plants and expanded to double the present capacity by 2050. As for the previous case, wind & solar and storage rollouts are halted after 2030.

While limited emission reductions are evident in this case, potential exists for using advanced coal plant technology to improve efficiency. Carbon capture is not part of this model. However, benefits include the avoidance of renewable facility costs, a negligible environmental footprint and reduction of substantial emissions from mining, processing and manufacture of wind & solar.

As for the previous case, another significant benefit is that coal, gas and hydro facilities will run at higher capacity factors providing more attractive returns for investors, thus providing greater market stability and improving national productivity.

A Moderate Nuclear Case (30% nuclear plus 26% gas, 8% hydro & 36% solar)

For this alternative, the draft GenCost 2024-25 cost assumption for large scale nuclear power plants is used. Ongoing product development of SMR systems is proceeding briskly at multiple companies including Rolls Royce (the manufacturer of the planned AUKUS submarine reactors). SMRs offer a vision of production line manufacturing efficiencies for standard products, which will be approved by multiple countries as are commercial jetliners, thus simplifying and shortening the approval process.

It will be several years before SMR products are sufficiently mature to be able to assess their true cost factors. This has not prevented many countries from already placing orders for SMRs. Unless SMRs offer electricity costs that are competitive with large-scale nuclear plants, they will not become successful products and will simply disappear from the market.

Nuclear fission power plant technologies have a 70-year history of increasing safety, maturity, minimal environmental impact and zero operating emissions, which provides an attractive option.

This case posits a blend of gas (for fast reaction to load variations and grid transients) and nuclear power generation. The draft 2024-25 GenCost capital cost assumption for large scale nuclear plants can be favourably compared with other generation technologies when amortised for estimated lifetimes as indicated in Table 2, even though solar and wind cost factors ignore system integration costs. Financing interest costs for nuclear over an 80 year lifespan would actually be less than the interest costs of the ISP baseline over 80 years given its capital costs are twice as much.

From this comparison, a nuclear power plant is effectively much more competitive than the GenCost 2024-25 results would indicate.

	Nuclear	**Gas**	**Solar**	**Onshore Wind**	**Offshore Wind**
Draft GenCost 2024-25 Cost Assumption $B/GW	8.5	2.0	1.4*	3.0*	6.7*
Lifetime Years	80	30	20	20	20
Nuclear Cost Assumption $B/GW Amortised to Equivalent Lifetime	*8.5*	*3.2*	*2.1*	*2.1*	*2.1*

* Not including substantial system integration costs

Table 2 Equivalent Nuclear Capital Cost Factor Amortised for Equivalent Lifetime

In this case, rollout of wind, solar and storages are halted after 2030 because nuclear and gas baseload generation can run continuously, thus avoiding further capital costs. As its capital cost is much higher than gas plants, nuclear plant should be run continuously at high utilisation rates to achieve the lowest unit cost. The fuel cost per KWh is much less than gas. The gas component provides an ability to quickly ramp up and down to compensate for variable load demands.

Since nuclear plant installation is unlikely to commence before mid-2030s, it is vital that new gas generation facilities be launched as soon as possible supported by expansion of domestic gas production infrastructure on the east coast. Gas is a critical component of all viable future electricity grid options. There should be no equivocation, unless it is preferred to maintain coal generation indefinitely. Gas will be the bridge to and ongoing support to reliable nuclear generation.

If it is desired to maintain some level of wind & solar in the grid, the substantial gas generation in this Case provides plenty of scope for backing up wind & solar. However, this will lower the capacity factors of the gas plants thus increasing their unit costs and the wind & solar will incur additional capital costs and increased emissions from mining, processing and manufacture of wind & solar.

A Higher Nuclear Case (40% nuclear plus 16% gas, 8% hydro & 37% solar)

This case increases nuclear power generation while reducing gas and maintaining hydro outputs to further reduce emissions. The increased capital cost relative to the previous case of 40% nuclear needs to be traded off against the potential for emissions reductions.