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Energy Networks Australia response to the *Draft 2021 Inputs, Assumptions and Scenarios Report*

Energy Networks Australia welcomes the opportunity to provide input during the consultation period on AEMO's *Draft 2021 Inputs, Assumptions and Scenarios Report* that will inform the ISP2022.

Energy Networks Australia is the national industry body representing Australia's electricity transmission and distribution and gas distribution networks. Our members provide more than 16 million electricity and gas connections to almost every home and business across Australia.

We welcome the inclusion of hydrogen in the ISP2022 and while to date the focus of decarbonisation has been on the electricity sector, gas networks are on their own decarbonisation journey. Customers tell us that they are seeking a clean energy future and are exploring the role of hydrogen in offering emission reductions from gas use.

Our comments focus on the:

- growing prevalence of distribution-connected DER;
- need for collaborative engagement with networks;
- need for clarity in transmission planning
- "Export Superpower" scenario; and
- related hydrogen modelling.

You will also find a series of responses to specific questions in the Appendix.

Future role of distribution networks

Distribution has a critical part to play in future ISPs

ENA agrees with the paper that distribution networks represent a missing piece of the forecasting puzzle and given the rising penetration of DER devices connecting to the larger system via the distribution network this makes sense. It also highlights the need for AEMO and networks (both distribution and transmission) to identify unique, local scenarios that each NSP is best placed to provide to AEMO.

How this input is then used by AEMO in the larger forecasting exercise is still to be determined, but we and our members welcome future discussion and engagement with AEMO on this issue.

Diminishing returns in forecasting

Like any other resource intensive exercise, there may be a point at which continuing to seek more and more detailed data from the distribution networks for forecasting might begin to have diminishing returns. For example, it does not make sense to conduct complex power flow system modelling for every house and street for the purposes of aggregated, national system planning.

We believe that considering their local knowledge and expertise, DNSPs are best placed to partner with AEMO to meet such objectives.

We encourage collaborative engagement with networks

In recent discussions between DNSPs and AEMO the need for a consistent and thoughtful process by which to request and exchange information for specific purposes was identified as a critical issue. As mentioned earlier, the impact of DER at the distribution level will continue to have ramifications for the larger system that must be considered.

The "how, what, where, when and who" of this data is still to be determined, but to ensure efficient outcomes some core principles should include:

1. A shared understanding and agreement of the data required
2. Data that is provided should have a specific purpose, not supplied for its own sake
3. Ad hoc requests should be heavily scrutinised for purpose, costs, and benefits

The DER register, combined with weather forecasting (and climate projections), will give insights into energy use on operational and planning timeframes. The current AEMC review of the regulatory framework for metering services may provide additional avenues for data access.

Clarifications for transmission

Appropriate discount rates

In the 2020 ISP AEMO used the discount rate calculated in late 2018 for the ENA RIT-T Handbook published in March 2019. ENA has since updated this RIT-T Handbook to only cover non-ISP RIT-Ts. The AER's CBA Guidelines published in August 2020 are the key document to guide the discount rate.

AEMO have used the ENA methodology and updated the risk-free rate, forecasting inflation and cost of debt using the AER's most recent parameters in Dec 2020. AEMO propose using 4.8% real, pre-tax discount rate for most scenarios and a lower value of 3.8% for the slow growth scenarios.

Using the ENA methodology these numbers appear reasonable. However, AEMO needs to satisfy itself that this meets the requirements on AEMO in the CBA Guideline.

Consistent use of Value of Customer Reliability numbers

AEMO is required to use the most recent Value of Customer Reliability (VCRs) published by the AER at the time AEMO publishes the ISP timetable. They are also required to use the most relevant VCRs for the load associated with an unplanned outage.

ENA notes that AEMO propose instead to use the residential VCRs by state which were available at the time of the ISP timetable publication. In contrast for non-ISP projects the RIT-T Handbook recommends using the most recent AER VCRs updated by the CPI-X approach and the AER VCR estimates would be weighted according to the make up of the specific gross load customers impacted by the options in the RIT-T.

ENA recommend that AEMO consider using volume weighted VCRs, including agriculture, commercial, industrial and large business where relevant.

Transparency of early stage works

AEMO held a public transmission cost database webinar in January. This AEMO project to establish a database to collate costs throughout the project is progressing and will be the subject of a consultation phase in May 2021. The database will include costs as the projects progress through the regulatory stages, final project budgets or Contingent Project Application (CPA) costs and the actual expenditure.

Attendees at the webinar suggested that the database should be made public for all ISP projects. The total project cost values could be provided in a de-identified manner for information that is not public in policy statements or CPAs. This would allow consumers, who ultimately fund ISP investments, to have clear oversight of costs.

ENA support the suggestion that the database be transparent and should include past ISP projects with the information available and include all states (including Victoria) not just all future ISP and REZ projects to the extent that this can be accommodated in the Victorian contestable framework.

Policy assumptions

The final ISP will be produced by 30 June 2022, there may be benefit in considering committed policy updates up to a date closer to the final ISP to ensure that the final ISP reflects the latest information. ENA support AEMO's approach to incorporate the Victorian policy, for example, if it is available prior to the ISP modelling commencing.

ENA recognises the ISP workload is significant, but it is important that consumers and other industry stakeholders have confidence in the final ISP and the optimal development path.

It would be ideal if state and federal government policy could be better coordinated to meet the timeframes for AEMO's development of the ISP. For example, the NSW Electricity Infrastructure Investment Act requires the consumer trustee to develop a 20 year plan every 2 years under the Act. There would be benefit if the updated plan, agreed through the NSW governance processes, was timed to feed into future draft IASR's.

AEMO also propose to apply a lower WACC to generation projects within declared REZs, specified as 2% lower than that applied to other generation and transmission investments. AEMO states that this approach is guided by the NSW Government's NAB WACC report.

This seems at odds with the general principle that both generation and transmission investment should have the same discount rate.

Interaction between electricity and gas

The holistic nature of how electricity and gas are assessed is greatly impacted by externalities such as volatile international pricing. It is important that stakeholders engage on gas pricing during the IASR phase and have confidence in the final prices used in the ISP.

ENA supports sourcing the longer-term gas prices from an independent expert with alternate views being similarly evidence based.

Modelling renewable energy without Renewable Energy Zones

AEMC is currently considering improvements to the Dedicated Connection Assets (DCA) model and has proposed splitting the transmission role for a radial DCA between a transmission owner and a transmission operator. Essentially this creates parts of the transmission system underpinned by commercial agreements and may or may not be consistent with the nationally developed optimal development path.

State-based Renewable Energy Zone (REZ) policies could also fall into a similar category where REZ timing and sizing is led by states and is not based on the ISP optimal development path for the NEM. Where other parties may be driving REZs and the build of transmission outside of the ISP, there may be benefit in clarifying exactly what is assumed in the base case.

"Export Superpower" scenario

Electrification definition

The use of the term "electrification" in the consultation paper can be misleading as it is often interpreted as replacing the end use of gas with electricity. While the scenario does replace natural gas with electricity generation to produce hydrogen, the use of hydrogen results in gas infrastructure continuing to be utilised.

ENA recommends that this term is clarified and that the assumptions regarding electrification are clearly articulated.

Energy efficiency

The IASR assumes that the NCC Futures will be adopted in the Export Superpower scenario. The NCC2022 under preparation is technology neutral and the new codes being developed for residential buildings should support both energy efficient gas and/or electrical appliances. The IASR should similarly adopt an energy neutral approach.

Energy Networks Australia is keen to participate in the FRG workshops on energy efficiency levels to be adopted in the ISP 2022.

Level of climate ambition

The "Export Superpower" scenario combines a range of very ambitious goals into a single scenario. It brings forward the date of carbon neutrality in Australia to 2040 (while the Central scenario does not achieve this until after 2050). At the same time it introduces a new hydrogen export industry that will require more than 4 times the current electrical energy provided by the NEM.

The "Export Superpower" scenario goes from a NEM in 2025 that supports a small amount of hydrogen production, to an electricity system in 2050 that predominantly focusses on hydrogen production with a side stream for traditional electricity usage to supply the NEM. This is five times larger than the current electricity provided on the NEM (Figure 5 of IASR).

ENA supports this level of ambition with regard to hydrogen, but this scenario is significantly different from the other scenarios. Perhaps a more appropriate approach would be to either reduce the level of climate ambition to the same (RCP2.6) as the "Sustainable Growth" scenario or, alternatively, increase the level of climate ambition of the "Sustainable Growth" scenario to align with RCP1.9. This would more clearly focus the "Export Superpower" scenario to reflect the opportunities presented by hydrogen.

Furthermore, the climate ambition of the "Central" scenario should more closely align with stated policies in Australia. While the Commonwealth Government has ratified the 2015 Paris Agreement, all States and Territories have a climate ambition of reaching net-zero by 2050 or earlier. ENA recommends that it would be more appropriate for a Central scenario to reflect this net-zero by 2050 ambition.

Domestic emission targets and reductions

The IASR report states that no negative emission technologies are modelled for the electricity sector and that the Land Use Land Use Change and Forestry (LULUCF) sector will balance any leftover emission from energy by acting a s a carbon sink. This is a major assumption that could result in misleading results.

Future Fuels CRC is currently completing range of emissions scenarios to assess the role of hydrogen to reach net zero emissions by 2050. Through this work, it has been noted that there are a range of sectors that will need carbon offsets to reduce their emissions as no net-zero emission technologies are commercially available. For example, offsetting aviation fuels, process emissions from cement production or emissions from the use of refrigerants in the economy. The LULUCF sector has offsetting limitations, so it is perhaps unreasonable to apply it for balance emissions left over in other sectors.

Hydrogen modelling

We would like to encourage AEMO to review the Gas Vision 2050[1] to support insights into the future role of hydrogen, some of which are detailed below.

Hydrogen demand

Hydrogen is only considered in the "Export Superpower" scenario which reaches net-zero emissions by 2040. Yet the domestic switching from natural gas to hydrogen is noted as being completed in 2045 – a full five years after reaching net-zero in this scenario. It should be clarified whether the net-zero target by 2040 is reached through offsets of natural gas, and if natural gas can be fully offset with LULUCF, what the drivers are for then fuel switching to hydrogen.

REZ developments should only be directed by the "Export Superpower" scenario where domestic customers are the direct and primary beneficiary of the investment. ISP investments Hydrogen for export industries should not be subsidised by Australian customers.

The IASR does not appear to dedicate any hydrogen for power generation so the natural gas displacement only includes the industrial and residential/ commercial sectors. Clarification on the role of gas and the potential for hydrogen to be used for electricity generation (or electricity storage) is required.

The domestic demand of hydrogen used appears inconsistent with gas demand projections. There appears to be a shortfall of (~160 PJ) between the hydrogen that displaces natural gas in the "Export Superpower" scenario and the amount of energy required to support the industrial and residential/ commercial sectors (e.g., 2020 GSOO). ENA seeks clarification on whether this is due to electrification of residential and commercial services.

[1] https://www.energynetworks.com.au/projects/gas-vision-2050/

Location of electrolysers

The IASR presents five different hydrogen export pathways (figure 51) and provides additional information on two of these.

The IASR assumes that electrolysers are located near the export facilities and that hydrogen is produced there. This implies that the electricity is delivered from the REZ to the electrolyser precincts via electricity transmission lines.

An alternative might be to assume that hydrogen production occurs in REZ and is then delivered to the port via high pressure pipelines.

Hydrogen storage

The IASR assumes that there will be limited hydrogen storage. This is inconsistent with the potential storage available in current gas infrastructure. Existing gas storage sites have a capacity to store around 27,000 GWh of natural gas (or 97 PJ), representing around 2 or 3 months of domestic gas consumption on the east coast, excluding export storage facilities.

Conclusion

The ISP provides investment guidance for electricity transmission infrastructure, and as such the inputs and assumptions used should produce plausible scenarios.

The role of distribution networks is a missing piece and ensuring the appropriate level of integration between the modelling of transmission and distribution networks would need to be considered further to ensure national planning objectives. We encourage AEMO to continue to work with DNSPs to understand how current distribution planning approaches can most usefully provide inputs into the ISP process.

It is apparent that there are also a number of clarifications required for the electricity transmission aspects of the ISP including but not limited to policy and economic assumptions.

The current format of the “Export Superpower” scenario, appears to assume a greater level of electrification of domestic natural gas consumption compared to the other scenarios. A more plausible approach may be to create a scenario with hydrogen replacing some domestic use of gas to reflect current strategy of the gas networks.

If you have any questions or would like to discuss specific topics further, please do not hesitate to contact me (jcainey@energynetworks.com.au).

Yours sincerely,

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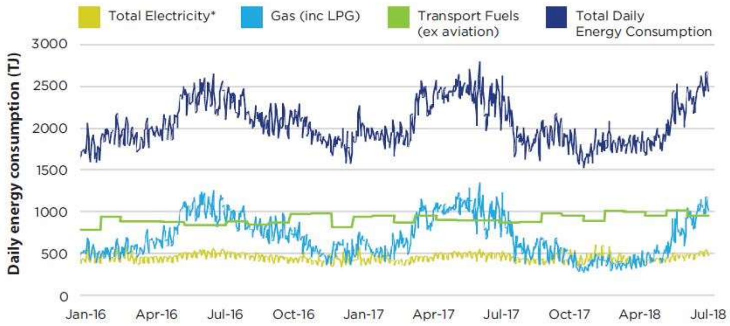
Appendix: Responses to consultation questions

MATTER FOR CONSULTATION	Energy Networks Australia response
2.3.5 EXPORT SUPERPOWER	
What, if any, elements of the Export Superpower scenario as proposed are not plausible or internally consistent, and how would you suggest they be altered?	This scenario represents a major change from the Central scenario compared to the other scenarios. It contains an increased level of climate ambition, an increased level of electrification of gas services and an additional hydrogen export industry, which would require 4 to 5 times the current electricity supplied by the NEM. It may be more appropriate that a domestic hydrogen use scenario be considered separately.This scenario would cover the replacement of domestic consumption of natural gas with hydrogen based on the same climate ambitions as the Central scenario and exclude exports.
Do you think the uptake of EV's (based on batteries) is likely to be affected significantly by competition with hydrogen-powered vehicles?	Both battery and fuel cell electric vehicles will play a role out to 2050.
Should this scenario assume that some industries are contracting, for example, coal mining and gas exports?	The main implication of the scenario is the impact on renewable electricity generation and transmission required to produce hydrogen. Neither coal mining or gas exports are significant drivers of electricity consumption so there would be minimal impact on the ISP with these industries contracting. Both export industries are under long-term contracting arrangements and there appears to be no overarching policy drivers to indicate these sectors will reduce.
4.3 DOMESTIC EMISSION TARGETS AND REDUCTION	
Do you believe AEMO should implement high-level, state-based emission targets in any scenarios, if not legislated?	All Australian States and Territories have set net-zero emission ambitions by, or before, 2050. Energy Networks Australia thinks it is appropriate for the AEMO scenarios to include these ambitions.
4.13 GAS MODELLING	
Do you have any specific feedback on the inputs and assumptions documented for gas modelling in the Draft	This seems like a reasonable set of assumptions.

2021-22 Inputs and Assumptions workbook?	
4.14 HYDROGEN MODELLING	
Grid-connected hydrogen is proposed to only be modelled in the Export Superpower scenario; in other scenarios any hydrogen is expected to be either insignificant or produced off-grid. Does this give sufficient coverage?	Hydrogen may replace domestic use of natural gas in other scenarios too, it does not necessarily need to link to exports Hydrogen could also be produced from SMR + CCS and this is at similar cost to green hydrogen (as per Frontier economics analysis for Gas Vision 2050) The amount of electricity required for the amount of hydrogen in the Export Superpower scenario indicates it is 4 to 5 times as much as currently provided by the NEM. It is likely that export projects will be based in regional areas that are not grid connected and as such will focus on dedicated renewables for those export projects. Both dedicated and grid-connected renewable electricity will be used for domestic hydrogen consumption so the scenario should consider a proportion of grid connected electricity that will be used to produce hydrogen for the domestic market. Hydrogen can play a major role in stabilising the electricity grid. As grid-connected electrolysers, it can be used as a variable load that could be switched off in periods of high demand and switched on in periods of low demand – similar to large scale batteries. The non-grid connected hydrogen production for domestic use could subsequently be used in fuel cells to generate electricity.
In the Export Superpower scenario, decarbonisation ambitions lead to transitioning gas distribution networks to 100% hydrogen by 2045. Do you have any feedback on this approach?	All Australian States and Territories have signed up to net-zero emissions by, or before, 2050. It is unclear why the ISP assumption would bring this ambitious target forward by an additional five years. The pathway to transitioning distribution networks should be considered in the scenario. For example, a fairly flat demand profile would be required for an industrial customer but a daily and seasonally variable consumption would be required for residential customers. This demand profile would affect the role of electricity transmission networks and storage. The scenario also appears to include a high amount of electrification of gas services. Replacing gas with hydrogen could deliver decarbonisation goals, without additional electrification (other than that needed to operate electrolysers).
In the Export Superpower scenario, domestic hydrogen consumption is approximately equal to export until 2040, at which	This assumption appears inconsistent with the above assumption of transitioning networks by 2045. Energy Networks Australia considers that hydrogen exports could be supported by dedicated renewable electricity generation and may not be grid connected.

point domestic demand is largely saturated and export becomes the dominant cause of growth in demand. Do you have any feedback on the suitability of this trajectory?	
Do you have feedback on the penetration of battery and fuel-cell electric vehicles in the scenario collection?	No comment
AEMO has selected PEM electrolysers as the preferred technology in this scenario, due to decarbonisation targets (preferencing green hydrogen), higher levels of flexibility in the operation of the assets, and notable investment activity in the market. Do you have any information that may indicate this assumption should be changed?	This assumption appears fine for the purposes of the ISP, which needs to look at meeting the whole demand with electricity. However, gas rich regions with suitable CO_2 storage locations may produce blue hydrogen which might subsequently be mixed within the national gas pipeline infrastructure and this could reduce the level of renewable electricity required for the scenario.
Do you have any feedback on the cost of electrolysers, the efficiency of electrolysers, or the rate of cost reductions projected into the future?	There are a range of cost projections for hydrogen production with the Technology Roadmap signalling a production cost of $2/ kg hydrogen. This will require cost reductions of electrolysers, increased utilisation rates and cost reductions of renewable energy generation. The cost of the balance of plant – and its potential to reduce over time - needs to be considered as well. Three factors: capital, electricity price and utilisation. The electricity price and utilisation will depend on whether the electricity is sourced on grid or off grid. If on-grid – significant electricity storage issues need to be considered
The electrolysers are assumed to have a fixed minimum baseload of 4.5% of their total capacity, even when they are not producing hydrogen. Do you have information that may	This assumption appears reasonable.

indicate this assumption should be changed?	
Nine ports are proposed as candidates for the 2022 ISP expansion to produce export hydrogen. Do you have feedback on these candidates and their suitability over other options for hydrogen hubs?	No specific comments on the proposed ports.
Water availability near the candidate export ports has been screened. Do you have any feedback on the assumed classification of fresh water being likely to be available or unavailable or desalination being required? Information that could help resolve the water availability at ports would be highly appreciated.	The "Hydrogen: Energy of the Future" scenario in the Deloitte report supporting the National Hydrogen Strategy showed that Australia could produce 34.06 Mt of hydrogen per year in 2050 to cover its domestic use and potential export. This is significantly higher than assumed in Export Superpower scenario. (http://www.coagenergycouncil.gov.au/sites/prod.energycouncil/files/publications/documents/Erratum%20-%20COAG%20report%20_Accessible%20version.docx) Water availability varies widely across Australia. According to the National Hydrogen Strategy, the amount of water that could be consumed could *be equivalent to about one-third of the water used now by the Australian mining industry*. While this is significant, this should be placed in context. In 2018/19 , Australia's total water use was 76 GL, while the use in the mining industry totalled 1.1 GL. (Source: Australian Bureau of Statistics – Water Accounts: Australia 2018/19 - https://www.abs.gov.au/statistics/environment/environmental-management/water-account-australia/latest-release#summary-indicators). One third of that represents approximately 0.5 per cent of Australia's total water consumption.
The cost of desalination is assumed to be $0.05 per kilogram of hydrogen based on Australia's National Hydrogen Strategy. This is a small contribution to overall cost, and it is proposed that the electricity demand would likely be immaterial in the scale of Export Superpower scenario (when compared to electrolyser demand). Do you	This simplification is consistent with the National Hydrogen Strategy (page 12) and is acceptable.

think this is an acceptable simplification?	
It is assumed that only a small amount of hydrogen storage will be required at the ports for operational uses, and as such, the cost associated with this storage is immaterial. Do you agree with this approach?	Both LNG exports and domestic consumption of gas are seasonal. The domestic gas consumption for Victoria is shown in the light blue line in the figure below. This indicates that more than twice as much gas is used during winter compared to summer, so this gas (or hydrogen) needs to be stored to meet these seasonal demands.  Note: *Total electricity includes electricity from gas and renewables, total gas includes gas used for power generation. Total consumption removes this double count. Source: AEMO data, Deloitte Access Economic analysis (2019), Energy Networks Analysis (2020) Energy Networks Australia suggests that the scenario considers a similar level of energy storage for hydrogen to continue to meet these domestic seasonal demands.
Other comments	The assumption that electricity for hydrogen will be grid connected may undermine the cost competitiveness of hydrogen. This cost is reliant on balancing three factors: capital cost of plant, utilisation of plant and cost of renewable electricity. The assumption that electricity is transported to ports where hydrogen is formed. However, it may be more appropriate to consider creating hydrogen at the renewable electricity resource (e.g. REZs) with hydrogen being piped to ports, as this may be more cost effective. Hydrogen production from steam methane reforming (or coal gasification) combined with CCS is also an option for hydrogen. This will allow different regions to produce hydrogen that do not rely on the identified REZ, and would reduce the demand on electricity infrastructure for hydrogen production. The Frontier Economics analysis for Gas Vision 2050 showed that using hydrogen (either blue or green) was at similar cost but at half the cost of electrifying the gas load.