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RE Draft 2023 Inputs, Assumptions and Scenarios Report (IASR) – Comments from Simon Bartlett

As background, I am a past professor in electrical engineering at the University of Queensland where I held the Australian Chair of Electricity Transmission for 7 years. I also worked in the power industry for 40 years, including 17 years as Powerlink's COO, 7 years as QEC's chief engineer generation and transmission and 16 years as a planning engineer for SECQ and Ontario Hydro. I planned many major generation and transmission projects, most of the existing electricity infrastructure in Queensland. In In planning these investments, I developed and ran computer simulation programs being the forerunners to those used in the ISP. My contributions to Australia's electricity supply industry, were recognised in 2012 by the award of Member of the Order of Australia (AM).

I wish to thank AEMO for this opportunity to contribute to the data and assumptions that will underpin the 2024 ISP, and hope my comments are taken in the spirit they are given to help identify the future path for Australia to reduce its power system CO2 emissions at the lowest cost to the nation while ensuring the reliability of essential electricity supply.

Comparison of recent actual performance against projections for data and assumptions

As a general comment, the data and assumptions appear to be based on a range of technical, economic and political projections of the future, however there appears to be little calibration of these forecasts against what has factually occurred recently in measurable outcomes. An example is basing the projections of the future CO2 emission caps on aggressive political targets when Australia's actual total emissions increased by1.5% in the year ended March 2022 as published in the Quarterly Update of Australia's National Greenhouse Gas Inventory. It is suggested that a sensitivity study could include varying the CO2 caps as they appear to have a huge impact on the modelled future development paths.

Scenarios

The driver of the different proposed scenarios appears to be the rate of change in government policies rather that the rate of change in the external economic environment noting that the examples of scenarios in the AER Guidelines for Cost-Benefit Assessments including the ISP are based on the latter. The external economic environment could determine Australia's electricity requirements and the costs and availability of skilled workers to build the transmission, generation and storage projects that are used in the ISP to estimate the costs and benefits of each development path for each scenario. Basing the scenarios on the rate of change of government policies rather than changes in the external environment may result in the scenarios reflecting political agendas that may not be practically achievable, as well as failing to include the key global and national economic drivers that will determine the future environment for Australia's electricity development as well as the viability of development options. As an example, by dropping the slow change scenario there may not be a scenario reflecting the likely economic environment should the predictions of a global recession, continuing war in Ukraine, even higher inflation rates and interest rates, increased COVID disruption of supply chains and shortages of skilled labour. It is suggested that consideration be given to another Step Change scenario which aligns with a change in the external economic environment along lines such as this.

Shortages of rare metals

None of the scenarios include the forecast shortage of the rare metals required for the technologies to be widely implemented in the energy transition such as batteries, PV cells, windfarms, electronic components, etc. Nor do they consider China's global monopolisation of the mineral deposits required to produce these essential materials or being the predominant global supplier of much of the required plant and equipment. As this could become a roadblock in Australia's optimal pathway to net zero emission, it may need to be considered, possibly as one of the scenarios, in the ISP.

Objective function used in Linear Program to develop optimal development plans

The objective function used for AEMO's linear program to determine the NPV of net benefits (costs less benefits) appears to have an incorrect objective function that only includes annualised costs over the modelling period ending 2050/51, whereas to be economically correct and to comply with the AER Cost Benefit Guidelines, NEC and RIT-T, it should calculate the NPV of capital investments, annual operating costs and include an appropriate terminal values at the end of the modelling period for all transmission, generation and storage investments. It is apparent that the current objective function is skewing the transmission/generation/storage development plans towards low capital cost/high operating cost options. This may be the cause of the development plan for the ODP counterfactual retiring more than 7,000MW of newly built pumped storage schemes (costing more than $14bn), only 4 to 20 years after commissioning, and to replace them with OCGT's running some 1,200 hours a year on costly gas and generating CO2 emissions equivalent to putting 1.5million cars back on the road. The current objective function may have been responsible for the ISP 2022 concluding that the ODP would deliver a $14.4bn net benefit to customer, whereas the implausible early retirement of $14bn of PHES alone appears to have contributed around $3.4bn to that figure. It is suggested that the objective function's compliance with the regulations be reviewed and redesigned if necessary.

Operation and maintenance costs for transmission developments

The assumption that transmission developments are only 1% pa of their capital investment cost would appear to be inconsistent with the AER's Annual Benchmarking Report for Transmission Network Service Providers – November 2022. Table B.2 of that report lists the OPEX, CAPEX and depreciation for the eastern state TNSP's Powerlink, TransGrid, AusNet Services and TasNetworks. Noting that most of the CAPEX spent by these TNSP's in the last five years has been to refurbish and replace their ageing transmission assets, both the OPEX and CAPEX should be considered in estimating their total ongoing annual expenditure on their transmission assets over their full life-cycle. The depreciation can be multiplied by 40 years (being the estimated average economic life for their transmission lines (50 years), substations (40years) and electronic substation equipment (15 years)) to estimate the undepreciated total cost of their transmission assets. As illustrated below, the AER benchmarking data in Table B.2 can be used to demonstrate that the actual life-cycle annual cost of transmission investments averages approximately 3.3% pa with little variation between the eastern state TNSP's:

	Total Assets Cost $m	Opex %pa	Capex %pa	Overall %pa
ElectraNet	$4,760m	2.1%	3.0%	5.1%
Powerlink	$12,000m	1.8%	1.2%	3.0%
AusNet Services	$7,360m	1.2%	2.1%	3.3%
TasNetworks	$2,520m	1.2%	1.9%	3.1%
TransGrid	$11,400m	1.5%	2.0%	3.5%

It is also noted that the assumed O&M costs in AEMO's WRL PACR was 3.5% pa for the preferred option which is included in the ISP as an anticipated project. The assumption that the annual costs of all future transmission would be as low as 1% pa would appear to be unrealistic compared with the above analysis based on the most recent AER Benchmarking. This is an important assumption as a 3.3% pa annual expenditure over the 50 year life of a transmission asset would total 165% of the capital investment and have an NPV exceeding 50% of the NPV of the investment. Assuming only 1% pa would be equivalent to only 16% of the NPV of the investment. The additional 34% (50% - 16%) would meant that the net benefit of the actionable projects in the ISP 2022 may have been $5bn lower than the $14.4bn had 3.3% pa been assumed instead of 1% pa. It is suggested that the AER's latest benchmarking of TNSP's costs, both opex and capex expressed as a percentage of their undepreciated total asset base, be considered in arriving at a realistic assumption for the total ongoing annual costs of transmission investments over their full life cycle.

Cost of transmission connections to modelled generation and storage

The data and assumptions include in the estimated generation capital cost estimates include an allowance for the capital cost of the transmission connection for each MW of modelled generation or utility scale battery storage of around $110/kW for most locations in the NEM, but with higher connection costs in Victoria. There are no specific connection costs for PHES as it is assumed that an allowance has already been included in the PHES generation costs. When the ISP lists the cost of its proposed transmission investments, the total cost of transmission connections to the modelled generation and storage is not included yet appears to exceed $20bn for the Step Change scenario. The assumed $110/kw would appear to be too low based on the following publicly available generation connection costs:

(a) The $170m 330kv connection to the Macintyre and Karara windfarms with a combined capacity of 1,026MW would average $166/kw
(b) The $295m 275kv connection to the 450MW Kidston pumped storage scheme would average $650/kw.

It is suggested that the assumed cost of transmission connections in the IASR be reviewed in the light of publicly available information on actual connection projects and that the ISP 2024 include the total transmission connection investment for all committed, anticipated and modelled generation and storage investments for each scenario so that there is a complete picture of the NEM's needs for new transmission infrastructure driving the need for skilled workers and materials.

Assumed discount rate of 7% pa

The proposed discount rate of 7% pa appears to be low given that the NER requires it to reflect the return that private investors would require before investing in transmission, generation or storage infrastructure. This should be consistent with their required return on equity , current costs of debt and an appropriate risk margin and taxes. Considering the slow-down in investment due to the shortage of funds, spiralling interest rates, combined with an outlook for global recession and an escalation of the Ukraine war, it may be appropriate to assume a higher discount rate. Whilst the ISP will test the sensitivity of variations to the discount rate, it is important that the central rate is realistic. It is recommended that additional expert advice be sought on the appropriate rate of return now required by private investors given current market conditions. It may be appropriate to use a lower discount rate for calculating the NPV of transmission investments due to their lower risk profile and their easy access to low interest rate federal government funds though the $20bn Rewiring the Nation initiative.

Network Transmission Limits, System Strength and Network Stability

The recent decision by Snowy Hydro for all six Snowy 2.0 units to have variable speed motor/generators may not be reflected in the transmission limits assumed for transmission cut-sets in south-eastern Australia, including those related to PEC, VNI West, Humelink and the Sydney Ring. The adoption of power electronic devices to connect the Snowy 2.0 units to the power system is equivalent to the inverter-based technology used to connect utility scale solar and wind-powered generation. This technology virtually eliminates the synchronous torque from the generating source and its effective inertia which could lead to substantial reductions in power system stability limits in that part of the transmission network. It also produces very high frequency harmonics that can interact with other inverters to cause undamped voltage oscillations as has occurred in South Australia , Western Victoria and South-West NSW forcing AEMO to constrain off-line the relevant generators. There have also been failures of new transformers near the harmonics source in South Australia and overseas due to the high frequency harmonics overheating the transformer insulation as they were not designed for those harmonics. These risks extend to the insulation of reactors and cables. It is suggested that this development and its likely effects on the transmission limits in south-east of the NEM applicable to PEC, Humelink, VNI West and the Sydney Ring be investigated, and if necessary that the transmission limits be reduced.

Assumed round-trip efficiency of Snowy 2.0

The IASR assumptions include an assumed round-trip efficiency for Snowy 2.0 of 74% compared with a round-trip efficiency of 70% assumed for the Wivenhoe PHES. It is understood that the 74% assumed for Snowy 2.0 is a theoretical calculation from the Snowy 2.0 feasibility study report whilst the 70% for Wivenhoe may be based on its actual performance. However , as explained in the Snowy 2.0 feasibility report, its round trip efficiency can deteriorate quite significantly if Snowy 2.0 is operated at higher levels of generation and pumping than assumed for the 74% calculation as well as when the surface of the concrete lined tunnel becomes pitted by operation at full generation or full pumping for excessive durations. It may be necessary to consider the forecast operating levels of Snowy 2.0 that are predicted in the ISP, which expect Snowy 2.0 to operate with an annual capacity factor exceeding 25% thoughout the modelling period. Based on a 74% cycle efficiency, this would be equivalent to operating at 2000MW generation for 2,200 hours a year and 2000MW pumping for another 3,000 hours a year, representing 59% of the year. The 74% efficiency calculation was based on Snowy 2.0 operating at only 1,000MW and only operating at full load for 1% of the year. Considering that water pressure losses in the 27,000m long tunnels theoretically increase with the cube of the water flow, there would be a substantial reduction in efficiency when operating at full generation and pumping for most of the year. The feasibility study predicted that the cycle efficiency could reduce to 65% if Snowy 2.0 operated at its full 2,000MW output. It also explained that the concrete lined tunnels with a 10m diameter had been selected as the station would rarely operate at its full 2,000MW, and that high water velocities create turbulence at the concrete surface which can erode the surface creating pits that further increase the water pressure losses and reduce the efficiency. Whilst the pitting could be repaired by painting the concrete surface, this would require the whole power station to be off line for a very long period to resurface 27,000 metres of 10m diameter tunnels and cost a very large amount. It is suggested that Snowy Hydro be consulted on the relationship between the extended operation of Snowy 2.0 at maximum generation and pumping and its round-trip efficiency and ongoing refurbishment costs.

Assumed Transmission investment costs based on the Transmission Cost Database (TCD)

The IASR assumptions for the required investment for modelled transmission projects are proposed to be estimated from the TCD. Whereas the cost estimates for committed and anticipated projects are normally based on advice from their proponents. It appears from a comparison of the average costs of these two sources using their average cost/km, that the estimates from the proponents can typically be some 40% greater than the TCD cost estimates. An example being the $5.9m/km for extending VNI West to Sydenham in table 10 of the updated WRL cost benefit assessment compared with the $8.2m/km for VNI West in its PADR being 39% higher. An examination of Table 3 in the updated WRL assessment indicates that the TCD cost estimate should be increased by approximately 40% to allow for adjustments, known risks and unknown risks to arrive at a realistic cost estimate. It may also be necessary to include an appropriate allowance for the associated cost of the required easements and land purchases including expenditure to build social licence. It is suggested that the TCD cost estimates be increased by 40% to include the above risks and that appropriate costs to secure the necessary easements and land also be included, to ensure consistency with the cost estimates from proponents on committed and anticipated projects.

Assumed commissioning date for Snowy 2.0

The assumed date for full operation of Snowy 2.0 may need to be reviewed and updated, by undertaking a due-diligence of the publicly available information, including the estimate's committee debate on 8th February 2023 which is available online. The Snowy Hydro CEO/COO advised that the tunnel boring machine named Florence that is boring the 16,000m headrace tunnel has only progressed some 200m in the last year as it was "stalled/bogged" at the start and since December has again been "stalled" as the 60m of ground cover above the TBM collapsed onto it leaving a 60m deep hole to the surface through which daylight can be seen. The CEO advised that the critical path for the entire project has flipped from the excavation and fit-out of the underground power station to the tunnelling. This is unsurprising as it would take 70 years for Florence to complete her task at the rate achieved over the last year. The COO was unable to advise when the Snowy 2.0 project is expected to be completed until the power station cavern excavation is halfway. This may be because of uncertainty with the suitability of the geology to support such a large underground cavern. It is suggested that the available information on construction progress of Snowy 2.0 be monitored using an independent expert in the construction of underground PHES to provide a reliable alternative view on the likely completion date for Snowy 2.0.

Please note that nothing in this submission is confidential and is based on publicly available information.

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