SUBMISSION TO AEMO – DRAFT INPUTS, ASSUMPTIONS AND SCENARIOS REPORT 2024.

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General Comment

I wish to initially express concern at the approach taken with this report. It appears to lack structure as a collection of options from which it is difficult to gain an impression of the future optimum energy supply situation. I suggest that the final goal needs to be more clearly defined in terms of the most likely change from the present energy supply mix. There will clearly be different paths to reach that end point as indicated in the report, possibly dictated by circumstances prevailing during the transition period, but that should follow as a separate analysis which could be regularly updated.

I also suggest that the possibility of "Green Energy Export" should be treated separately from the domestic energy conversion as an independent commercial endeavour which should stand entirely on its own merits. If there is a possibility of integration with the domestic energy supply, then that would be a commercial decision at the time and any such change should be commercially viable. The export of green energy may be a general national objective but should not be directed by a national policy.

Comments herein are confined to the assessment of the future energy demand and supply position, and any particular comments essentially relate to Section 3 of the AEMO 2023 Input Assumptions and Scenarios Report.

Assumptions on Energy Use and Conversion.

These are clearly the principal assumption underlying future plans for electricity supply and must include assumptions on the way in which direct present fossil fuel use is changed by electrification and the use of alternative fuels such as biofuels and hydrogen. The starting point should be the total national energy consumption followed by analysis of how that might be changed to eliminate the net emission of carbon dioxide, and lead to an assessment of the amount of electrical energy required. This reconstruction of the total energy supply system does not appear to have been followed in the NEM context which seems to be constructed by adding particular fuel conversions such as cars and some industry applications to the existing electricity demand. The following provides an example of the suggested approach to reconstruction as applied to the total Australian domestic energy supply and demand.

Australia's Present Energy Supply and Demand.

Excluding coal and natural gas production for export, Australia's total primary energy consumption was 5,765 PJ in 2021/22. Final energy consumption was 4,298 PJ with the difference of 1,467 PJ largely representing losses in electrical energy generation.

Consumption for the various sectors of the economy is shown in Table 1, (*Sourced from Dept of Climate Change, Energy, the Environment and Water – Australian Energy Update – Sept 2023).*

Table 1 Australian final energy consumption (PJ per year)

Sector	Coal/other	Gas	Oil	Total fuels	Electricity	Total
Transport	5	2	1396	1403	23	1426
Mining	6	417	283	708	160	868
Manufacturing	202	359	97	658	194	852
Residential	68	164	16	248	249	497
Commercial	1	47	31	79	217	296
Agriculture		1	107	108	6	114
Construction		3	27	30	7	37
Water and waste	1	1	1	3	14	17
Other			85	85		85
Transmission loss					108	108
Total	**283**	**994**	**2043**	**3320**	**978**	**4298**

Energy inputs for electrical energy production are given in Table 2.

Table 2 Energy inputs for electricity production (PJ per year)

Input	Coal/other	Gas	Oil	Total fuels input	Electricity output	Total inputs
Wind					105	105
Solar					125	125
Hydro					61	61
Black coal	1039			1039	364	1039
Brown coal	442			442	117	442
Gas		565		565	177	565
Oil			60	60	17	60
Other fuels	48			48	12	48
Totals	**1529**	**565**	**60**	**2154**	**978**	**2445**

The electrical energy output of 978 PJ is generated from 291 PJ of renewable energy and from 2,154 PJ of fossil fuels. Together with the direct fuel use this gives a total energy input of 5,765 PJ.

Although renewables may presently represent close to 30% of present electrical energy demand, they only represent 5% of total energy use and it is disingenuous to claim that we are well on track to a renewable energy future. It also highlights the magnitude of the task ahead.

Reconstruction and Future Changes to Energy Inputs.

The aim is to eliminate net CO2 emissions by 2050 which will require the phasing out of fossil fuels and replacement with electrical energy or other fuels such as hydrogen or biofuels. Electrical energy use will increase significantly and will need to be produced by renewable methods such as solar PV, wind and hydro, or by nuclear energy.

One example of a fuel conversion scenario might be as follows:

- Coal use and associated mining fuel demand would be phased out and reduce fuel consumption by say 150 PJ.
- Some replacements of hydrocarbon fuels may not be possible, such as for aviation, agriculture, and some remote or portable emergency power generation equipment. This could represent about 320 PJ of present use and in future might be supplied as biofuels.
- Biomethane may replace some natural gas applications with a potential of 370 PJ.
- Some natural gas may still be used if supported by Carbon Capture and Storage (CCS) or other means of carbon offsets. This may be of the order of 400 PJ.
- The remaining 2,080 PJ of present fuel consumption needs to be converted to electrical energy or supplied by hydrogen.
- Hydrogen fuel replacement may be 100 PJ for transport and 400 PJ for industry and mining or 500 PJ in total, representing 4.2 million tonnes of hydrogen. This will require 240 TWh or 864 PJ of electrical energy to produce as compressed gas.
- The 1,580 PJ of fuel converted to electrical energy will be partly used for heat applications and partly for electrification of transport. For direct heat applications there will be efficiency gains requiring around 0.8 PJ of electrical energy for each 1 PJ of fuel energy. For transport applications the conversion may be closer to 0.25 PJ of electrical energy for each 1 PJ of fuel replaced. Taking 2/3 of the demand for transport applications will give an electrical energy demand of 685 PJ.
- In summary the total energy demand in this scenario will be:-

Residual fuels as biofuels	320 PJ
Biomethane supply	370 PJ
Natural gas use with CCS	400 PJ
Electrical energy to supply hydrogen	864 PJ
Electrical energy for direct fuel conversion	685 PJ
Present electrical energy demand	978 PJ
Total energy consumption	**3,617 PJ**
Total electrical energy consumption	**2,527 PJ**

Under this scenario the total energy decreases from 4,298 PJ at present to 3,617 PJ or by 16% due to efficiency improvements from the direct use of electrical energy compared with fuels or heat energy

Electrical energy demand increases from 870 PJ to 2,527 PJ or by a factor of 2.9. Transmission and storage losses must be added to these figures to give the energy generation required. This has been assessed at around 17.5% for a full solar and wind generation system (see separate item below), and will raise the electrical energy generation to close to 2,970 PJ per year from a base of 978 PJ or by a factor of close to 3.

The above example only covers the conversion of the present energy consumption to conditions required in 2050. It does not allow for growth in demand from 2023 to 2050 and does not allow for efficiency improvements in energy use during that time. If it is assumed these two factors were similar, they would cancel, and the projected demand may actually be close to the above situation in 2050.

I suggest that as a first step it would be helpful to clearly identify the final objective for total energy supply for the NEM region with an analysis of this nature.

Hydrogen Production.

One major assumption in the above analysis affecting the increase in electrical energy consumption to 2050 conditions is the use of hydrogen as a replacement fuel and the electrical energy required to generate hydrogen. The above example suggests the possible hydrogen use as a fuel replacement as 4.2 million tonnes per year for the Australia economy as a whole. This may be of the order of 3 million tonnes per year for the NEM region and compares with a figure of 1.3 million tonnes per year given in Section 3.3.6 of the 2023 IAS Report. **This amount of hydrogen would only replace 130 PJ of direct fuel use or 5% of present direct fuel use for the NEM which seems far too low as there will be high industrial demand for the production of ammonia as well as for other heating fuel applications and long-distance transport.**

Electricity Generation.

The present aim is to shift generation to renewables with firming support provided by gas turbines in addition to long term energy storage.

From the *"Australian Energy Statistics – Table O"*, the NEM electricity generation in 2022/23 was 225 TWh which suggests that with conversion along the lines of the above example this could increase to 675 TWh.

The "*2024 Integrated System Plan for the National Energy Market Report*" indicates present annual consumption of close to 200 TWh rising to 500 TWh in 2025 or by a factor of 2.5. Generation required to meet demand is presently 225 TWh which would rise to 565 TWh. This is 16% below the above assessment of a 3 fold increase to 675 TWh which would include increased hydrogen production.

In assessing possible changes in the generation of electricity, hydro capacity is unlikely to increase significantly above present levels at an annual output of 16 TWh due to water supply limitations. This would leave the remainder to be supplied by wind, solar and firming gas or between 549 and 659 TWh indicated for the NEM region in 2050.

The indicated mix of solar and wind is close to 50:50 with solar 50:50 between utility scale and rooftop facilities. Table 3 indicates the generation requirements by type for the two levels of generation, neglecting any contribution from emergency gas generation.

Table 3 Electrical Energy Generation.

	Present	Future as per ISP Report		With extra H2 production	
	Capacity	Generation TWh	Capacity GW	Generation TWh	Capacity GW
Total generation	200 TWh	565		675	
Hydro		16		16	
Wind	10.6 GW	275	86	330	103
Utility scale solar	8.6 GW	137	75	165	91
Roof top solar	18 GW	137	97	164	116

Table 3 indicates that the increase in renewable generating capacity from the present level will be 8 to 10 times for wind, 9 to 11 times for utility scale solar and 5 to 6 times for roof top solar. The 2023 IAS Report only indicates an increase in rooftop solar from 20 to 80 GW to 2050 or by a factor of 4. Other data is not apparent.

There is also no indication in present reporting of what allowances have been made for increased transmission and storage losses with a fully renewable and geographically extended system.

Energy Storage.

Short term energy storage in the form of batteries is required for instant response to renewable variations and to cover lack of supply during nighttime hours. It also serves to stabilise frequency and voltage control of the power system and can provide around 4 hours of peak demand. Long term storage such as pumped hydro is required to ensure supply over extended periods of low output and to cover seasonal variations in supply. Emergency gas turbine power generation is an alternative to long term storage which can be excessive, and a combination of the two will give an optimum position. **Various scenarios of excessive renewable capacity, emergency generation, and energy storage requirements need to be examined to define the optimum situation and this is by no means apparent**.

As an example, it is estimated that with 20% excess wind and solar capacity to meet supply and 5% supplementary power generation, the long-term storage required will be around 15 hours of average demand. This level of long term storage will vary depending on location and prevailing weather conditions and is taken as a likely level for a largely interconnected power system.

On this basis and for batteries at 4 hours of average renewable supply, the capacity required would be 260 GWh. For longer term, with pumped hydro storage at 15 hours of renewable supply, the capacity will be close to 1,000 GWh.

The present 2023 IAS report indicates possible battery ratings of 40 GW and a VPP contribution of 30 GW, indicating a total of 70 GW, although there is no indication of the actual energy storage capacity. If this averages 4 hours, then storage capacity will be 280 GWh much in line with the above assessment**. It is important that the actual storage capacity in GWh is defined not just the power capacity as it will determine the amount of emergency gas generation needed.**

Pumped hydro storage limits are given in Section 3.5.4 Table 30 of the 2023 IAS Report and indicate a total of 446 GWh which is well short of the above indication. Tasmania alone is 59 GWh and Snowy Hydro 2 is 350 GWh so this limit given in Table 30 is questioned.

There is no indication of accounting for the energy losses associated with storage. Even though the actual storage levels may be low, if frequently used such as with solar during nighttime hours or for wind during normal operation, the amount of energy passing through the storage system can be high and suffers a loss of at least 10 to 15%.

Energy Losses.

It is important to consider both the energy losses associated with transmission for an extensive renewable energy system and the energy losses associated with storage which combine to increase the amount of energy generated to meet a given energy demand.

The indicated electrical energy transmission losses in the present national system as given in Table 1 is close to 10%. This is highly likely to be greater for a widely distributed renewable energy system at say 12.5% or more. In addition, the losses incurred in energy storage are likely to be of the order of 15% of the energy input and with renewables it is likely that at least 35% of the energy generated will need to pass through storage giving a net loss of at least 5% of total energy generated. This will give a total energy loss from renewables of around 17.5% due to these two factors which would be more than double the losses from large scale base load supply at around 7%. It is certainly unclear whether these factors have been considered in developing the energy generation capacity required for 2050.

Emergency Gas Generation.

Separate assessments have indicated that with the levels of storage suggested this will need to be around 5% of electrical energy consumption from wind and solar sources or 28 TWh per year.

Section 3.5.1 of the 2023 IAS Report indicates installed gas capacity of around 10GW, but there is no indication of the amount of energy likely to be generated. The 2024 ISP Report, Figure 9 suggests that this may be of the order of 6 TWh. In that case the facility would operate at maximum output for 600 hours per year or 6.8% of the time, but this represents only 1.2% of the wind and solar output. In view of the relatively lower level of long term storage capacity provided this does not appear to be adequate.

Detailed modelling of the total energy supply system is required to assess the amount of short term and long term storage needed, the excess capacity of wind and solar capacity, and the amount of emergency gas generation required. There is an interplay between all these parameters which does not appear to be adequate for the projected system predominantly based on wind and solar generation.

Transition Variations.

Given the optimum final position there will be different scenarios for reaching that goal over the next 25 years, such as discussed in the IAS Report. It is suggested that this aspect needs to be separately reported based on the various paths to the final goal and would need to be continuously updated.

Carbon Sequestration.

It is noted that this plays a significant role, with the stated current storage level given at 20 million tonnes pa of CO_2 and rising to 160 mtpa in 2050.

This concept is highly questionable, firstly due to the high cost of addition to gas turbine power generation at 4 to 5 times the capital, higher annual costs and the need to generate extra power to operate the CCS system. Alternatively, it may preferably be used for direct fuel applications or in the generation of hydrogen from natural gas. However, CCS has only been partially successful for the return of CO_2 to depleted natural gas reservoirs rather than injection into fractured rock structures. This will limit the scope of CCS in the future and although it may be a partial short term measure, **it is suggested that the extent of CCS use long term given in the IAS Report is highly questionable.**

Direct Air Capture of CO_2 (DAC) is also mentioned as a possibility by 2040. This presumably also requires CSS in addition to be of any value or else to use the recovered CO_2 with hydrogen to produce synthetic fuels. The energy demand and cost of DAC is extraordinarily high as a means of producing synthetic fuels and there are other far more economic approaches for the production of biofuels. Also to have any impact on the level of CO_2 in the atmosphere, the use of DAC is quite a futile exercise given the amount of energy required and any consideration of this should realistically be abandoned.

Nuclear Energy.

Section 3.1.4 of the 2023 IAS Report dismisses the nuclear option because the ability to install nuclear power is currently not legislated. This belies the fact that it can provide reliable zero emission electrical energy over a long period of time and at comparable cost to renewables with storage and other firming facilities in the immediate term, and at much lower cost in the longer term when renewable capacity has to be replaced. Where it has been operating around the world for many years nuclear power now represents by far the lowest cost the electrical energy available.

Electricity demand profiles suggest that a base load of the order of 30% of total energy supply could be provided by nuclear, with operation at full output and at maximum efficiency. For a total of between 565 and 675 TWh this would represent a nuclear output of 170 to 200 TWh and a plant capacity of 21 to 26 GW. This would replace and reduce installed renewable capacity by between 77 and 93 GW or 3.7 times the added nuclear capacity.

The inclusion of reliable base load supply will reduce the energy storage needed to a significantly greater extent than the reduction in associated renewable generating capacity and will also similarly reduce the emergency gas generation required. As noted above it will also significantly reduce energy losses. These are important cost credits attributed to the inclusion of nuclear into the energy generation mix and need to be quantified by total system modelling. The cost contributions of renewables and nuclear cannot simply be made by comparing the "levelized cost of electricity".

The argument is advanced that it will take a decade before nuclear can be introduced. However, that is no reason for it to be abandoned as part of the ultimate solution. Much of the renewable energy generation up to 2030 will all have to be replaced before 2050 and nuclear can be incorporated into the transition plans to fill such replacements as well as supplying part of the ongoing generation expansion over the next 25 years.

Legislation can be changed with good reason and the responsible approach must be to properly assess nuclear as part of the final energy supply solution. Whether or not it meets particular economic criterion may be a deciding issue, but costs will change with time and need to be regularly appraised.