Integrated System Plan; Action Plan

Energy Security Board 2018

The Energy Security Board has five members:

Kerry Schott AO	Independent Chair
Clare Savage	Independent Deputy Chair
Paula Conboy	Chair of the Australian Energy Regulator
John Pierce AO	Chair of the Australian Energy Market Commission
Audrey Zibelman	CEO of the Australian Energy Market Operator

Integrated System Plan: Action Plan

Executive Summary

At the COAG Energy Council meeting on 10 August 2018 the ESB was requested to report in December 2018 on:

- how the Group 1 projects in the Integrated System Plan can be delivered as soon as practicable.
- how Group 2 and 3 projects should be progressed, and
- how the ISP would be converted into an actionable strategic plan.

The ESB Chair was to provide this report.

The 2018 Integrated System Plan is introduced in Section 2 . This plan is based on minimising costs and meeting the physical requirements of the system as aging (mainly coal fired) generators retire and new generation enters the system. The new generation has different characteristics to the generation that is retiring. The plan covers the period to 2040 and identifies investments in the grid that are required as the system transitions. The investments are characterised in three groups: near (Group 1), medium (Group 2) and longer term (Group 3).

The near term Group 1 projects are to:

- Increase capacity between New South Wales and Queensland (QNI) and Victoria (VNI) by 170-460 MW (minor upgrade to QNI; minor upgrade to VNI)
- Reduce congestions for existing and committed renewable energy developments in both western and north-western Victoria
- Remedy system strength in South Australia.

The completion target for the Group 1 projects is as soon as practicable.

The five medium term Group 2 projects identified need to be implemented by the mid 2020's. In this same time frame AEMO will coordinate work with project proponents on a design for transmission networks to support the strategic pumped hydro storage initiatives of Snowy 2.0 and Tasmania's Battery of the Nation. The Group 2 projects are:

- New transfer capacity between New South Wales and South Australia of 750MW
- Increased transfer capacity between Victoria and South Australia of 100MW
- Increased transfer capacity between Queensland and NSW of 378MW
- Efficient connection of renewable energy sources through maximizing the use of the existing network and appropriate route selection
- Coordinate Distributed Energy Resources in South Australia.

In the longer term to the mid 2030's and beyond the grid is to be enhanced by:

- Increased capacity between New South Wales and Victoria of 1800 MW
- Efficiently connecting renewable energy sources through additional intra regional network development and upgrades

Many of the Group 2 and 3 projects are major works and more careful consideration of them is warranted. No one expects 20 year planning forecasts to be accurate at all times but future ISPs will allow updates for better information , ongoing developments and the continued market transformation. Various suggestions for how the next ISP might be refined are included in the paper and it is anticipated that an ISP will be done every two years with ongoing updates for any material changes that occur in the system. With refinement it is expected that the ISP will provide the information directly needed for the first stage of the Regulatory Investment Test for Transmission (RIT-T). This will streamline this regulatory process for the transmission companies in the future.

The way in which transmission investments are planned and delivered by transmission companies is examined in Sections 3 and 4. The way these projects can be done in a more timely manner comes down to three things. First if the project is managed so that design, early works, equipment ordering and minor construction are done concurrently rather than sequentially significant time (of the order of 12-18 months) can be saved. The risk of regulatory rejection of the project however means that these costs may not be covered for the company and this risk needs to be managed. The ESB suggests consideration be given to a fund that could underwrite this work in carefully specified circumstances and hence cause the risk to be shared between that Fund and the company. The second matter concerns the time taken around regulatory processes. Once the RIT-T is conducted the ESB suggests that the AER's preferred option assessment, dispute assessment (if any), and consideration of the revenue recognition application be managed concurrently for Group 1 projects. This step would save 6-8 months and a recommended rule change is included as an Appendix and is recommended for immediate action. This rule change is intended to apply to the QNI and VNI Group 1 projects only at this stage, extension to other ISP projects is to be considered at a later stage. The ESB also suggests that all investment projects in the ISP be considered as for fast tracking by the AER. This may require a rule change and more examination in 2019. The third matter is unnecessary delays in planning approvals. The ESB recommends that each jurisdiction moves urgent and critical ISP projects into the highest status available for planning assessments under their own state laws.

The delivery of the Group 1 projects is being tracked by AEMO. With the recommendations made in this paper it is possible to bring all the Group 1 projects in by the dates required.

- The SA system strength project is running to the required schedule.
- The QNI project needs to be speeded up by at least 18-24 months. The regulatory rule change recommended will save 6-8 months if implemented; the more timely early works (already assisted by the NSW Government) along with the possibility of designing and ordering equipment before regulatory approvals are finalised will allow the required completion date to be achieved. Running the build concurrently with the regulatory process is risky but in effect saves 12-18 months. Highest priority planning status should also be sought to ensure that planning delays are not the reason the required date is missed.
- The VNI upgrade needs to be speeded up by about one year. The regulatory rule change at Appendix 1 will save 6-8 months. Achievement of highest priority planning approval status in both New South Wales and Victoria is required, particularly in New South Wales. If Commonwealth environmental approvals are also needed (which may not be necessary) the coordination of these processes will be critical.
- The NW Victorian renewable integration work can be done in less time with more expeditious planning approvals and early commencement of works where possible. Early land/easement acquisition is not possible without planning approvals making planning the critical path on this project. Extending the rule change in Appendix 1 to this Group 1 project may be advisable and will be considered within the terms of Recommendation 6.

Being further out in time Group 2 and 3 projects are less certain in their costs and benefits than the Group 1 projects. In many cases they are also more substantive in cost. Nevertheless, early works and cost-benefit analysis for these projects has already commenced and AEMO will continue to monitor progress.

The last section of the paper discusses Renewable Energy Zones (REZs). In the ISP there are 34 REZs identified and assessed based on resource availability and proximity to the existing grid. Optimal development areas in the immediate term are:

- NSW: Central Tablelands (wind and solar) and Southern tablelands (wind)
- Queensland: Darling Downs and Fitzroy (wind and solar)
- SA: Northern (solar) and Mid-North (wind)
- Tasmania: North West (wind)
- Victoria : Mayne (wind).

The Murray River and Wester Victoria REZ's are already experiencing committed renewable developments and large amounts of additional generation is expected in the near term. RIT-T tests are underway to assess the transmission development required to support these REZ's and to reduce the costs of congestion.

AEMO and the transmission companies are receiving unprecedented volumes of connection enquiries and the main concerns are connection, congestion and access. These issues need further consideration as they are complex, interrelated and their implications for pricing and market design go well beyond specific REZ issues. Several recommendations are made about these issues and the ESB would like to bring recommended resolutions of them to the COAG Energy Council in 2019.

Recommendations

Recommendation 1: The ESB recommends that all Group 1 projects in future ISP's be fast tracked if they are not already categorised as contingent projects. Rule changes that may be necessary should be brought to COAG Energy Council by June 2019.

Recommendation 2: The ESB recommends that transmission companies consider whether Group 2 and 3 projects meet contingent project requirements and if so work with the AER to enable that status to be conferred.

Recommendation 3; The COAG Energy Council ask the ESB to explore setting up a Fund that could be used to 'underwrite' expenditures on Group 1 projects that are time critical .The issues to be further examined by the ESB include the size of the fund; the source of the finance; criteria for the assessment of what proportion of expenditure to underwrite; what undertakings should be required from the transmission company before any activation of the underwriting. A report on this initiative should be brought to COAG Energy Council by mid 2019.

Recommendation 4: That all governments in the NEM consider moving Group 1 ISP projects to the highest priority planning approval status.

Recommendation 5: That the ESB submit a rule change to the AEMC as set out in Appendix 1 to enable concurrent treatment of the preferred option assessment, any dispute, and a revenue recognition application following the RIT-T. Initially this rule change is to apply only to QNI and VNI.

Recommendation 6: That the ESB consider what criteria would need to be met for the rule change in Appendix 1 to be applied to other ISP projects (beyond QNI and VNI) and to report back to COAG Energy Council on this issue by mid 2019.

Recommendation 7: If a Group 2 or 3 Project is considered by AEMO and the ESB to be lagging behind its required timing the AEMC should be requested to use its Last Resort Planning Power to direct a company to commence its RIT-T process.

Recommendation 8: Rule changes should be prepared and lodged by AEMO with the AEMC to have the NTNDP replaced by the ISP. Rule changes should also be lodged that require the ISP to be developed every 2 years with updates in between plans if there is a defined material event. AEMO should issue guidelines to stakeholders on how and when an update to the ISP would be done.

Recommendation 9: The ESB should work with AEMO to ensure that refinements to the inaugural ISP suggested in this paper are included in future ISPs.

Recommendation 10: The ESB should bring back to COAG Energy Council any rule changes, if required, to enable the ISP to identify the need and set of credible options to meet that need and replace of the current Project Specification Consultation Report in the RIT-T.

Recommendation 11: That the ESB examine the possibility of a Fund to extend transmission assets to connect to Renewable Energy Zones with the cost of this transmission progressively recovered

from consumers if and when utilisation increases. The required size of the finance, the source of funds, and how funds should be recovered and managed should be part of the examination.

Recommendation 12: The ESB recommends that as part of their work they report back to the COAG Energy Council in 2019 on the REZ connections, access and congestion - and options for addressing them.

1. Context

At the COAG Energy Council meeting on 10 August 2018 the ESB was requested to report in December 2018 on:

- how the Group 1 projects in the Integrated System Plan can be delivered as soon as practicable.
- how Group 2 and 3 projects should be progressed, and
- how the ISP would be converted into an actionable strategic plan.

The ESB Chair was to provide this report.

2. An Introduction to the 2018 ISP

The ISP issued by AEMO in July 2018 forecasts the system developments in for the National Electricity Market (NEM) for the next 20 years and identifies the transmission investments that will support least cost portfolio of resources necessary to meet consumer demand over this period. It replaces an annual National Transmission Network Development Plan which tended to sit on the shelf unused and not be activated. The ISP is intended to be activated. It is a plan based on minimising costs and meeting the physical requirements of the system over that time as aging generators retire, and new resources enter the system. The new resources have different attributes and capabilities from the generation being replaced and is frequently in different localities. What is not changing however is the essential need for cost effective and reliable power, the capital-intensive nature of the transmission system and its physical requirements.

A number of different scenarios are investigated using specified assumptions about such matters as demand, the increase in distributed energy resources, costs of different generation technologies, fuel availability and storage.   The seven scenarios examined were:

- Two base cases: Neutral and neutral with storage
- Three change scenarios: slow change, fast change, and high Distributed Energy Resources
- Two scenarios focussing on key risks or opportunities: increased role for gas, and early exit of coal fired generation.

The principal assumptions used related to five matters

- Retirement of coal fired generators at the end of their technical life, or as advised by owners
- Operational demand by residential, commercial and industrial customers
- The cost and performance of various supply options across a range of different technologies
- A range of potential system investments
- Government policies with a direct impact on the power system

The ISP also took a further five factors into account.

- The availability of gas reserves, resources and pipeline capacities are recognized. These influence both the cost and availability of gas as a fuel for generation.
- The maximum renewable energy potential and constraints in each region. The quality of these renewable resources can be degraded through excessive co-locations, transmission capacity, and costs of augmenting the system.
- Diurnal and seasonal weather patterns. The hour by hour profile of renewable energy output is related to its location and related weather patterns.

- The need for some minimum of synchronous generation in the system. This is an effective constraint where insufficient synchronous generation will cause non-synchronous renewable generation to be curtailed.
- The levels of Distributed Energy Resources (DER) coordination were varied for each of the scenarios examined. DER can be used to meet system needs, rather than being passive, but only if it is coordinated.

There is detail about the approach, the scenarios and the assumptions used in the 2018 ISP set out in that document. All parties within the NEM should examine it carefully as the planning of transmission it has implications for all types of participants connected to the NEM and to consumers, not just to network service providers.. The power system is integrated and what happens with supply, demand, storage, distribution and transmission are all related. The ISP is a document of importance to customers, generators, distributors and of course transmission companies.

The aim of the ISP is to set out an integrated path for the development of the power system. The 2018 ISP identified investments in the grid that are needed to accommodate the changes in the power system that are both underway and expected. These investments were categorised into three groups: near term (group 1), medium term (group 2) and longer term (group 3).

In the near term three Group 1 projects are identified with a total cost of between $450-$650million with benefits for consumers to be realised upon commissioning and well then well beyond the 20 year 2018 ISP period. The five Group 1 projects are:

- Increase capacity between New South Wales and Queensland and Victoria by 170-460 MW (minor upgrade to QNI; minor upgrade to VNI)
- Reduce congestion for existing and committed renewable energy developments in both western and north-western Victoria
- Remedy system strength deficits in South Australia.
-

Group 1 projects are found to be necessary under all scenarios and their completion targetis as soon as practicable.

The five medium term Group 2 projects identified need to be implemented by the mid 2020's. In this same time frame AEMO will coordinate work with project proponents on a design for transmission networks to support the strategic storage initiatives of Snowy 2.0 and Tasmania's Battery of the Nation. The Group 2 projects are:

- New transfer capacity between New South Wales and South Australia of 750MW
- Increased transfer capacity between Victoria and South Australia of 100MW
- Increased transfer capacity between Queensland and NSW of 378MW
- Efficient connection of renewable energy sources through maximizing the use of the existing network and appropriate route selection
- Coordinate DER in South Australia.

In the longer term to the mid 2030's and beyond the grid is to be enhanced by:

- Increased capacity between New South Wales and Victoria of 1800 MW
- Efficiently connecting renewable energy sources through additional intra regional network development and upgrades

Many of the Group 2 and 3 projects are major works and more careful consideration of them is warranted. Many of the projects contemplate orderly coal retirements. However, as AEMO notes that the need for some of projects will be accelerated if coal plants retire earlier than expected. The ESB notes that AEMO has commenced work to evaluate the implications of these changes and to recommend changes as an update to the ISP.

No one expects 20 year planning forecasts to be accurate at all times but future ISPs will allow updates for better information ongoing developments and the continued market transformation. What is clear however is that at this moment in time the Group 1 projects have more certain underpinnings than those that are later in the 20 year planning period. But Group 2 and 3 are also projects that must be further evaluated. This must begin immediately.

3. Delivering ISP Projects

The extent of change in the electricity system means that timely delivery of the ISP projects is critical for an orderly transition. The ESB has identified stages in project delivery where a more efficient and expeditious approach would enable more timely delivery.

Transmission projects identified in the ISP appear in plans that individual transmission companies prepare - their annual planning reports. Depending on where the project arises in a business's regulatory cycle, these projects either:

- form part of the capital expenditure allowance for a revenue determination, or,
- if the timing or need for the projects is uncertain at the time the revenue determination is made then these projects may be included in the revenue determination as contingent projects.

Where a project is identified as a contingent project (within a revenue reset period) the AER does not immediately include revenue for that project in its revenue determination for the period but specifies trigger events that need to be met before an application for revenue for the project can be made by the network service provider. However, once the defined triggers are met, the business can apply to the AER for the revenue required to efficiently undertake the relevant project. The project then becomes 'actual' and and the businesses' revenue allowance is adjusted to reflect the expenditure associated with the contingent project. If a project is not identified as a contingent project and is not required as the result of a pass through event occurring or a very significant change to capital expenditure requirements that occurs within the revenue reset period, then revenue for it cannot be considered until the next revenue reset period which may be five years into the future.

Recommendation 1: The ESB recommends that all Group 1 in future ISP's be fast tracked if they are not already categorised as contingent projects. Rule changes that may be necessary should be brought to COAG Energy Council by June 2019. In addition, ***Recommendation 2: The ESB recommends that transmission companies consider whether Group 2 and 3 projects meet contingent project requirements to the extent they are not otherwise captured by their revenue requirements and if so, work with the AER to enable that status to be conferred .***

If a project is not already included in a Transmission company's revenue allowance the steps to project delivery are clear.

- First the project must undertake early work so that it is sufficiently specified to enable cost and benefits to be calculated and assessed. This early work of project specification can be expensive as it involves such matters as route selection (and maybe geotech work), equipment specification and design, and preliminary environmental investigations.
- The second stage in delivery, after early works are completed and the project is specified, is regulatory approval. The cost benefit analysis (via the Regulatory Investment Test for Transmission (RIT-T)) must be done. and subsequent approval achieved (under section 5.16.6 of the NER).
- The third stage of delivery, after regulatory approval, is to apply for revenue recognition approval. This important step, if successful, provides the revenue for the company to finance the project.
- The fourth stage, perhaps with some preliminary overlap with the stages above, is planning approvals within the relevant jurisdictions. This stage is often the longest.

Without both RIT-T and revenue recognition approvals the transmission company can be at risk of losing all its prior expenditure on the project, depending on how it is has managed it operating expenditure allowance. As a result, it is unlikely that a transmission company will proceed with major expenditure without such approvals.

Furthermore, if there is any chance of a dispute being registered and conducted, further expense and time is added to the process. The cost of early works on these projects, along with the cost of a RIT-T and revenue recognition approval may amount to tens of millions of dollars. And it is only after these approvals that equipment will be ordered, and construction begun. Planning approvals (state and federal) are also time consuming and expensive and there can be overlap and duplication in the environmental planning assessments between jurisdictions.

The upshot of these planning and regulatory procedures is that while it takes less than 24 months to design and commission a large-scale renewable generator, the time it takes to commission a reasonably straightforward transmission upgrade is closer to four or five years. The problem has been recognized by the market bodies and considerable work has been done addressing how the process can be streamlined. The matter has also been raised in consultations with the AEMC and industry; and recently with the ESB and industry participants. A number of ways to make the regulatory process more timely is addressed in the next section.

Project management suggests that for faster delivery a way needs to be found for tasks to be addressed concurrently and not sequentially as in the stages set out above. Both the South Australian and New South Wales Governments have taken steps down this path by assisting the transmission companies in their states with the risks they face in conducting early works for the project specification. In both cases Early Works for their Group 1 Projects have been partly ‘underwritten’ by the government. If the project does not proceed the company is not carrying the entire risk of losing its early works expenditure. A similar approach could be taken to allow the design and ordering of expensive equipment prior to regulatory approvals. Again, this takes some risk away from the company and moves some of it to government. In some cases, the size of the risk in the early ordering of equipment is significant. In the Queensland/NSW interconnector group 1 upgrade, the equipment cost is around $30 million and if this equipment is not to be used because the project fails the RIT-T it is a bespoke type of kit that cannot easily be sold or used elsewhere. This is an important point for the Queensland/NSW interconnector upgrade as the ordering of specifically designed equipment is on the critical time path.

Recommendation 3: The COAG Energy Council ask the ESB to explore setting up a Fund that could be used to 'underwrite' expenditures on Group 1 projects that are identified as time critical .The issues to be further examined by the ESB include the size of the fund; the source of the finance; criteria for the assessment of what proportion of expenditure to underwrite; what undertakings should be required from the transmission company before any activation of the underwriting. A report on this initiative should be brought to COAG Energy Council by mid 2019. The expenditure on early works and 'critical path' equipment could be brought forward by over a year with this step.

Assistance by government by granting the highest priority to ISP projects in the planning approval process would also be welcomed. There is no desire to override planning requirements, particularly in environmentally sensitive areas, but if Group1 ISP projects could be given a priority status by all governments because of the essential nature of the service that would hasten the process. This point is important for the NSW/Victoria interconnection Group 1 upgrade. The route of this upgrade from the La Trobe area to upper Tumut passes through national parks. While the route is already in use for transmission the area is environmentally sensitive. This comment is particularly relevant for the environmental assessments conducted by both state and federal bodies where anecdotal reports suggest there can be improvement by cutting out duplication. The timing of work on this line is difficult because the line is operational and hence can only be worked on when part of Snowy is not operating and is off for scheduled maintenance or during two shoulder periods throughout the year where use is low. This added pressure puts extra weight on the need for efficient planning. ***Recommendation 4: That all governments in the NEM consider moving Group 1 ISP projects to the highest priority planning approval status available under their own state laws.***

4. Conducting the Regulatory Tests

As well as the project management changes suggested there are also changes that can be made in the regulatory area to save delivery time and generally make the process more efficient. There are different changes that can be made and depend on the relevant group of ISP projects .These possible changes range from allowing post RIT-T processes (preferred option analysis, dispute notification periods and revenue assessments for contingent projects) to be run concurrently or scrapping RIT-T altogether for Group 1 projects to better integrating the ISP and the RIT-T analysis. The AER, the AEMC and the ESB have been considering these matters.

Allowing projects to proceed without a cost-benefit test is not ideal practice even when the ISP has found the project to be least cost from a system wide perspective. These are investment projects that customers pay for, so it is important that all participants feel the analysis of the project has been thorough. Such additional analysis could also examine project benefits in more detail and along with the ISP work make disputes less likely.

Finding ways to better integrate future ISPs with a rigorous cost-benefit analysis of investments is a key step in reducing the time it takes to deliver transmission projects.

The current cost-benefit analysis requires several key steps[1]:

- Identify a need for the investment, known as the identified need.
- Identify a set of credible options to meet the identified need and characterise the base case against which credible options can be compared.
- Identify reasonable inputs to include in the cost–benefit analysis.
- Quantify the expected net economic benefit of each credible option and identify the preferred or “best” option with the highest expected net economic benefit.

A key function of the RIT-T is that it provides transparency and confidence in the regulatory process by seeking stakeholder input. Stakeholder engagement and consultation is sought and there are multiple opportunities for stakeholders to be involved and provide input.

There are three stages in the consultation process:

- Project specification consultation report (PSCR) – this describes the identified need, its technical characteristics and the credible options to meet the identified need. Costs and constructions timeframes are set out. There is a minimum of 12 weeks consultation required.
- Project assessment draft report (PADR): if the proposed investment is going to proceed, a draft report providing a description of each credible option and an identified preferred option must be done within 12 months of consultation closing on the PSCR. There is then a minimum of 6 weeks consultation required for this report.
- Project assessment conclusions report (PACR): this must be published as soon as practicable after the consultation period for the PADR ends.

A number of parties are able to raise a dispute concerning particular components of the conclusions in the PACR. The dispute has to occur within 30 days of publishing the report. The AER has to decide to either reject the dispute or require amendments within 40 calendar days of the notice (this period can be extended by a further 60 calendar days).

It is only after this cost-benefit process (and any disputes) have been concluded that the AER will assess the capital expenditure for the project either through the usual revenue determination process (which can be 18 months long) or as a ‘contingent project’ (assuming the pre-set triggers are met) where the AER will have to be satisfied that the cost-benefit assessment has been successfully completed. Contingent projects are dealt with on a faster track, but this revenue determination can even so add up to 100 business days to the process.

The length of time it takes for projects to proceed to completion has been a matter of concern for the COAG Energy Council for some time. In response the ESB and the market bodies have come up with recommendations to stream line the process. The changes focus on the regulatory process after the RIT-T has been concluded and at this stage these changes are intended to apply to the QNI and VNI Group 1 projects. Crucial to streamlining the current regulatory processes will be early and frequent engagement with the AER throughout the RIT-T process.

[1] The AEMC’s final report for the Coordination of Generation and Transmission Investment Review and the AER’s Review of the RIT-T Guidelines both detail the current RIT-T process.

Wider application to other projects in the ISP should be considered during 2019 in the context of the AEMC's final report for coordination of generation and transmission investment and continued engagement with key stakeholders.

The proposed transitional rule changes for QNI and VNI (see Appendix 1) would allow a potential reduction of 6-8 months in the process. This is achieved by permitting concurrent treatment of a dispute, the preferred option assessment, and the revenue application. This is set out in the table below:

Objective of Proposed Rule Change	Mechanism for Achieving Change
• The three Post-RIT Regulatory Processes (dispute, preferred option assessment and contingent project revenue determination) are currently required by the rules to be undertaken sequentially. • The proposed rule changes would allow the AER to undertake the three processes concurrently, potentially saving 6-8 months[2].	• Allow TNSP to apply to the AER for preferred option analysis even if a dispute is on foot, however AER may only make a preferred option analysis decision after any dispute is resolved. • Allows contingent project revenue application to be made even if AER preferred option analysis is not complete, but clarifies that AER contingent project determination cannot be made until AER preferred option analysis is complete.

Given the nature of the rule changes proposed and the fact they only apply to the QNI and VNI projects, it is anticipated that they may qualify as non-controversial rule changes for the purposes of the National Electricity Law.

If this is the case and the ESB were to submit a rule change to the AEMC on this basis, the rule change process should only take 8 weeks to complete. ***Recommendation 5: That the ESB submit a rule change to the AEMC (for QNI and VNI initially) to enable concurrent treatment of the preferred option assessment, any dispute, and a revenue recognition application following the RIT-T.*** This change would allow concurrent treatment of the preferred option assessment, any dispute, and a revenue application to be determined. ***Recommendation 6: That the ESB consider what criteria would need to be met for the rule change in Appendix 1 to be applied to other ISP projects and to report back to COAG Energy Council on this issue by mid 2019.***

[2] The saving of 6-8 months is achieved by compressing the Post-RIT Regulatory Process. This will only be possible if (and this time saving assumes) the transmission company is able to involve the AER in the RITs as the RITs are undertaken

5. Progressing the Group 1 Projects

AEMO has been tracking the implementation of these projects. This is set out in the table and discussion below, with the NSW/Queensland (QNI) -NSW/Victoria (VNI) transmission upgrades treated as two separate projects, though both are important to the future reliability in NSW.

Project	**Expected RIT -T process without rules changes**	**Projected time for physical implementation**	**Expected completion**	**Required Completion**	**Impact of delay**
Q/NSW Upgrade (QNI)	2 years + Commenced Nov 2018	2 ¾ years	Dec 2022-Feb 24	December 2021	Reliability concerns in NSW
Vic/NSW Upgrade (VNI)	2 years + Commenced Nov 2018	3 years	Late 2022	December 2021	Reliability concerns in NSW
Western and North Western Vic Renewables Integ'n	Expected completion by August 2019 (if no disputes)	2-4 years	2024-25	2023	Delayed market benefits for consumers
SA System Strength	Not subject to RIT-T	1-2 years	Late 2020	2020	Continued directions in South Australia for System Strength

The QNI and VNI projects need to be complete and available for full service in time to assist in replacing the capacity lost with the closure of Liddell. AGL has announced and committed to Liddell closing in 2022, but has also announced a phased plan of new generation at the Liddell site to replace some of this capacity. . Liddell is expected to be available through summer and winter 2022 but will close before summer 2022-23. This would imply that Group 1 projects must be fully tested and commissioned before October 2022, assuming no other generation is built in NSW in this time period.

Liddell's fixed closure date means that maintenance will be limited; and the plant's already poor availability may deteriorate.

The Western and North-western Victoria renewable integration project needs to be completed as soon as practicable to minimise the extent and cost of constraints on renewable generators in that region. The extension of the commitment of the Victorian government to a renewable energy target increases the benefits of early completion. However, this project requires major new lines and a new transmission switching station. It is a reasonably complex project to deliver.

With the recommendations made earlier in this paper it is possible to bring all the Group 1 projects in by the dates required.

- The SA system strength project is running to the required schedule.
- The QNI project needs to be speeded up by at least 18-24 months. The regulatory rule change recommended will save 6-8 months if implemented and assuming the AER is able to engage with Transgrid during the RIT; the more timely early works (assisted by the NSW Government) along with the possibility of designing and ordering equipment before regulatory approvals are finalised will allow the required completion date to be achieved. Running the build concurrently with the regulatory process is risky but in effect saves 12-18 months. Highest priority planning status should also be sought to ensure that planning delays are not the reason the required date is missed.
- The VNI upgrade needs to be speeded up by about one year. The regulatory rule change at Appendix 1 will save 6-8 months. Achievement of highest priority planning approval status in both New South Wales and Victoria is required, particularly in New South Wales. If Commonwealth environmental approvals are also needed (which may not be necessary) the coordination of these processes will be critical.
- The West and North Western Victorian renewable integration work can be done in less time with more expeditious planning approvals and early commencement of works where possible. Early land/easement acquisition is not possible without planning approvals making planning the critical path on this project.

6. Group 2 and 3 Projects 2018 ISP

The ISP's Group 2 projects are required in the medium term to enhance trade between regions, provide access to storage, and support the extensive development of renewable energy zones. The Group 2 and 3 projects are also required to ensure system reliability and security once the existing coal plants retire. The proposed initiatives in Group 2 are of a larger scale and cost than those in Group 1, and require longer lead times to design and develop, however they also provide larger benefits if they have timely implementation. Work to refine the technical requirements and potential solutions for Group 2 projects has progressed since the publication of the ISP. In particular:

- *South Australia to New South Wales interconnector.* This project is well progressed. ElectraNet have completed a consultation on their Project Assessment Draft Report and aim to publish their final RIT-T report in early 2019.
- *Queensland to New South Wales major interconnector upgrade.* TransGrid and Powerlink have commenced the RIT-T process and published the Project Specification Consultation Report in November 2018, considering both minor (group 1) and major (group 2) upgrades.
- *DER integration in South Australia.* A range of projects are underway to support the co-ordinated deployment of DER. These include the Open Energy Networks initiative jointly

undertaken by AEMO and the ENA[FN2], and work to define the minimum technical requirements for the South Australian government's home energy storage initiative.

- *SnowyLink North.* AEMO is working with Snowy Hydro and TransGrid to refine and extend ISP modelling to better understand the costs, benefits and factors that affect the timing of these projects. Detailed design is progressing ahead of a potential RIT-T process. The Snowy Hydro Board's final investment decision for the Snowy 2.0 project is expected later this month. This decision will influence the efficient timing of the SnowyLink North project.

AEMO is also working with Tas Networks to evaluate the potential of advancing the SnowyLink South and Marinus Link between Tasmania and Victoria, which can be used to support renewable resources in Victoria and reliability services following further coal closure in Victoria.

Project Marinus has commenced the initial stages of the RIT-T process. AEMO intends to publish further analysis on the implications of early coal retirement and the impacts of storage in the first half of 2019. All of these projects will also be incorporated into the next ISP, which AEMO hopes to publish in December 2019.

Being further out in time these projects are less certain in their costs and benefits than the Group 1 projects. In many cases they are also more substantive in cost. Nevertheless, early works and cost-benefit analysis for these projects has already commenced and AEMO will continue to monitor progress. Suggestions to streamline the RIT-T, revenue recognition and planning process (as outlined above) should also apply to these projects but as per recommendation 6 will be considered at a later stage following further consultation. Where there is apparent delay the AEMC could use its Last Resort Planning Powers and direct a company to commence its RIT-T process. ***Recommendation 7: If a Group 2 or 3 Project is considered by AEMO and the ESB to be lagging behind its required timing the AEMC should be requested to use its Last Resort Planning Power to direct a company to commence its RIT-T process.***

7. The Next ISP and Beyond

The National Electricity Rules currently require AEMO to produce an annual National Transmission Network Development Plan (NTNDP). The ISP is effectively the next iteration and replacement of the NTNDP. The ISP requires significantly more time to undertake the system analysis and complex modelling required to ensure that the plan is prepared and consulted on in such a way that it can be relied upon by investors and regulators and trusted by stakeholders. As a matter of 'housekeeping' rule changes are required to replace the NTNDP with an ISP delivered at least every two years. ISP updates should be prepared between reports if there is any significant change that must be accommodated in the plan. An ISP update may be warranted if there is a major supply or demand changes, a significant technology change; major change in cost assumptions; or a major change in government policy. The National Electricity Rules should empower AEMO to issue Guidelines on how and when an update to the ISP would be activated and conducted. ***Recommendation 8: Rule changes should be prepared and lodged by AEMO with the AEMC to have the NTNDP replaced by the ISP. These should require the ISP to be developed every 2 years with updates in between plans if there is a defined material event. AEMO should issue guidelines to stakeholders on how and when an update to the ISP would be done.***

The ESB held in-depth facilitated workshops with a broad range of stakeholders over four days in November. These workshops acknowledged the benefits that could flow to consumers from taking a systems approach to transmission planning rather than a more siloed regional approach. NEM wide system planning that co-optimises network, supply-side and demand-side solutions and includes rigorous stakeholder engagement with unbiased consideration of network & non-network solutions would be welcomed.

There was broad consensus that some modifications would be required to future ISPs if the ISP is to have a more central role in identifying and assessing specific transmission projects for investment.

Future ISPs could be improved with some key refinements:

- Enhanced consultation, with greater time for feedback loops and set consultation points throughout the development of the plan including a draft ISP for consultation. It is critical that all stakeholders (for example, consumer groups, generators and demand management participants) can understand and participate in the analysis not just transmission network service providers.
- Increased modelling transparency for more immediate understanding of the foundations of the work.
- A mechanism for agreeing the policies to be included within the ISP and then specific scenarios to test additional policy settings.
- Increased capability for third parties to identify network and non-network solutions to challenges identified in the ISP.
- Revenue adequacy modelling to test the assumptions around generator entry and exit in the short-medium term. The assumption that thermal generators will retire at the end of their technical lives is considered particularly problematic given the revenue stress that many aging coal-fired generators are likely to experience in the short-medium term. Similarly, more flexible plant with better ramping capability may remain in the market longer than expected.
- Price modelling to test the impact on consumers in each region.

The final report for CoGATI provides some details for how these refinements could be made.

Recommendation 9: The ESB will work with AEMC and AEMO to prepare NEL and rule changes to provide to the COAG Energy Council in mid 2019 so that refinements to the inaugural ISP suggested in this paper are included in future ISPs. Once these refinements are made the analysis in the ISP should be adequate for direct use and importation into a RIT-T analysis. In particular where a project or set of credible projects are modelled in the ISP, this analysis should become the first stage of the RIT-T-(ie the Project Specification Consultation Report (PSCR)). This approach would reduce the potential for duplication and therefore the time taken to complete the cost-benefit analysis.

In developing the ISP, there are seven key steps which, if followed, would enable the ISP to replace several of the steps required in the current RIT-T and serve as the first stage in the RIT-T consultation process, the project specification consultation report. To fully realise these efficiencies, early engagement of the AER in the ISP development will also be critical.

1. Scenario Development: AEMO develops scenarios and inputs (including demand forecasts and generation technology costs), based on broad industry consultation and expert input.
2. Identify needs: Governments identify public policy needs, TNSPs identify intra-regional reliability needs, AEMO identifies NEM-wide reliability, security & risk resilience needs.

3. Identify credible options: Working with TNSPs and non-network service providers, identify credible options that address the needs, including non-network options and incremental upgrades to existing plant.
4. Consult on inputs: AEMO consults on the outputs of stages 1-3, including assumptions, methodologies, scenarios, identified needs and initial credible options.
5. Conduct analysis: Using outputs of stages 1-4, AEMO undertakes NEM wide modelling and analysis to determine which combination of the initial credible options most efficiently meets identified needs.
6. Consult on draft results: AEMO publishes draft ISP together with detailed supporting information. Conducts consultation process including customer engagement.
7. Finalise ISP: AEMO updates ISP modelling to reflect outcomes of consultation process, publishes final ISP.

The ESB considers that further work should be undertaken on incorporating these steps into future ISPs. ***Recommendation 10: The ESB should bring back to COAG Energy Council any NEL and NER changes, to enable the actioned ISP to be embedded in the regulatory framework, and the need and set of credible options to meet that need and to take the place of the current Project Specification Consultation Report in the RIT-T for ISP projects.***

TNSPs would remain responsible for identifying the preferred or "best" option with AEMO to confirm that this option remains consistent with the ISP.

As the number of completed ISPs increases with the passage of time, projects should be identified in group three with a subset of these moving to group two and only highly certain projects eventually becoming group one projects. Future ISPs should have a clearer basis for determining whether a project fits within group one, two or three with different implications for the choice of group.

Group one

Projects identified as group one should have a high degree of confidence in the need and net benefits of the credible options to meet that need along with the required timing of the project. As a result, projects identified as group one in future ISPs should be considered to have met the requirements of the current PSCR (as set out above). To better integrate the ISP with transmission investment decisions, following the release of the ISP, group one projects should be fast tracked if they are not already a 'contingent project' for the relevant TNSP with the satisfaction of the cost-benefit assessment the 'trigger' for the AER to undertake a revenue determination for the project. TNSPs should be required to commence the remaining steps of the cost-benefit assessment for any identified group one projects within four months of the release of the ISP.

To the extent that there are time critical early works that could be completed in parallel to the cost-benefit assessment (and that have not already been completed) then government underwriting of these works should be considered.

Group two

Projects identified as group two should have a high degree of confidence in the need and net benefits of the credible options to meet that need but the required timing of the project may still be uncertain.

To support more detailed cost analysis of these projects in subsequent ISPs and to ensure valuable time is not lost on these projects should they be required sooner than expected, government underwriting should be considered for any time critical early works and planning for all identified group two projects.

Group three

The need and timing for projects identified in group three may still be quite uncertain and subject to developments in the market. No additional support is proposed for group three projects.

8. Renewable Energy Zones

After examining a number of factors, the ISP identifies 34 Renewable Energy Zones. The principal reasons for the choice of these sites was the availability of good resources and their least cost integration into the transmission system. The ISP addresses the following attributes:

- *Resource quality and diversity.* High diversity (low correlation) of renewables within a REZ and across the NEM is valuable because it allows more consistent generation and hence less storage. Grid scale solar power is not as diverse as wind resources across the NEM. Wind resources in Queensland provide high diversity with other areas; and Tasmanian wind is somewhat diverse with the mainland. It is also expected that off shore wind resources will have different capacity capabilities than terrestrial wind.
- *Diversity and demand matching:* Integrating large amounts of highly correlated renewable generation is more difficult for system stability than non-correlated supplies. In assessing the REZ's the optimization favoured a REZ resource that best matched its load.
- *Transmission development to access a REZ;* Currently transmission access is open access meaning a participant is able to negotiate connection to any part of the network so long as required technical standards are met. This access arrangement can cause (and is causing) congestion challenges. Once a development exceeds existing network capacity generators will be restricted in their operations by limited network capacity and also by lower system strength or changing losses. Again, this emphasizes the importance of coordinated development rather than incremental unplanned activity.
- *System strength:* The ISP shows that in the 2020's system strength will require some remediation for the connections that are expected in some localities. From the 2030's system strength remediation will be needed for most renewable connections. This of course makes it even more clear that a coordinated approach is essential. The economics of renewable generators contributing to system strength for a REZ area rather than for individual wind and solar farms alone is a more favourable outcome for customers.
- *Network losses:* The more distant generation is from the load the higher the transport losses in an AC system. In the NEM such losses are represented through Marginal Loss Factors (MLFs). There are a large number of factors that effect MLFs but for a generator the prices they receive are related to their losses and as losses increase generator returns fall. This has become a matter of considerable concern for developers who experience loss factors they were not expecting. In the ISP the transmission system losses have been considered and each REZ was examined for its MLF sensitivity.

Following these assessments several immediately optimal REZ development areas were included in the ISP:

- NSW: Central Tablelands (wind and solar) and Southern tablelands (wind)
- Queensland: Darling Downs and Fitzroy (wind and solar)
- SA: Northern (solar) and Mid-North (wind)
- Tasmania: North West (wind)

- Victoria : Mayne (wind).

Additional connections of renewable projects beyond the current transmission capacity were identified in conjunction with the Group 2 developments identified earlier. These optimal areas for development include:

- NSW: New England (wind and solar), North West (wind and solar), Northern tablelands (wind and solar) and Murray River (solar)
- SA: Riverland (wind and solar)
- Victoria: Western (wind) and Murray River (solar).

The Murray River and Western Victoria REZ's are already experiencing committed renewable developments and large amounts of additional generation is expected in the near term. RIT-T tests are underway to assess the transmission development required to support these REZ's and to reduce the costs of congestion, provided this will create a net market benefit for consumers.

At the present time the transmission grid and renewable energy generation are facing a number of issues. AEMO and the transmission companies are receiving unprecedented volumes of connection enquiries and the main concerns are connection, congestion and access. These issues need further consideration as they are complex, interrelated and their implications for pricing and market design go well beyond specific REZ issues.

Access for a new generator is via a connection to the shared network. The generator funds infrastructure to the connect into the network and beyond that point the consumer funds the shared network. Where there are many different generators in a similar area (like a REZ) connecting to the network via a shared connection asset is the most efficient approach and also likely to be more favoured by local communities. There is potential for shared connection assets, but the Scale Efficient Network extension approach has been ineffective due to competition between generators, disparate timing of development and restrictive confidentiality requirements on the transmission companies currently contained in the rules. One approach that would encourage investment in REZs and also encourage shared connection assets is for an Adjustment Fund referred to earlier to fund the asset initially. Under this approach the Fund would finance a large capacity connection and then sell down the capacity to generators as they develop. Over time the funds would be fully recovered.

Recommendation 11: That the ESB examine the possibility of a Fund to extend transmission assets to connect to Renewable Energy Zones with the cost of this transmission progressively recovered from consumers if and when utilisation increases. The required size of the finance, the source of funds, and how funds should be recovered and managed should be part of the examination.

Congestion risk is a major impediment to investment and the issue is whether the current open access regime provides investment certainty to generator developers and lead to efficient congestion management in the long term. There is an ongoing and related concern about marginal loss factors. These affect a generator's revenue stream and hence commerciality. One key issue is that marginal loss factors are set annually. . There is significant year on year fluctuations due to the large number of generators connecting into the system; as well as marginal loss factors being challenging to calculate given the large number of generators.

The AEMC, in its final CoGATI report set out a path forward on addressing the above issues, and resolving concerns about access and congestion that need to be considered in 2019 by the ESB.

Recommendation 12: The ESB recommends that as part of their work they report back to the COAG Energy Council in 2019 on the detailed requirements needed to reform connections, access and congestion arrangements going forward.- and options for addressing them.