S&C ELECTRIC COMPANY
Excellence Through Innovation

141 Osborne Street
South Yarra VIC 3141
Australia

Mr. Craig Price
Australian Energy Market Operator
530 Collins Street
Melbourne
Victoria 3000

Our Ref: JC 2018-054

28 February 2018

Dear Mr. Price,

S&C Electric Company response to the AEMO Integrated System Plan

S&C Electric Company welcomes the opportunity to provide a response to the Integrated System Plan, covering the coordinated development of the transmission networks in the National Electricity Market.

S&C Electric Company has been supporting the operation of electricity utilities in Australia for over 60 years, while S&C Electric Company in the USA has been supporting the delivery of secure electricity systems for over 100 years. S&C Electric Company not only supports the "wires and poles" activities of the networks, but has delivered over 8 GW wind, over 1 GW of solar and over 45 MW of electricity storage globally, including several battery projects in Australia.

S&C Electric are particularly interested in facilitating the development of markets and standards that deliver secure, low carbon and low cost networks and would be very happy to provide further support to the Australian Energy Market Operator on the treatment and potential of emerging technologies and approaches.

Yours Sincerely

Dr. Jill Cainey
Global Applications Director – Energy Storage
Email: jill.cainey@sandc.com
Mobile: 0467 001 102

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General Comments

Does the Integrated System Plan have "teeth"?

The Integrated System Plan (ISP) will be essential to ensure that the system develops in an efficient and cost-effective manner and we welcome the plan and fully support AEMO in the development of the plan.

We are concerned that the plan is currently a "nice idea". There is no requirement for the plan to be adhered to or that TNSPs need to ensure that their individual plans fit within or comply with the ISP. Many jurisdictions are exploring an over-arching "System Planner" role, an entity in the electricity system that not only has the necessary oversight to ensure that networks (at all levels) develop in an efficient and coordinated manner, but that have the necessary powers to require the development to proceed as planned (e.g. UK National Infrastructure Commission, UK IET System Architect).

AEMO undertakes valuable work in the planning space and the ISP adds to that portfolio, but it isn't clear how well-established the links between the Australian Energy Regulator, who oversees the RIT-T process, and the AEMO ISP, is or will be. For example, Figure 24 (page 50) gives excellent examples of good and bad approaches and it is not clear how the "not coordinated" approach will be avoided, if there is no mandated or regulated requirement to follow the plan.

Clearly AEMO have a significant role in the overseeing the Victoria network, but Victoria is the only state where AEMO has that role. That role is unlikely to be expanded into other states, but that would be one way to ensure development proceeded in line with the plan.

The ISP will need to be adjusted regularly for changes in politics at the Federal and state level and we hope the ISP will be part of the annual suite of planning reports delivered by AEMO.

Identifying REZs

While it is great to identify regions where the transmission network needs reinforcing by indicating where REZs are located, care is needed that in signaling these areas as high renewable resource zones, that negative impacts in local communities are avoided.

Impacts are many and varied, from worries about the deployment of renewable generation, the proliferation of pylons and wires and the potential pursuit of landowners by developers keen to lock up options to develop in these highly favourable resource regions.

Local councils with REZs in their region may need increased support and resources to deal with the consenting process for renewable generation projects etc.

As was seen in the UK when the Transmission System Operator (Market Operator) announced its requirement of 200 MW of Enhanced Frequency Response, this resulted in increased pressure on network operators (particularly at the distribution level) to process the 20 GW of applications for battery storage, well in excess of what was actually required by the tender and likely the result of a single proposed asset generating multiple connection applications in multiple regions as developers sought to locate an appropriate connection.

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It also resulted in some developers pursuing landowners with land close to network assets (and indeed some landowners pursuing developers) to secure land early. This has led to networks becoming constrained by "ghost" projects, that have yet to be built, since once a connection offer is accepted, the network has to hold that capacity ("grid blocking") as taken and there is no time limit on the life of the agreement. There is also no need for the developer to demonstrate how advanced the project is in terms of planning or if the project is progressing.

The Role for DERs

Care is needed to ensure that the true benefits and limitations of DERs to offer system support are recognised. Small-scale (residential) behind-the-meter batteries for instance cannot provide sub-second frequency response or black start. Larger-scale Commercial and Industrial (C&I) behind-the-meter assets, may be able to offer system support services.

DERs will always be operated according to the priority of the owner, not the system and need to be viewed with caution.

Also there is a range of uptake scenarios for behind-the-meter batteries, which run the full gamut of exponential growth, with more recent industry report from the US suggesting no significant activity for a further five years – this is not withstanding the recent announcements in South Australia (again indicating the strong influence of policy on the development of the electricity system).

Role for old Transmission Network

As large-scale thermal generation plants retire what will happen to those transmission connections that are no longer needed? Can they still be used, as at Liddell, or will they mostly lie idle? Could they be used for large-scale storage projects, which do not have to be co-located with variable generation (although it may need to be balanced with regional variable generation)? There are also other storage technologies beyond batteries, such as liquid air energy storage, that does use a turbine to generate electricity in the expansion phase (export) of the storage process. There are bulk storage technologies that may not be fast, but are long duration.

This old network, if still viable, needs to be part of the plan, with priority given to developing energy projects that can utilise those existing network assets.

Synchronous Generation

Obviously, the provision of inertia/primary frequency control is under review by both AEMO and the AEMC. But if the provision of inertia is (mandated and) appropriately valued, then this may allow some plant to remain on the system for longer.

New Interconnectors

Interconnection is a source of flexibility, which the NEM will need in the future. Interconnectors are not the only source of flexibility, since smaller-scale gas engines, storage and demand-side response, also provide flexibility. A mix, as AEMO states, of all of these will be required, but determining the proportions of each in terms of delivering system flexibility economically, will be challenge, particularly in the current

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market structure (settlement periods, 6 second FCAS versus “1 second FCAS”, FCAS more generally, illiquidity in the Wholesale Market).

Figure 19 (page 46) notionally introduces some new interconnectors. It would be a concern if both the South Australia to Queensland and the Davenport to Mount Piper interconnectors terminated at approximately the same point in South Australia. There should be diversity in the location of the end points of the interconnectors.

Response to Questions

1.1 The material questions the ISP seeks to address are in Section 1.3.1. Are there any other questions the ISP should address?

1.2 The scenarios the modelling will use to inform the ISP are outlined in Section 1.4. Recognising the time limitations to produce the first ISP in mid-2018, are these suitable scenarios to address at a high level? Should these be expanded in more detailed analysis following the first high level ISP?

It is after the deadline to provide input into the modellings aspect of the ISP, but it may be valuable to explore the approach of the GB Transmission System Operator and their annual Future Energy Scenarios (FES), which includes a matrix of emissions reduction and economic drivers:

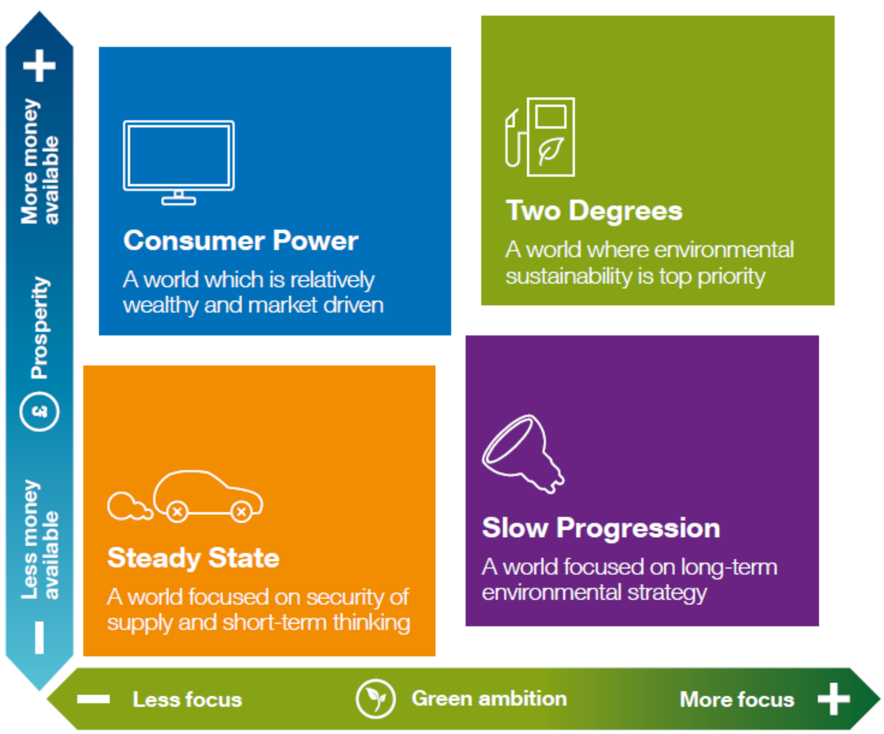

Figure 1: The 2017 National Grid FES Scenario Matrix (page 10)

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The FES 2016 addressed the potential for energy storage at all scales, so that may also be worth assessing the output of this particular report, particularly in comparison with page 57 of the ISP (pages 104-114 at: http://fes.nationalgrid.com/fes-document/fes-archives/ or a less detailed assessment in FES 2017 on page s 65-66, since storage is now rolled into the routine modelling for the FES).

2.1 What are the key factors which can enable generation and transmission development to be more coordinated in future?

It is difficult to know who in the NEM has the best visibility of where generators want to connect. It is probably the TNSP, but that information can't be shared with generators nor is there any locational investment signal (other than network, no network or constrained network) to "help" developers target a particular region or zone.

It seems like some sort of commitment from developers is needed ahead of a major investment. In the UK there are connection charges and the party that triggers reinforcement has to pay the full cost of the reinforcement – a huge disincentive to be that project. The other disadvantage with the UK approach, is that after the triggering party has paid for the new network, new parties may then connect to the increased capacity and "free-ride" (not pay for the benefit). Indeed, existing connectees on what was a constrained network, may also "free-ride" on the investment of the triggering party. There has been much work in the UK to try and resolve this, without much success largely because developers do not wish to share information on their new and commercially sensitive projects. It is difficult to see how any attempt to coordinate the development of new transmission network can work without the open and transparent participation of developers.

A new approach is needed to funding to securing interest in new network is needed. The UK model does provide some options for locational signals through the connection application and commissioning fee, but there are other problems with the UK approach (see above).

If a TNSP planned to connect a REZ, could the option to connect in the REZ be auctioned to developers to secure a commitment to connect and thus prevent a stranded asset? I'm not sure that developers would be willing to pay, if this has not been the model in the past.

There needs to be a balance between local and central generation – the REZs are essentially sticking to the centralised generation model, with electricity trickling down to consumers at the end. The new local model would see generation deployed in a much more distributed fashion, supporting local markets etc. Care is needed to strike a sensible balance between the centralised and distributed model and it is difficult to see where that balance will sit in 10 years time.

The ISP states that currently demand is forecast to be flat and that energy efficiency is a significant driver in that flat demand. It is also possible that midday solar at the distributed level is masking changes in demand. However, increased use of air conditioning, deployment of electric vehicles and the advent of sustainable water approaches, which might see pumps in every home, will drive up demand, overtaking and energy efficiency improvements. Typically, modest increases in projected demand are seen globally, but determining the exact drivers of demand or perceived demand by the system operator needs careful assessment.

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Large-scale Demand Side Management is likely to be a major source of system support. National Grid's Power Responsive programme (http://powerresponsive.com/) anticipates that up to 50% of transmission system support services will be provided by the Demand Side by 2020. National Grid are not considering domestic-scale Demand Side Response since the loads are currently small and aggregation is uneconomic. The Power Responsive programme has driven significant change in the system service specifications and contract arrangements offered by National Grid, to facilitate participation by Large C&I providers. Similar work is needed by AEMO and AEMC to ensure that the market arrangements are favourable to Demand Side Approaches.

Stand-alone Power Systems (SPS) deliver electricity more reliably and at lower cost to all customers, not just those remote customers on the SPS. In this case, taking customers (**demand**) off the network in remote areas is more economic than keeping them connected to long lines. However, the ISP envisages building more long lines to connect **generation** in remote areas. This seems slightly perverse and it is difficult to see why for demand not being connected to long lines is better for all, versus connecting generation to long lines is better for all (noting that an SPS should still be part of the network).

AEMO will need to ensure that SPSs are not replacing lines that will be important to connect REZs.

There also needs to be coordination between the investment in the distribution network and the transmission network. The ISP is only concerned with the transmission network, but in most jurisdictions the TNSPs and DNSPs are working together to deliver the future system.

3.1 Does this analysis capture the full range of potential REZs in eastern Australia?

Tidal or wave generation is not considered nor is coastal pumped hydro energy storage, accepting that both are not yet common.

3.2 What other factors should be considered in determining how to narrow down the range of potential REZs to those which should be prioritised for development?

Are they close to a potential new interconnector, so maximizing the benefits of constructing new transmission lines?

3.3 What are the potential barriers to developing REZs, and how should these be addressed?

Even if an area is designated a REZ, it doesn't mean generators will come. And even if transmission network is built, it doesn't mean generators will come. The absence of any price signal for location makes it difficult to see what would motivate a developer, other than the resource alone.

As mentioned above in general comments, local communities and the planning and consent process may be an issue in terms of delays and barriers.

4.1 Have the right transmission options been identified for consideration in the ISP?

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Probably.

4.2 How can the coordination of regional transmission planning be improved to implement a strategic long-term outcome?

The ISP needs to be more than “nice to have”, it needs to carry some regulatory weight to ensure that transmission development occurs in a coordinated way.

The role of the distribution network, particularly given the perception that DERs will be supporting the wider system, needs to be considered. Especially, the points where the distribution network connects with the transmission system.

4.3 What are the biggest challenges to justifying augmentations which align to an over-arching long-term plan? How can these challenges be met?

Addressed elsewhere

4.4 Is the existing regulatory framework suitable for implementing the ISP?

Gaining approval to invest in new transmission lines from the Regulator takes time. It is not clear whether the long lead times are due to the regulatory process or whether, if that regulatory process is ignored, the planning/consenting and construction of new network is relatively quick or on a similar time scale as for the development of a renewable generation project.

The RIT-T and RIT-D processes do not seem to be delivering what is required. New processes, that recognise the need for investment for forecast generation, as well as demand are needed. Plus, the recognition that both demand and generation place technical constraints and costs on the system, so appropriately apportioning the benefits and costs needs to be addressed. The ability to use a price to signal a location to connect, either as demand or generation (and at the distribution and transmission level) would be helpful.