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Submission on the

2026 Draft AEMO Integrated System Plan

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- Download the EPC submission on the Draft 2024 ISP at https://www.epc.com.au/wp-content/uploads/EPC-Submission-on-the-2026-Draft-ISP-20240216-Final.pdf
- Download the EPC submission on the Draft 2022 ISP at https://www.epc.com.au/wp-content/uploads/EPC-Submission-on-the-2022-Draft-ISP-20220211-Final.pdf
- Download the EPC supplementary submission on the 2022 ISP at https://www.epc.com.au/wp-content/uploads/EPC_Supplementary_Response_to_ISP_Revision_1B_20220926.pdf

Disclaimer

1 Introduction

1.1 Electric Power Consulting Pty Ltd (EPC) welcomes the opportunity to participate in the consultation on the Draft 2026 Integrated Systems Plan (ISP). The ISP outlines a set of ambitious scenario pathways for the energy transition to Net Zero by 2050.

1.2 EPC acknowledges the scale and complexity of the task at hand. The Draft 2026 ISP addresses issues that will have a large bearing on the future development and prosperity of Australia. For this reason, we are keen to contribute to making the ISP a better plan.

2 About Electric Power Consulting Pty Ltd

2.1 Electric Power Consulting Pty Ltd is a consulting electrical engineering firm that was formed in 1990 by its owner and Director Dr Robert Barr. Dr Barr is a visiting professorial fellow at the University of Wollongong. EPC has special skills in electric power system analysis and has been providing consulting services to Network Service Providers, high voltage (HV) customers, large low voltage (LV) customers, universities and governments across Australia and overseas for over 40 years.

2.2 Of special interest to EPC is the topic of Distribution Network Planning. EPC has provided a full 13 week Distribution Network Planning module for the University of Wollongong in the "Master of Power Engineering" course that has been completed by many post graduate students over the past decade. In preparing this submission, we have been able to employ many of the most fundamental principles needed to successfully plan a Power System for the future. These skills include both technical and financial analysis.

2.3 EPC has special modelling tools that allow direct comparison with the ISP modelling. Much of this report is about comparison of AEMO power and energy modelling with EPC modelling.

2.4 We have not addressed issues of system strength, stability or inertia. These issues are very important but are beyond the scope of this report.

3 List of Abbreviations

Abbreviation	Description
AEMO	Australian Energy Market Operator
EPC	Electric Power Consulting Pty Ltd
ISP	Integrated System Plan
MW	Mega Watt (unit of power)
MWh	Mega Watt Hour (unit of energy)
NEM	National Electricity Market
NPV	Net Present Value
OCG	Open Cycle Gas (generator)
PV	Photo Voltaic
t/MWh	tonnes/MWh (unit of CO_2 emissions)
TNSP	Transmission Network Service Provider
WACC	Weighted Average Cost of Capital

4 Overview of AEMO Draft 2026 Integrated System Plan

4.1 The ISP's purpose is to "..set out the least-cost investment pathway for the National Electricity Market (NEM) to meet consumer energy needs and government policies through to 2050". The key questions addressed in this EPC submission is whether this purpose has been achieved and how might the draft ISP be improved to better achieve this purpose.

4.2 In preparing this response to the draft ISP, we have limited our scope to key areas that go to the heart of purpose of the ISP. These issues are:

a) The technical viability of the mix of transmission, generation and storage specified in each of the scenarios to meet the specified customer loads.

b) The quality of financial analysis and the identification of areas where improvements can be made.

c) The projected impacts on electricity customers.

4.3 Our efforts have focused on the AEMO Step Change Scenario because it is the most advocated scenario.

5 The Planning Process

5.1 The planning process by its very nature is iterative. It is always difficult to look even a few years forward, let alone 24 years forward to 2050. The net zero requirement dictated by various government policies is obviously a key constraint as the NEM plan evolves. We do not expect perfection, as we know that is not possible. We do however expect the ISP to:

a) incorporate the basic engineering condition of generation/load balance at all times.

b) provide comparisons of delivered energy costs to customers on at least an annual basis from now through to 2050 for each scenario.

c) allow a comparison of delivered energy costs between scenarios and with existing electricity costs.

d) provide sufficient detail of each scenario for third parties like EPC to fully understand both the engineering and the financial inputs and outputs of all the scenarios.

e) provide for a wide range of random variability in renewable energy output, especially wind and solar PV, including:

   i. periods of wind drought,
   ii. periods of low solar radiance,
   iii. periods of low hydro storage (rain drought and preceding use),
   iv. periods of low pump storage reserves and
   v. periods where the NEM is exposed to simultaneous combinations of the above.

f) provide a reasonable safety margin between generation and load at all times. This will include:
   i. adequate reserves of dispatchable generation; and
   ii. adequate reserves of stored energy.

5.2 The worst case conditions that a scenario needs to ride through will be different for each scenario and will be dependent on the specific generation and storage mixes.

5.3 In our view the existing 2026 draft ISP has not delivered what is needed in these key areas. Each of these key points are addressed in this submission.

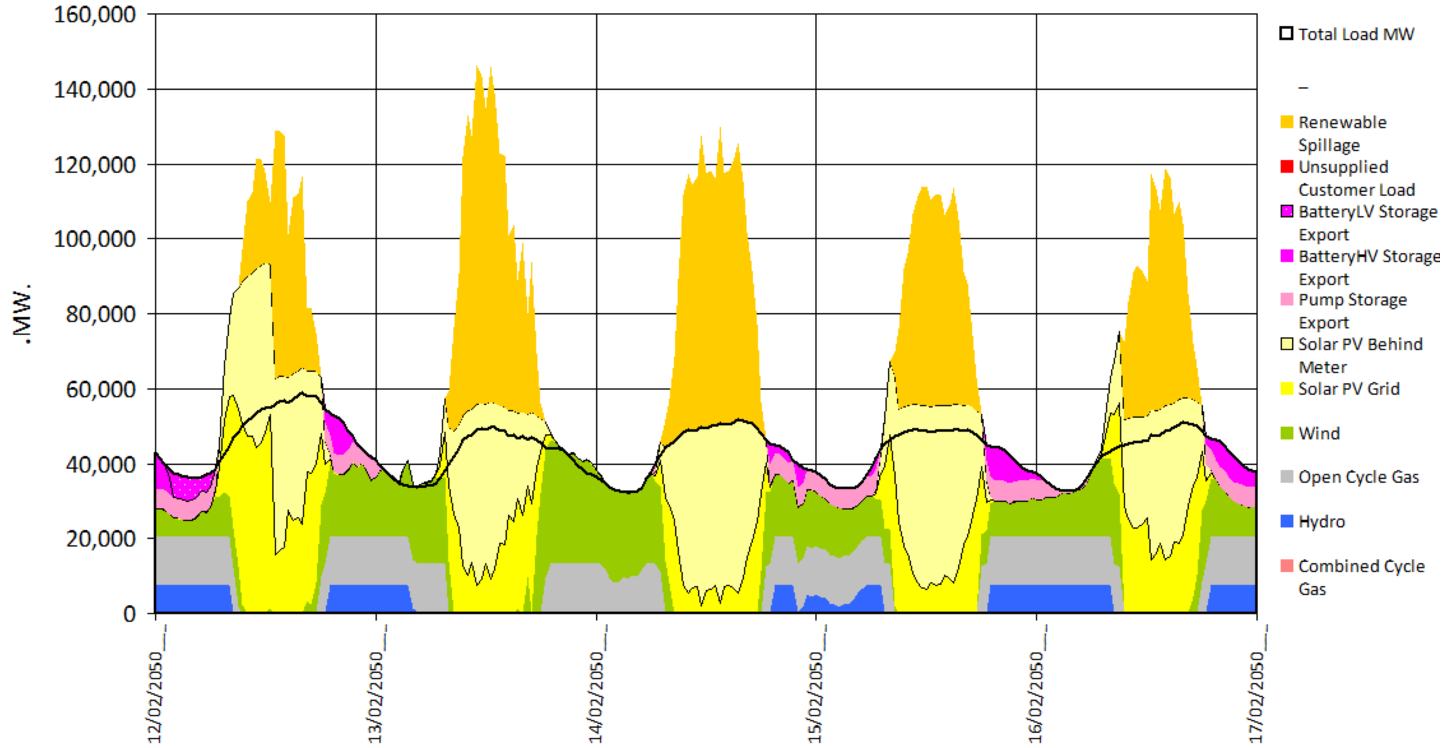
6 The Step Change Scenario

6.1 Modelled Generation Profiles

6.1.1 As planners, when we look at network or system plans like the ISP, we focus on the end year which in this case is 2050. The transmission build, generation mix, the energy storage mix is the input to the plan that delivers the nominated 2050 load at the required level of carbon emissions, reliability and cost. All the preceding years of the plan are stepping stones on how the plan is executed.

6.1.2 The AEMO projected 2050 generation mix and nominated MWh load/generation output was entered into the EPC NEM model to review its performance and characteristics. The load profile shape, MW wind patterns, and MW solar PV patterns were based on historical performance of the NEM from the years 2017, 2018 and 2019. Figure 1 shows EPC NEM model dispatch of generation, pump storage, HV battery storage and LV battery storage for a period in Summer 2050. With abundant solar PV, wind and storage, the dispatch is successful in fully meeting the needs of all customer loads. A high level of renewable spillage/curtailment is evident. This renewable curtailment is potential generation from wind and solar PV that cannot be utilised because there is no load or storage able to utilise it.

Figure 1 – Step Change Scenario – EPC Model Summer Projected 2050 Generation Profile



6.1.3 Figure 2 shows the EPC NEM model dispatch during part of June 2050 during a credible low in solar PV availability (winter and overcast) and a wind drought across Southeast Australia. These modelled conditions are based on actual conditions that occurred in June 2017. What is evident here is that the NEM's stored energy reserves have been exhausted and over 20,000 MW of load has been shed. This is an unacceptable reliability outcome showing that the EPC modelled NEM has insufficient generation and storage. Table 1 shows that

0.36% of the customer load energy remains unsupplied in the year 2050. Major supply outages were experienced across 17 days of the year. In addition, the carbon emissions of 0.13 t/MWh for fuel only and 0.20 t/MWh for fuel and embedded emissions were inconsistent with a Net Zero requirement. The contrast between the EPC NEM modelling and the AEMO ISP modelling is very stark.

Figure 2 – Step Change Scenario – EPC Model of Projected June 2050 Generation Profile Showing Unsupplied Load

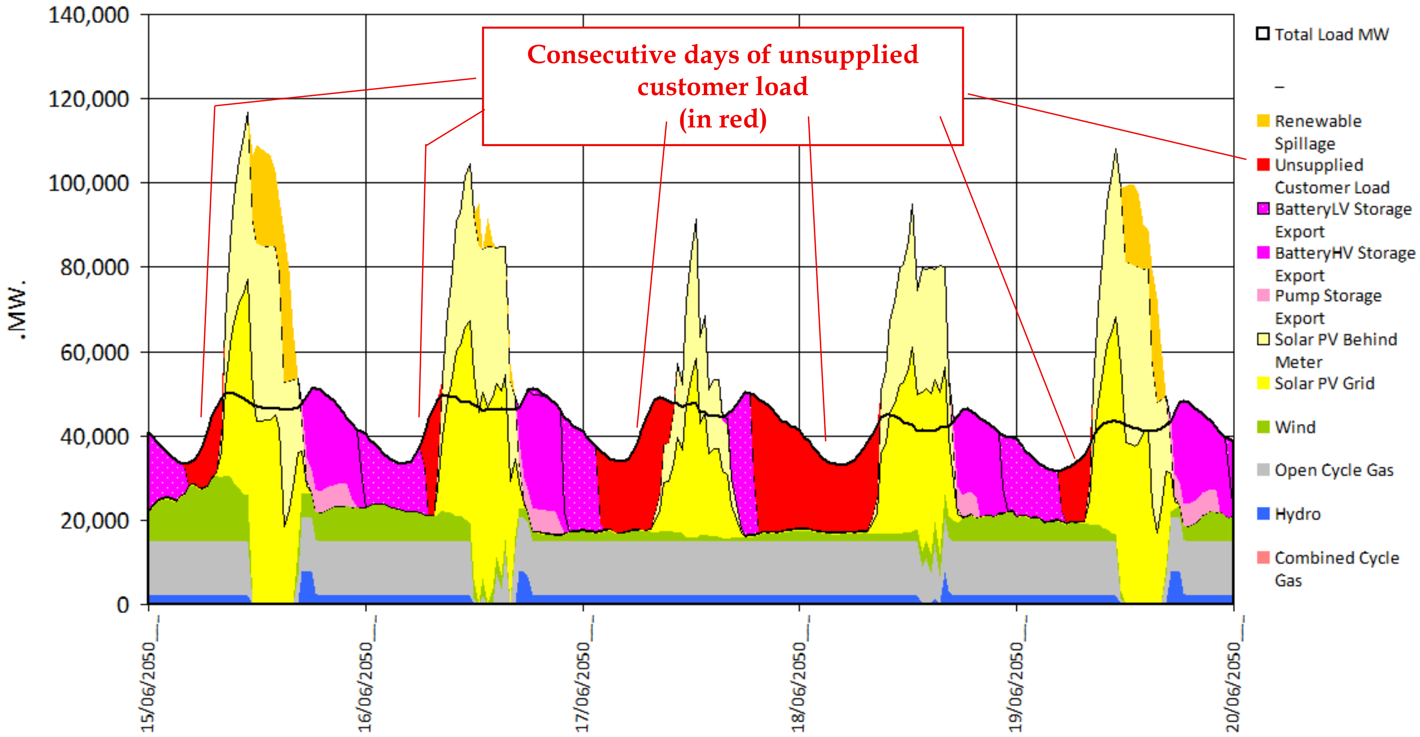


Table 1 – Statistical Measures of Performance – 2050 Step Change Scenario

Year	AEMO Scenario	Generation - Load Energy TWh	% Load Reduction on the 362 TWh AEMO 2050 forecast	EPC Modelled Emissions		EPC Model Results		
				Fuel Only t/MWh	Fuel and Embedded t/MWh	Unsupplied Load - % of total load MWhs	Supplied Load - % of total load MWhs	Days/year impacted by Unsupplied Load
2050	Step Change	362 (see note 1)	0.0%	0.13	0.20	0.36%	99.64%	14.4
2050	Step Change	285 (see note 2)	21.3%	0.12	0.21	0.00%	100.0%	0
2050	Step Change	258 (see note 3)	28.8%	0.01	0.10	0.00%	100.0%	0

Note 1 - Full AEMO Forecast Load
Note 2 - Load reduced in EPC model to provide zero unsupplied load
Note 3 - Load reduced in EPC model further to provide low carbon emissions

6.2 **Carbon Emissions**

6.2.1 The EPC model assesses carbon emissions on both a fuel only basis and a combined fuel and embedded emissions basis. Embedded emissions relate to emissions that were created during generator/battery manufacture and installation. Embedded emissions assessments have been based on the United Nations Economic Commission for Europe assessment provided in Appendix 1.

6.2.2 Table 1 provides a summary of the modelled carbon emissions for the 2050 Step Change Scenario under loading conditions of 362, 285 and 258 TWh. Where embedded emissions are taken into account, the best emissions outcome of 0.10 t/MWh was achieved at a reduced 2050 load of 258 TWh. This level of emissions is considered suboptimal and:

a) reflects the high materials intensity that underpins the Step Change Scenario.

b) does not provide an emissions reduction benefit commensurate with the high cost of implementing the Step Change Scenario.

c) fails to achieve ultra-low emission levels.

6.3 **Dunkelflaute Events**

6.4 Dunkelflaute events present the most challenging conditions for any Wind/Solar PV based power system. Expectations are that under worst case conditions, there would be preceding rain drought conditions impacting hydro generation and pump storage and real time rain/overcast conditions impacting solar PV outputs.

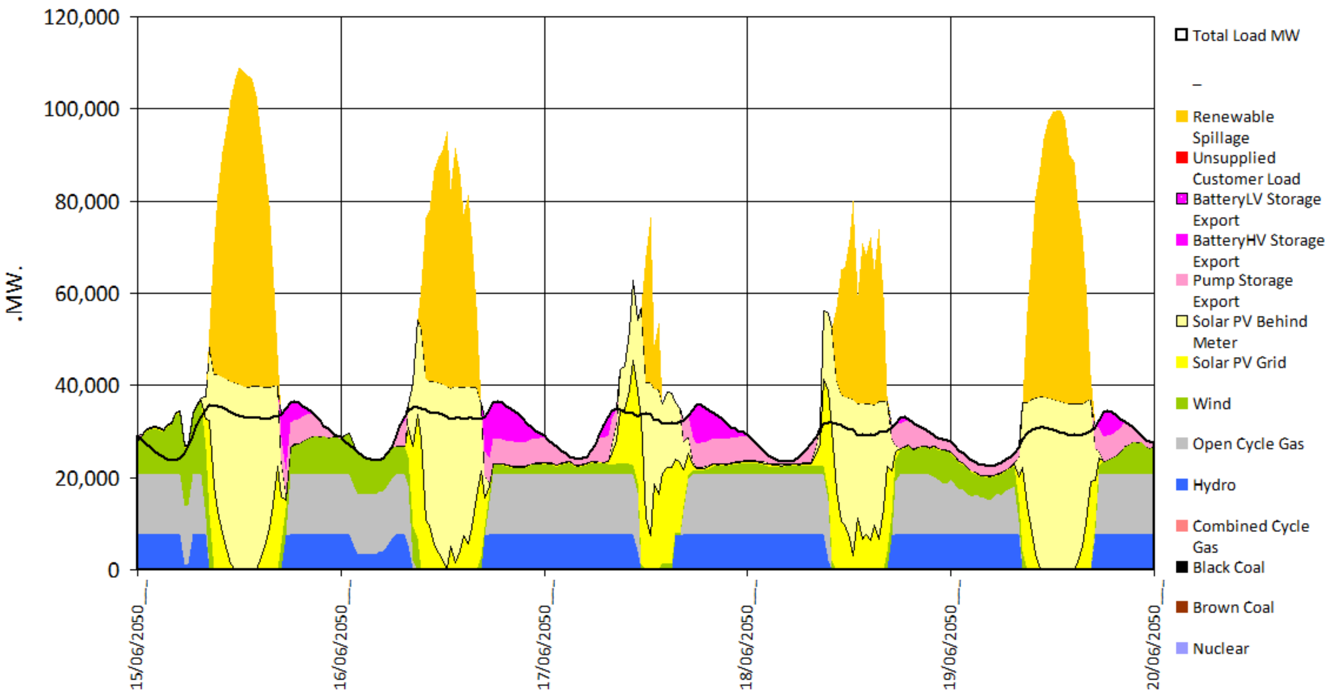
6.4.1 Our conclusion is that the 2026 Draft ISP has most likely not addressed the full simultaneous set worst case conditions that needs to be considered to provide the necessary levels of power system reliability.

6.4.2 It is suspected that in the 2026 ISP and previous ISP's, group wind power output may have been overestimated at times of Dunkelflaute conditions. This is a significant risk if wind traces based on NASA satellite data are used for the simultaneous estimation of MW wind farm outputs across all the NEM regions.

6.5 **Evaluation of Generation and Storage Resources**

6.5.1 The question then addressed by the EPC modelling was how much load reduction is required to be able to match supply and demand over the full 2050 year. Table 1 shows that forecast load needs to be reduced by 21.3% to eliminate power supply interruptions over the three year modelling period. Figure 3 and Table 1 show that to reach a low emissions operating state, a further load reduction down to 297 TWh (29% lower than the AEMO load forecast) is required.

Figure 3 – Step Change Scenario – EPC Model of June 2050 - EPC Model Generation and Storage Resource with the 2050 Load Reduced to 297 TWh



6.6 Figure 3 shows the EPC load profile during a critical winter period where there is just sufficient generation to meet customer loads.

6.7 As an alternative to reducing the customer load, to make the model operate without power outages, the AEMO nominated MW generation and MW/MWh storage resources need to be increased by 27% to supply the AEMO forecast load.

6.8 Delivered Cost of Electricity to LV Customers

6.8.1 Generation Network and Storage Cost Components

6.8.1.1 EPC modelling shows that when the NEM is dominated by Variable Renewable Generation and Storage, it is difficult and very expensive to supply that last component of load during the most severe wind drought and low solar PV output conditions.

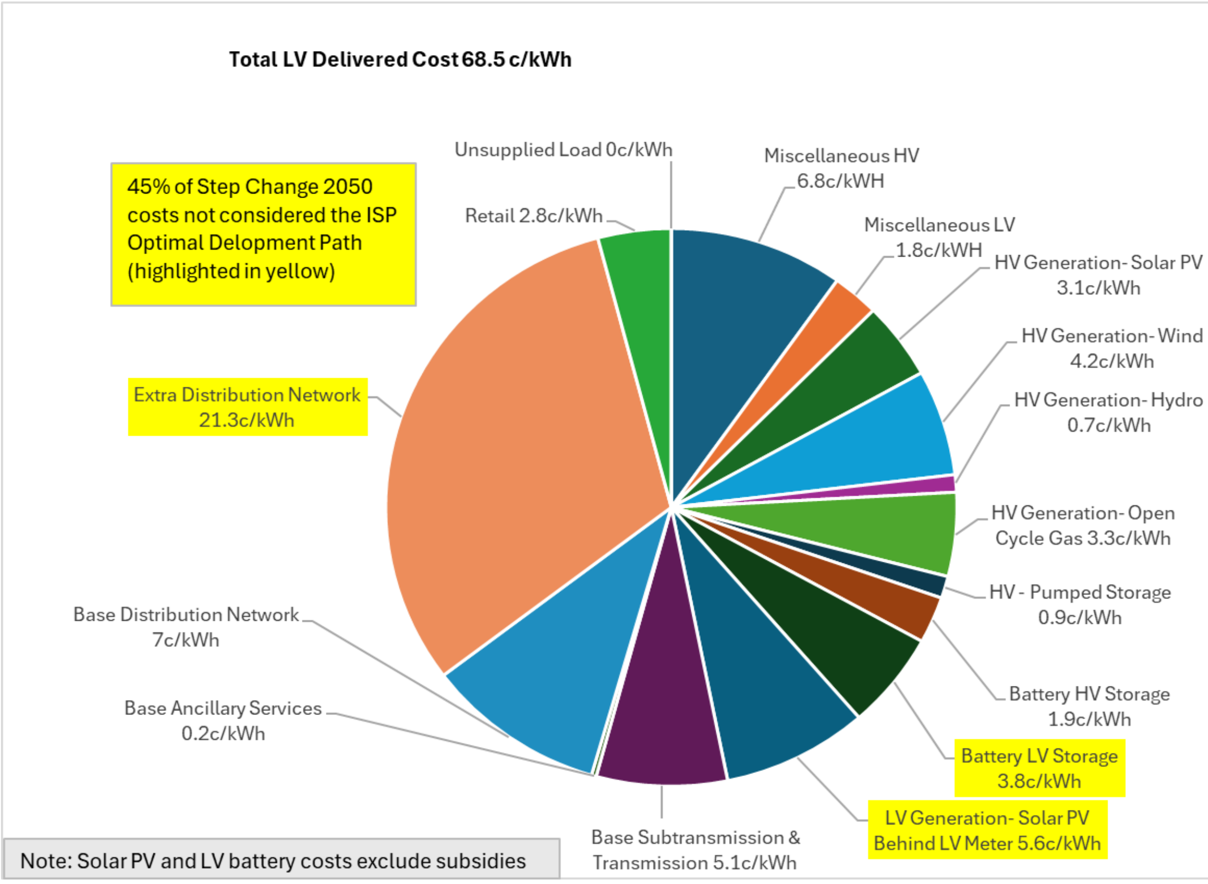
6.8.1.2 The AEMO ISP has made no attempt to assess the delivered cost of electricity to either HV or LV customers. This is a major deficiency of the ISP that is preventing serious viable plans being explored and considered. The EPC model provides a "relative" delivered cost of electricity to both HV and LV customers. The costs are relative in the sense that they are based on a 2024 cost base (for a 2050 plan) and they are comparable between alternate model runs.

6.8.1.3 Figure 4 shows the EPC model cost components under a 285 TWh Step Change scenario. The cost components include all the costs necessary to provide an electricity service to LV customers. Included is the generation, storage and network costs including all distribution costs and behind the meter solar PV and batteries.

6.8.1.4 The cost categories highlighted yellow in Figure 4 have not been fully considered by AEMO in the ODP of the ISP. These costs represent 45% of the total delivered costs to LV customers. The uncosted NEM components make it impossible for AEMO to optimise the development of the NEM in terms of technical performance and cost.

6.8.1.5 Claims that the ISP is *"the least-cost investment pathway for the National Electricity Market (NEM) to meet consumer energy needs and government policies through to 2050"* cannot be justified because approximately 45% of the electricity costs have not been properly considered. The EPC analysis shows that the Step Change Scenario is a very high cost scenario where a large part of the cost has been pushed down into the distribution network and customer installations, where it is not adequately assessed.

Figure 4 – 285 TWh Step Change Scenario– EPC Model of Delivered Cost to LV Customers



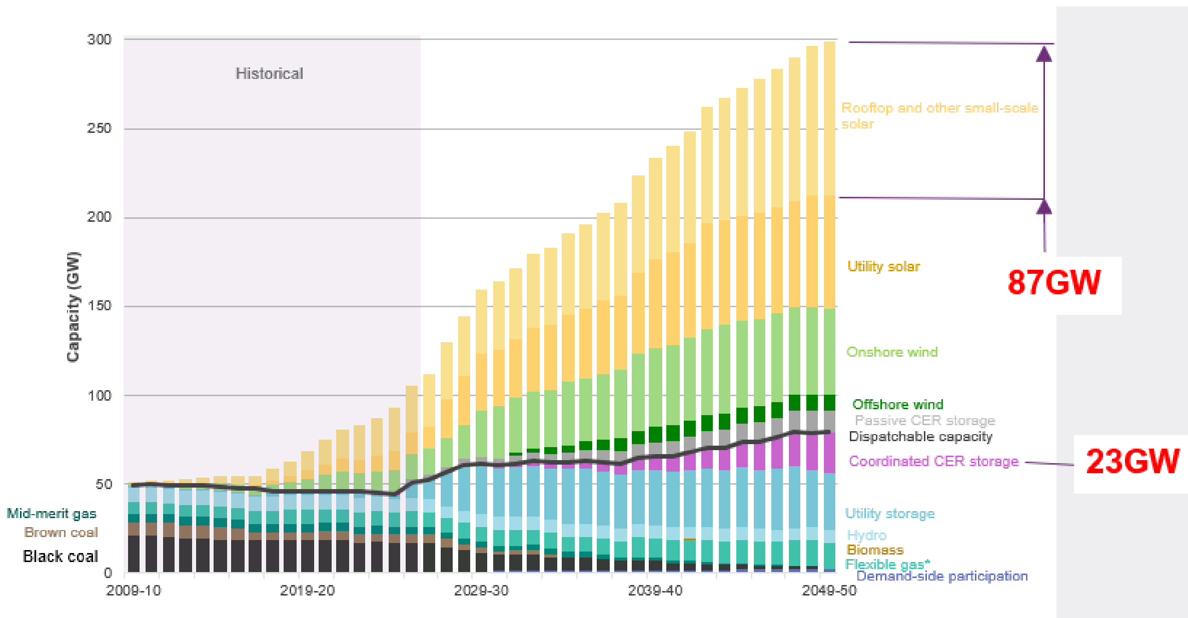
6.8.2 Cost Imposts on Small LV Customers

6.8.2.1 Figure 5 from the ISP shows in 2050 the Step Change Scenario requires 87 GW of roof top solar PV and 23 GW of behind the meter batteries. These are very large numbers that need to be carefully considered.

6.8.2.2 Based on quantities provided in the Step Change ISP and EPC estimations of future customer numbers, Table 2 provides an analysis of the required "averaged" investment each suitable LV customer is expected to make in roof top solar PV generation and battery storage. It shows that an average customer that is able to install solar PV and batteries will need to install 11.9kW of solar PV, 13.8 kWhs of behind the meter battery at a combined cost of $32,930. This is a large impost for items that are expected to have a life of about 15 years. Ownership depreciation cost would be $2,195 p.a. on top of maintenance and operating costs. Adding interest and maintenance costs would bring the total to approximately $4,171 p.a.. Many houses will not have the suitable north and west facing roof area to allow installation of the required PV panels in an efficient manner.

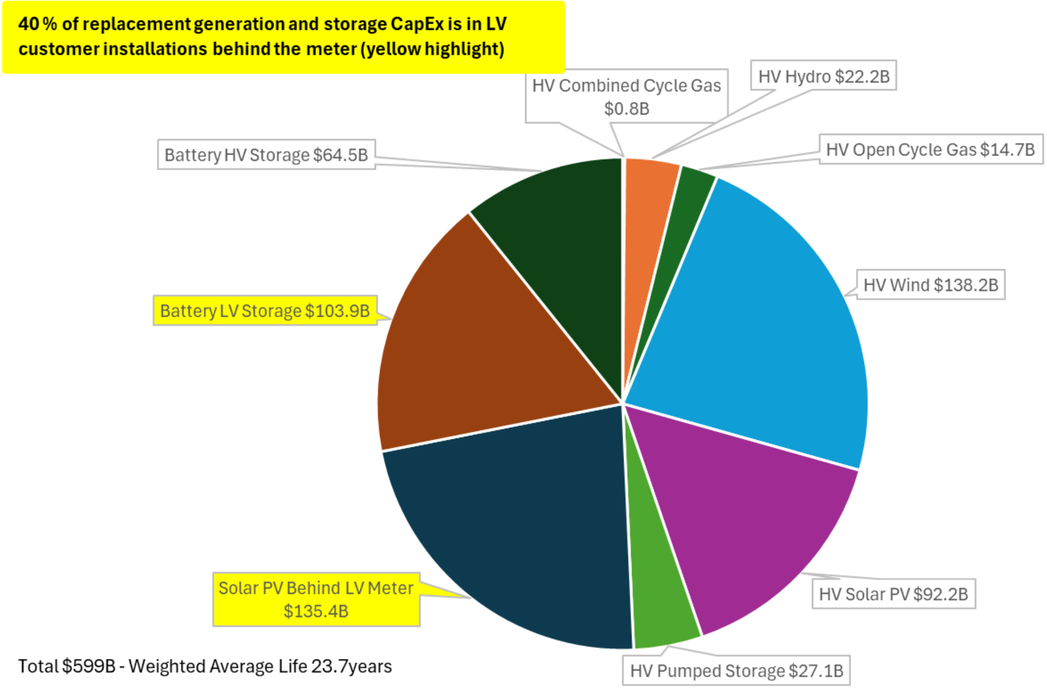
6.8.2.3 In addition to high customer costs, reliance on consumer grade solar PV panels, inverters, batteries, Wi-Fi, GSM, internet communications and cyber protections will present major challenges to providing reliable and secure power system operations.

Figure 5 – Step Change Scenario – GW Generator and Storage Capacity Plan



6.8.2.4 Under EPC modelling, 2050 Step Change Scenario has the Generation/Storage Replacement CapEx values as provided in Figure 6. The generation/storage assets have a total replacement value of $599B with a weighted average life of 23.9 years. Of significance is that 40% of this value is reliant on customer investments on roof top solar PV and behind the meter batteries (highlighted in yellow). These are exceptionally high investments that need to be emphasised in the ISP reports. Although much of the roof top solar PV and behind the meter batteries are subsidised, the subsidy is being paid by other customers and needs to be included in the analysis.

Figure 6 – 339 TWh Step Change Scenario 2050 – Replacement CapEx for all Generation and Storage Types



6.8.3 Cost and Loading Imposts on LV and MV Distribution Networks

6.8.3.1 The planned quantity of roof top solar PV required under the Step Change Scenario will place enormous stress on the distribution LV and MV networks. There will be times when localised groups of customers on masse will need to export most of about 7kW of roof top solar PV to reach the overall performance requirements of the Step Change scenario.

6.8.3.2 Existing distribution networks were never designed to accommodate this level of export. Old networks were typically designed for an After Diversity Maximum Demand (ADMD) of 3-5 kVA/customer import while newer subdivisions are higher at about 7kVA /customer. Most LV networks will require major augmentation to be able to operate over a range of say 6 kVA/customer import to 8kVA /customer export. A photograph of a typical overhead LV network in an urban subdivision is shown in Figure 7. This LV network is one of many hundreds of thousands of similar networks across the NEM. Many of these LV networks are underground.

Table 2 – 2050 Step Change Scenario - Estimation of LV Customer Investment Required in Solar PV and Behind the Meter Batteries

2050 ISP Step Change item	Quantity	Units
Estimated NEM LV customers (homes & small business)	9,366,744	customers in 2024
Estimated standalone houses	70%	
Estimated customer increase to 2050	38%	
Assumed houses suitable for solar PV and batteries due to tress, roof size and orientation etc	80%	
Estimated installations suitable for roof top solar PV in 2050	7,269,230	customers in 2050
Total rooftop solar PV required	86,656	MW in 2050
Total behind the meter battery storage required	99,960.0	MWh in 2050
Total behind the meter battery capacity required	35,255	MW in 2050
Average rooftop solar PV required	11.9	kW/customer in 2050
Average behind the meter customer battery energy required	13.8	kWh/customer in 2050
Average behind the meter customer battery energy required	4.8	kW battery inverter
Average rooftop solar PV cost	$18,632	/customer in 2050 #
Average behind the meter battery cost	$14,298	/customer in 2050 #
Average combined rooftop solar PV and battery cost	$32,930	/customer in 2050 #
Annual depreciation based on 15 year battery and Solar PV life	$2,195	/customer/year
Interest finance cost @ 4% p.a.	$1,317	/customer/year
Estimated Maintenance Cost @ 2% of CapEx p.a.	$659	/customer/year
Total Ownership Costs	$4,171	/customer/year
# Note - based on 2024 costs excluding subsidies		

6.8.3.3 Existing distribution networks were never designed to accommodate this level of export. Old networks were typically designed for an After Diversity Maximum Demand (ADMD) of 3-5 kVA/customer import while newer subdivisions are higher at about 7kVA /customer. Most LV networks will require major augmentation to be able to operate over a range of say 6 kVA/customer import to 8kVA /customer export. A photograph of a typical overhead LV network in an urban subdivision is shown in Figure 7. This LV network is one of many hundreds of thousands of similar networks across the NEM. Many of these LV networks are underground.

Figure 7 – Typical LV Network that will Require Major Augmentation/Rebuild under the Step Change Scenario (2050)

6.8.3.4 The main design limit in residential suburban LV networks is voltage drop during periods of peak customer load import and voltage rise at times of peak solar PV export. Most existing LV networks will require major augmentation/rebuilding to cater for the combination of customer load and solar PV export required by the Step Change Scenario (2050). Brown field augmentation/rebuilding is an extremely expensive process, particularly in subdivisions with underground reticulation. It is possible to spend a million dollars on such work and augment the supply to as few as 100 customers.

6.8.3.5 To their credit, AEMO have for the first time considered distribution costs in their analysis. This will include LV network costs. It is noted that the ISP states that *"Relatively small investments in the distribution networks would support that CER"*. While this statement is partially correct, EPC modelling of distribution networks over many years comes to the opposite conclusion.

6.8.3.6 When CER levels are low, relative to customer loads, the existing LV networks can easily accommodate customer exports. Low cost resetting of distribution transformer taps in coordination with lowering MV float voltages can give the LV and MV networks more capability to deliver reverse power flows. In some networks this can readily be achieved but in other networks it can be near impossible due to historic choices made for transformer tapping ranges at times when reverse power flows were not an issue. Where the solar PV exports become equal to or larger than the design customer loads, no amount of "fine tuning" will solve the voltage drop/rise problems. Major and very expense network augmentation will be required. In the final ISP, to accommodate this issue one of the following strategies needs to be applied. The options are:

a) To gain the full benefit of 87MW of roof top solar PV generation and battery investment, a much larger LV and MV distribution CapEx needs to be allocated in the Step Change scenario.

or

b) If the LV/MV CapEx is kept to "*Relatively small investments*" as stated in the Step Change scenario, the MW output modelling of the rooftop solar PV needs to be curtailed to levels that can be accommodated by the LV and MV networks.

or

c) Some combination of a) and b).

6.8.3.7 Option a) will require a major boost in LV/MV distribution investment that has not been included in the AEMO Step Change scenario. Option b) will requires large additional investments in HV grid renewables or other generation and transmission to compensate for the curtailed rooftop solar PV output.

6.8.3.8 Distribution network companies are already having difficulty accommodating large reverse power flows in parts of their networks. These are very serious issues that AEMO need to address in its final ISP and in future ISPs.

6.8.3.9 Appendix 2 provides technical details of the type of voltage drop/rise effects that need to be addressed to implement the Step Change Scenario (2050).

7 Review of AEMO Economic Evaluations

7.1 The ISP NPV costing of scenarios used by AEMO is useful for comparing variations in generation mixes and transmission development pathways within the confines of a set loads and other constraints within a scenario. Because each scenario has a different set of constraints, individual scenario NPV values are not comparable between scenarios. This in our view is a major weakness that needs to be addressed in the final ISP.

7.2 The ISP economic methodology and results are very poor in conveying to industry, government and customers the impact on future delivered electricity costs to customers.

7.3 Failure of AEMO to consider behind the meter costs of solar PV and battery storage is a clear indication of the limitation of the existing ISP scenario financial analysis. If the aim is only to examine transmission options and HV connected generation mixes, this approach may be reasonable. However, in our view the ISP needs to do much more to be useful to its stakeholders.

7.4 It is our view the costs associated with augmentation of LV systems, MV systems and subtransmission systems need to be fully addressed. The focus of the ISP needs to extend to include all costs, including behind the meter solar PV and battery costs because they form such an integral part of the ISP scenarios. A direct consequence of this approach is that the ISP provides no guidance on which scenarios provide the best outcome for customers.

7.5 It is our view that the ISP financial analysis needs to go beyond what has been provided in the draft ISP. The ISP aim should be to minimise the total cost of electricity supply to customers, not just to minimise the NPV cost of transmission, HV generation, HV grid storage and selected other items. The scope of the electricity costs needs to include:

- Grid connected generation (both DNSP and TNSP).
- Transmission.
- Grid connected storage (both DNSP and TNSP).
- All subtransmission (both conventional load and REZ developments).
- All LV and MV distribution.
- All behind the meter generation and battery storage.
- Retail and metering.

7.6 The ISP needs to become more customer focused and show comparable HV and LV customer delivered costs in $/MWh for each year through to 2050 for all the scenarios. These costs could be based on 2026 prices. All scenario costs and NPVs need to be on a common base so that they can be directly compared. Without this detail, the ISP is delivering only part of what it is capable of, and the public is not getting value for the investment made in developing the ISP.

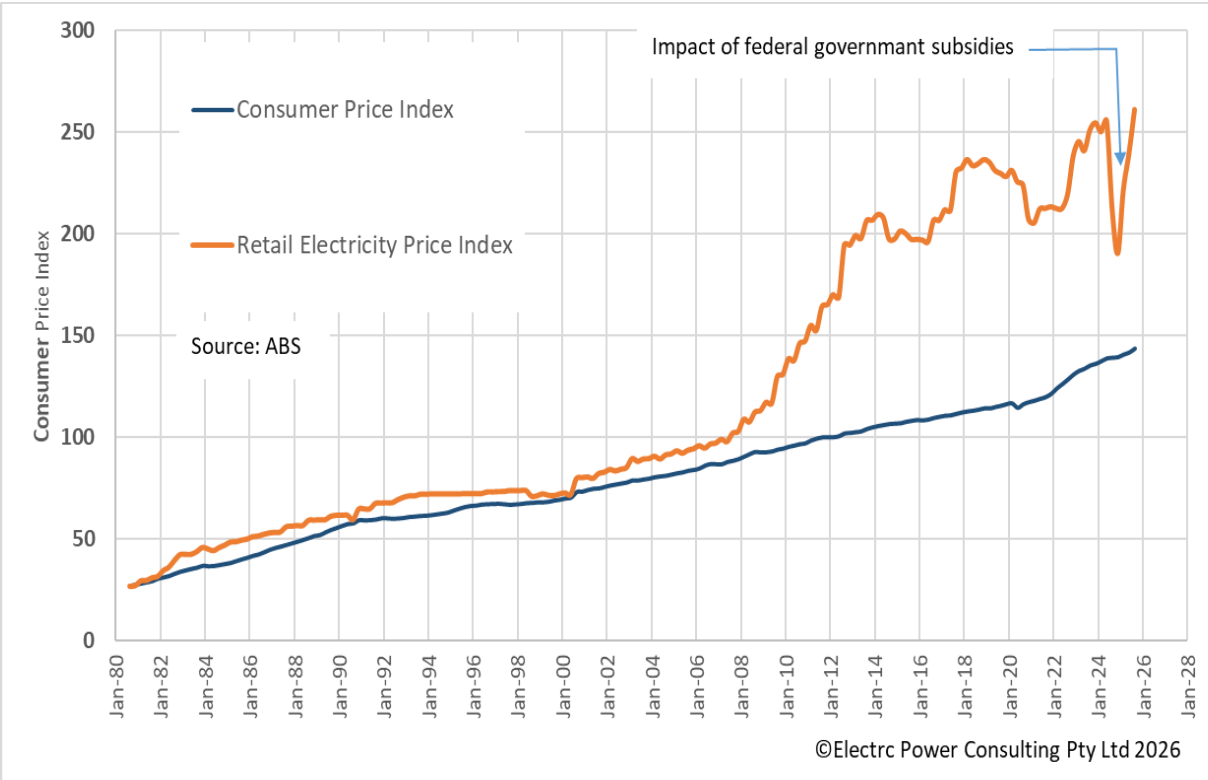
7.7 Most of the data needed to complete this task is readily available from the work already undertaken on the draft ISP. The balance of information needed is available in the public domain or via the AER. EPC can provide assistance in defining a suitable methodology.

7.8 In the NEM, electricity supply costs are driven by investments by generators, TNSPs, DNSPs, Retailers, Meter Service Providers and customers. For customers, the supply cost contribution is mostly by way of rooftop solar PV and small-scale battery storage. The aim should be to build ISP scenarios to assess and minimise the total ongoing delivered costs of energy. Small scale behind the meter solar PV and battery storage needs to be treated as just another NEM resource. If AEMO can achieve this objective, it will provide a very valuable community service and open up a new informed conversation on the best way forward having regard to a wider range of possible NEM scenarios.

8 Historic Retail Electricity Prices

8.1 The failure of the electricity industry to maintain or lower the real price of residential electricity is illustrated in Figure 8. Figure 8 shows that electricity price growth has accelerated well beyond the Consumer Price Index (CPI) since 2009. The effect of temporary relief from federal government subsidies are evident in 2025.

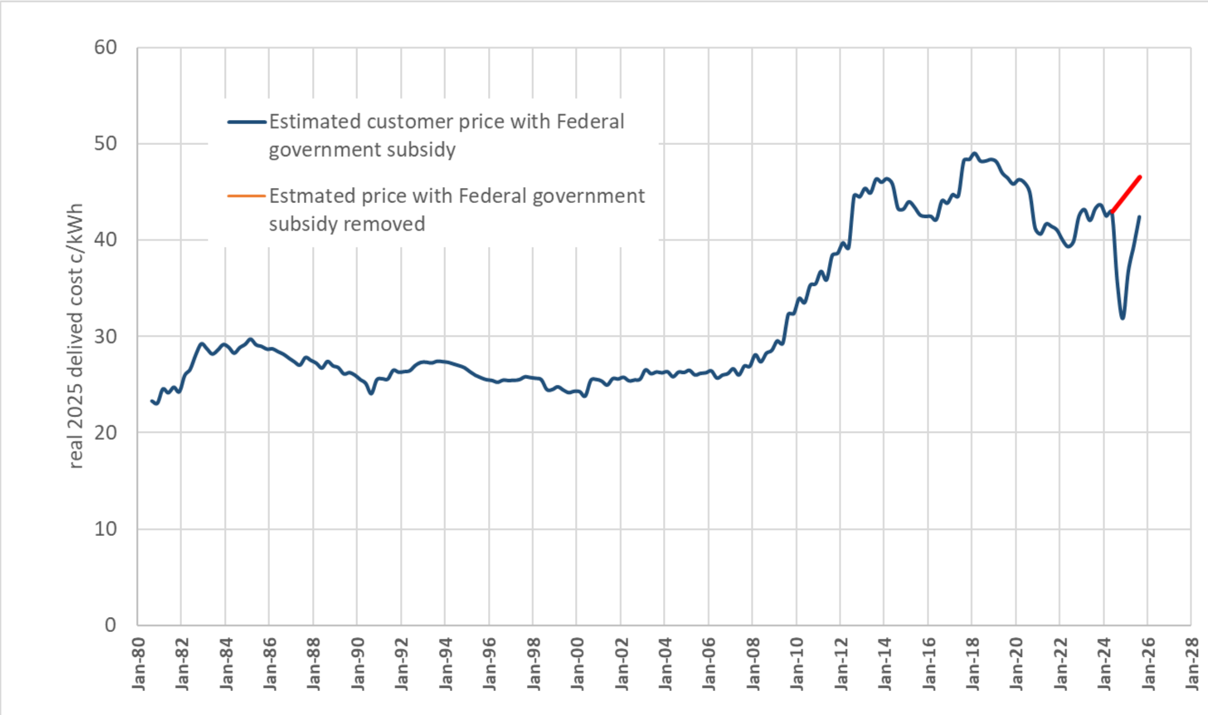
Figure 8 – Retail electricity price index and consumer price index 1998 to September 2025



8.2 Figure 9 shows real price estimates based on 2025 prices and the indexes provided in Figure 8. It is based on a current 2025 price set at 42.3 c/kWh. Figure 8 shows that prices in early by prices as low as 25-30 c/kWh were achieved in the years 1980 to 2009.

Figure 9 – Real residential electricity prices 1998 to September 2025

8.3



9 New Electricity Price Targets

9.1 Figure 8 and Figure 9 highlights one of the major failures of the Australian electricity industry over the last 20 years that is leading to major customer dissatisfaction. Unless cost issues can be addresses, the social licence for any sort of transition will be lost.

9.2 Figure 9 provides evidence that the Australian electricity industry is capable of delivering electricity prices below 30c/kWh (in 2025 prices).The challenge for governments, AEMO and the electricity industry to drive down electricity process for the benefit of customers to the levels that have applied in the past. In the view of EPC, a delivered price of electricity below 30c/kWh (in 2025 prices) is an achievable outcome.

9.3 In the view of EPC, the current step charge scenario of the ISP is much more likely to increase residential electricity prices rather than result in price falls. EPC would like to see priority 10-20 year targets set for lower electricity prices.

10 Request for Additional Scenario Data

10.1 To demonstrate the credibility of each of the scenarios, it is recommended that the additional information covering customer energy use, capacity factors, storage performance, environmental performance and reliability of supply as detailed in Appendix 3 be included in the ISP spreadsheets.

11 Conclusions

11.1 Differences in all the scenario outcomes between the AEMO modelling and the EPC modelling are very significant and cannot be ignored. While the AEMO modelling presents a smooth transition to net zero emissions with no unsupplied load issues, the EPC modelling points to major reliability problems and emission levels well above what is expected by governments.

11.2 The differences in modelling outcomes will come down to the underlying assumptions, model inputs and methodologies. It is our view that there is much to be gained for the Australian community if the causes of the differences in modelling outcomes can be identified. Identifying these differences is the key to building a stronger more robust plan for the future.

11.3 Extreme periods of wind drought, low solar radiance (dunkelflaute events) and other events need to be very well understood because they a key driver in determining the required investment levels in power systems dominated by variable renewables. It is suspected that there are significant weaknesses in this area that need to be addressed in the ISP.

11.4 The existing ISP NPV financial analysis is very transmission centric and needs to be broadened to include amongst many other categories, behind the meter generation and battery storage assets. There is a large need to make the ISP more customer focused.

11.5 Over reliance on uncosted consumer grade consumer grade solar PV panels, inverters, batteries, Wi-Fi, internet communications and cyber protections within ISP scenarios will present major challenges to providing reliable and secure power system operations.

11.6 The ISP scenarios make extensive use of the following electrical components yet fails to include their costs in their analysis:

a) behind the meter solar PV.
b) behind the meter LV batteries.

11.7 Although addressed for the first time in this ISP, the following items have not been addressed sufficiently to provide reasonable cost inclusions in the ISP.

c) LV networks.
d) MV networks.

11.8 The AEMO costing methodology is a very major concern that renders the ISP highly deficient and brings the claim that *"AEMO continues to find that renewable energy connected with transmission and distribution, firmed with storage and backed up by gas is the least cost way to supply electricity to homes and businesses through to 2050, as coal plants retire and while meeting government policies."* into question.

11.9 The EPC analysis shows that the Step Change Scenario is a very expensive scheme that will require a major rebuild of the distribution network. Far from being a low cost supply scenario, the EPC analysis shows that when all the costs are considered it is one of the most expensive schemes that could be devised.

11.10 In the view of EPC, the Step Change Scenario has no long term future as it progresses through to 2050. EPC modelling shows it will progressively provide more expensive electricity for customers and will struggle to maintain reliability and security of supply. In our view, AEMO predicted emissions reductions and forecast increasing customer load supply capabilities will not materialise as proposed.

11.11 It is our view that the trend of higher delivered electricity costs will continue a process of deindustrialisation and drive national productivity down across the economy. Large investments being made in transmission and renewable energy zones being called up by the ISP may well become stranded assets that will become a cost burden for electricity customers for decades to come.

11.12 In our view the AEMO have lost sight of the importance of the electricity customer. Rather than the grid providing an efficient electricity service to customers, the ISP is calling for electricity customers to make uneconomic investments beyond their level of final competency in solar PV and batteries to supply the grid. To make matters worse, the process will require a vastly augmented distribution networks that will have to funded by customers.

11.13 It is clear that AEMO feel bound by policies of governments. This gives AEMO some justification for the way the ISP has developed. The challenge for AEMO is to communicate to governments the cost consequences of delivering the ISP in accordance with their government policies and recommending better plans more in line with good engineering and delivering better outcomes for electricity customers.

12 Consultation Process

12.1 AEMO pride themselves on their extensive consultation, analysis and review. This document is the 3rd comprehensive ISP submission made by EPC.

Submissions were prepared by EPC for the 2022 and 2024 ISPs. Both submissions offered consultations with AEMO, none of which were taken up seriously by AEMO.

12.2 Hopefully this submission will generate enough interest with AEMO to warrant some serious consultation.

13 Recommendations

13.1 It is recommended that:

a) AEMO and EPC work closely in collaboration to identify the underlying causes of the differences in outcomes between the AEMO ISP models and the EPC models.

b) AEMO re-address their responses to the most extreme periods of wind drought, low solar radiance and other adverse conditions (dunkelflaute events).

c) The ISP financial reporting be enhanced to include all electricity supply costs including behind the meter solar PV and batteries, LV networks, MV networks and subtransmission systems.

d) The ISP financial reporting be enhanced to include HV and LV customer delivered costs in units of $/MWh for each scenario and for each year through to 2050.

e) The level of customer investments required in roof top solar PV and behind the meter batteries be made very clear under each ISP scenario and incorporated into the ODP.

f) AEMO explore more efficient and effective scenarios aimed at reducing the supply cost to HV and LV customers.

g) Additional data be provided in the scenario spreadsheets as detailed in Appendix 3.

Appendix 1 – UNECE Assessment of Embedded Carbon Emissions

Embedded carbon emissions have been estimated from figure 37 of the following UNECE report of 2021.

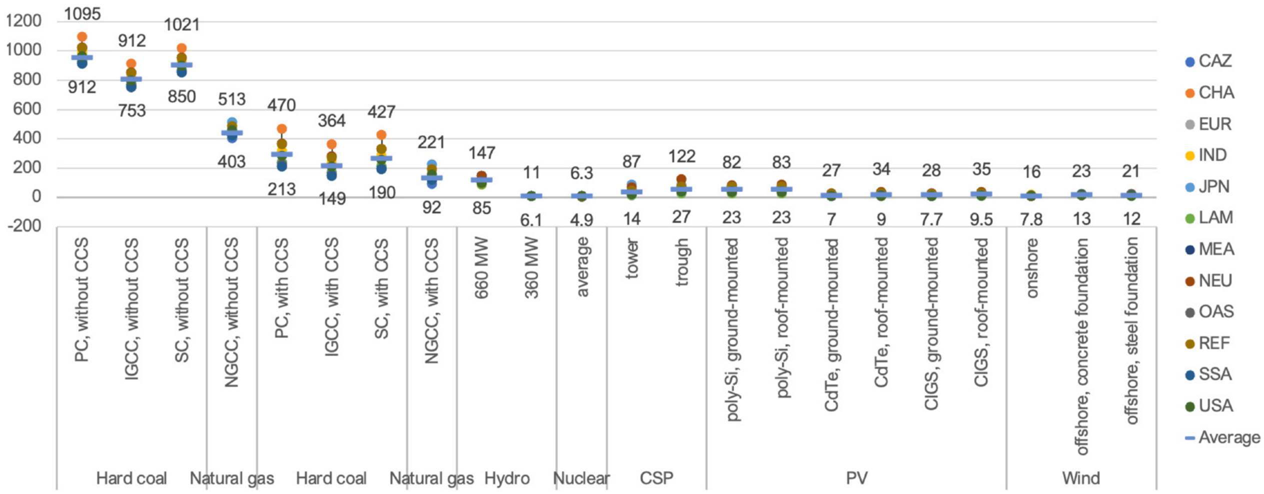
UNITED NATIONS ECONOMIC COMMISSION FOR EUROPE

Life Cycle Assessment of Electricity Generation Options

UNECE

Figure 37 Lifecycle greenhouse gas emissions' regional variations for year 2020. Variability is explained by several factors: electricity mix (all regions), methane leakage rates (fossil fuels), load factors (renewables). Nuclear power is modelled as a global average except for back-end.

Lifecycle GHG emissions, in g CO_2 eq. per kWh, regional variation, 2020



Appendix 2 – Solar PV Impacts on Distribution Networks

The following slides highlight the impact of high penetrations of rooftop solar PV on LV distribution networks. To accommodate the level of solar PV penetration in the Draft 2026 ISP (2050) most of these networks across the NEM will have to be rebuilt with much higher capacities.

Figure A4.1 shows a typical 11kV to 230/400V pole substation. This substation has two LV feeders supply houses in this street. The diagrams below show how voltages vary as LV feeders carry load and absorb solar PV generation. Ignoring the impact of batteries, supply voltages fall at nighttime when customers draw power from the grid. During optimum solar conditions, voltages rise as solar PV power exports are sent back to the substation.

Figure A4.1 - Low Voltage Distribution Network – Typical Suburban Street

Figure A4.2 shows how controls within solar PV inverters are used to curtail kW output when the supply voltage rises above 253V. When voltages rise above 253V, customer equipment is at risk of immediate damage or degradation leading to reduced life.

Figure A4.2 - Solar PV Inverter – Typical Setting/Characteristics

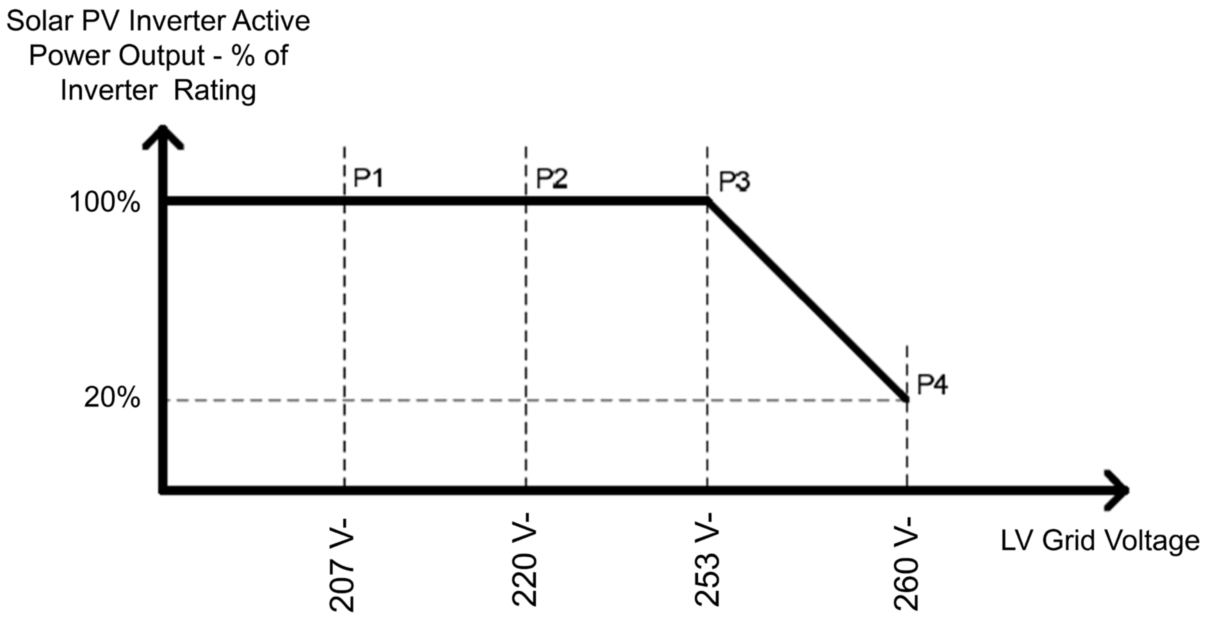


Figure A4.3 shows how conventional LV networks were designed before the use of solar PV. Voltage levels always reduced as the load was carried away from the substation. The normal strategy was to set substation voltage was set just below 253 volts so that despite the fall in voltage along the LV feeder, all LV customers would have an electricity supply that would remain in the allowable 216 to 253 voltage range along the full length of the LV feeder.

The majority of LV networks in the NEM have been designed in this basis.

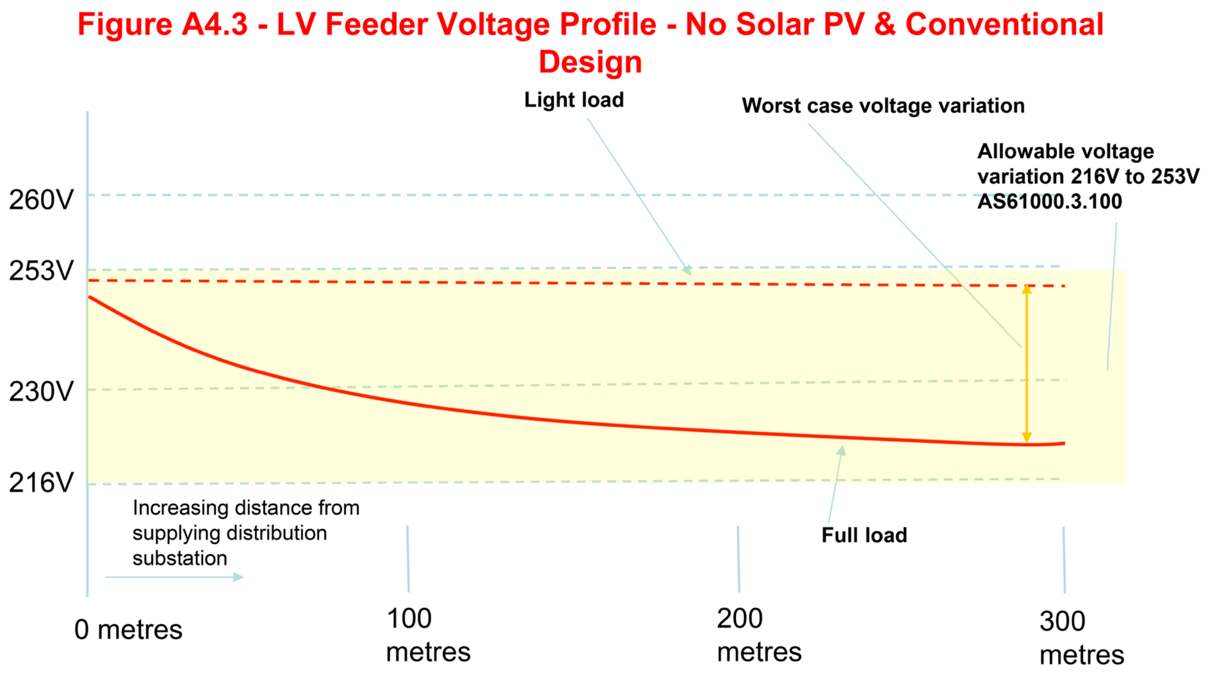
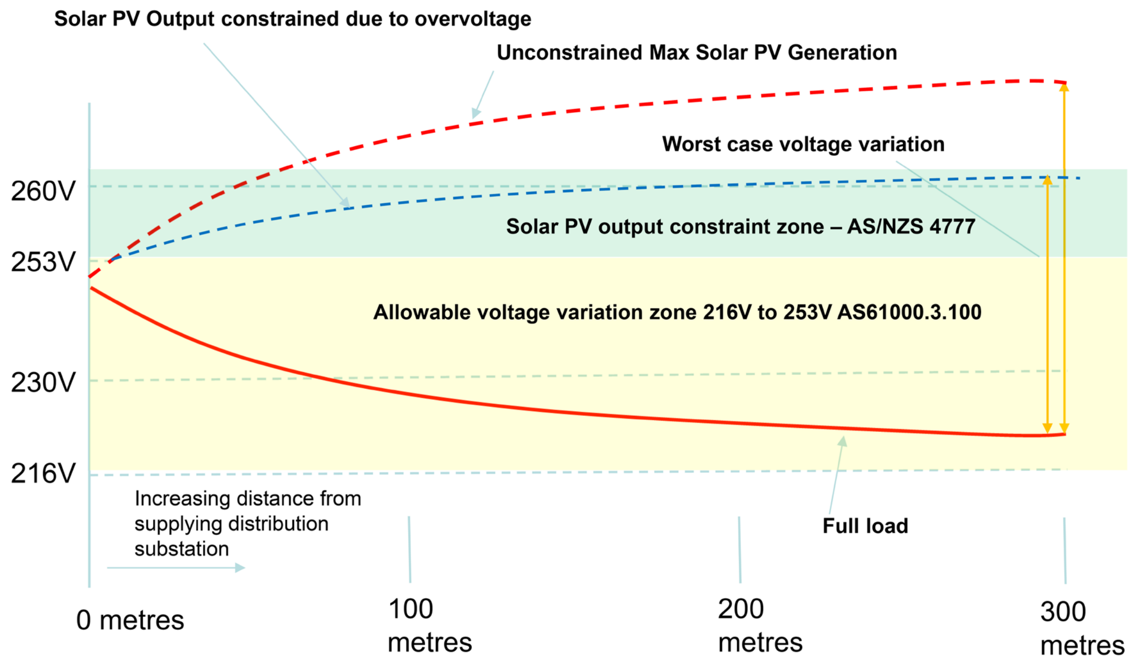


Figure A4.4 shows the impact of installing a high concentrations of roof top solar PV within a conventionally designed LV feeder. The dotted red line shows increasing elevated voltages during maximum solar PV output as distance away from the substation increases. Modern solar PV systems would be forced to curtail their output resulting in voltage levels shown by the dotted green line. Under both these conditions, customer equipment like TV sets, computers, fridges and all other household electrical equipment are at risk of immediate failure or ongoing degradation causing reduced equipment life.

Figure A4.4 - LV Feeder Voltage Profile with Solar PV

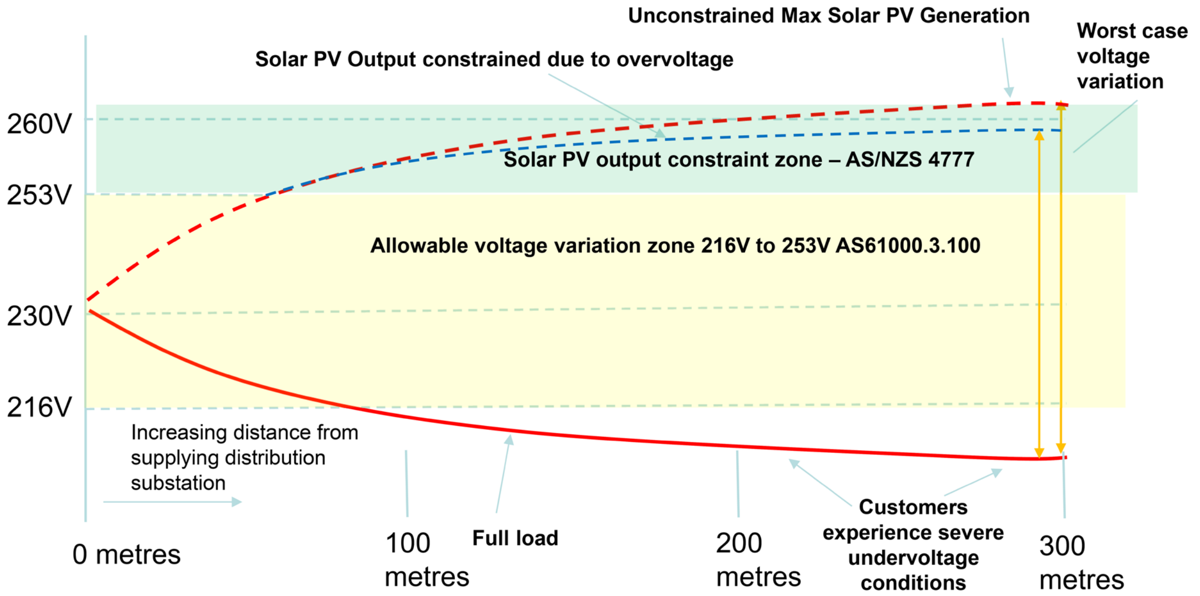


Many distribution companies across Australia are reducing their supply voltages as illustrated in Figure A4.5. The reduced supply voltage has the effect of reducing the overvoltage stress on customer installations but can come at the cost of excessive undervoltage conditions at times of full import load.

When faced with this situation, major high cost investments are needed in the LV network to bring the voltage variations back with the limits of 216 to 253 volts as required by AS61000.3.100. This is essential to protect customer equipment from over and under voltage conditions.

The types of capital investments needed include augmentations of existing LV cables and the construction of new additional substations with associated MV extensions. This work is very capital intensive and benefits only small numbers of customers. When view on a NEM wide basis, EPC analysis shows that the investment costs in this category will greatly exceed the investments in HV Transmission works called up in the Step Change Scenario.

Figure A4.5 -LV Feeder Voltage Profile with Solar PV and Reduced Distribution Supply Voltage



Appendix 3 – Request for Additional Data

In the interests of providing greater credibility to the ISP scenarios and providing enhanced financial reporting it is recommended that the following measures be incorporated into the spreadsheet attachments to the ISP.

Scenario Characteristics

Energy to Customers	2023-24	2024-25	>>>>>	2049-50
Delivered Energy to HV Customers (GWh)	??	??		??
Delivered Energy to LV Customers (GWh)	??	??		??
Delivered Energy to all Customers (GWh)	??	??		??
Renewable Spillage (GWh)	??	??		??
Network Losses (GWh)	??	??		??
Storage Losses (GWh)	??	??		??
Total Losses (GWh)	??	??		??

Customer Demand				
Maximum Demand NEM (MW)	??	??		??
Maximum Demand TAS (MW)	??	??		??
Maximum Demand SA (MW)	??	??		??
Maximum Demand NSW (MW)	??	??		??
Maximum Demand VIC (MW)	??	??		??
Maximum Demand QLD (MW)	??	??		??
Minimum Demand NEM (MW)				
Minimum Demand TAS (MW)	??	??		??
Minimum Demand SA (MW)	??	??		??
Minimum Demand NSW (MW)	??	??		??
Minimum Demand VIC (MW)	??	??		??
Minimum Demand QLD (MW)	??	??		??
Annual Load Factor NEM %	??	??		??
Annual Load Factor TAS %	??	??		??
Annual Load Factor SA %	??	??		??
Annual Load Factor NSW %	??	??		??
Annual Load Factor VIC %	??	??		??
Annual Load Factor QLD %	??	??		??

Continued on next page.

Financial Performance	2023-24	2024-25	>>>>>	2049-50
assets)	??	??		??
$ Weighted Average Asset Life (years - all assets)	??	??		??
Effective Asset Age (years - all assets)	??	??		??
Depreciation Charge $B/year - (2022 dollars)	??	??		??
Depreciated Value of all assets $B (2022 dollars)	??	??		??
System Operation and Maintenance $B/year - (2022 dollars)	??	??		??
Average Cost of Supply to HV Customers $/MWh (2022 dollars - 6% WACC)	??	??		??
Average Cost of Supply to LV Customers $/MWh (2022 dollars - 6% WACC)	??	??		??
Average Cost of Supply to all Customers $/MWh (2022 dollars - 6% WACC)	??	??		??
Capacity Factors				
Black Coal Capacity Factor %	??	??		??
Brown Coal Capacity Factor %	??	??		??
Mid-merit Gas Capacity Factor %	??	??		??
Peaking Gas+Liquids Capacity Factor %	??	??		??
Hydro Capacity Factor %	??	??		??
Offshore Wind Capacity factor %	??	??		??
Wind Capacity factor %	??	??		??
Utility-scale Solar Capacity factor %	??	??		??
Distributed PV Capacity factor %	??	??		??
Storage Performance				
Utility-scale Storage (Discharge Cycles per Year)	??	??		??
Coordinated DER Storage (Discharge Cycles per Year)	??	??		??
Distributed Storage (Discharge Cycles per Year)	??	??		??
Environmental Performance				
Carbon Emissions Intensity t/MWh	??	??		??
Security of Supply				
Minimum Generation Margin Over Demand during year TAS (MW)	??	??		??
Minimum Generation Margin Over Demand during year SA (MW)	??	??		??
Minimum Generation Margin Over Demand during year NSW (MW)	??	??		??
Minimum Generation Margin Over Demand during year VIC (MW)	??	??		??
Minimum Generation Margin Over Demand during year QLD (MW)	??	??		??