2020 ISP Appendix 9. ISP methodology

30 July 2020

Important notice

PURPOSE

This is Appendix 9 to the Final 2020 Integrated System Plan, available at https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp.

DISCLAIMER

VERSION CONTROL

Version	Release date	Changes
1.0	30/7/2020	Initial release

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2020 ISP Appendices

A9.1. Introduction

This ISP Methodology appendix provides an overview of the engineering assessment applied to develop the 2020 ISP. It supplements the market modelling methodology document published on AEMO's website[1].

This appendix includes summaries of transmission option development and assessment, the power system analysis methodology, and interactions with both the capacity outlook modelling and time sequential modelling.

The appendix is set out in the following sections:

- Section A9.2 provides an overview of the ISP methodology.
- Section A9.3 introduces and lists links to critical modelling inputs and assumptions used to deliver the ISP.
- Section A9.4 discusses the engineering assessment process in which transmission expansion options are developed, verified and selected.
- Section A9.5 describes the published ISP modelling outputs.

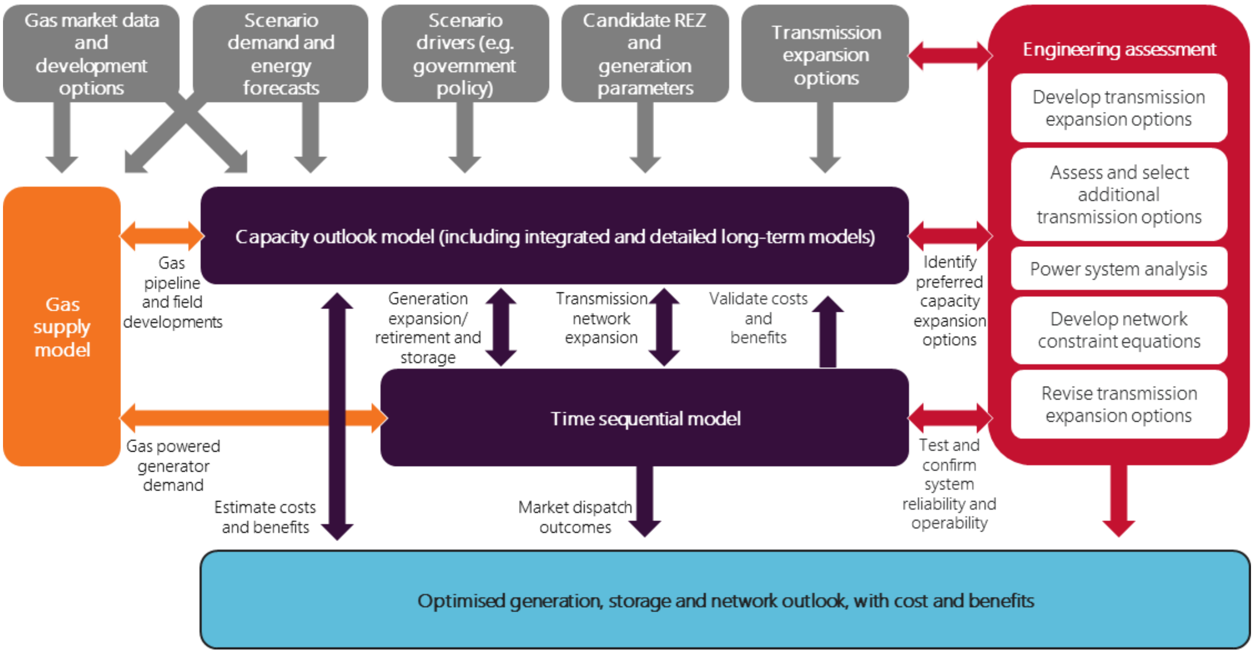
[1] At https://www.aemo.com.au/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

A9.2. Overview of ISP methodology

The ISP is prepared by performing an iterative process involving both integrated energy market modelling and power system analysis. The ISP aims to maximise the economic benefit for all those who produce, consume or transport electricity in the market by deriving the optimised generation, storage and network outlook.

Figure 1 illustrates the process at a high level, showing how the analysis leads to the development of the optimised generation, storage and network outlook.

Figure 1 Overview of Integrated System Plan methodology



This document provides a high-level description of the iterative process of market modelling and power system analysis. It supplements the market modelling methodology report, and provides more detailed information on the engineering assessments conducted for the ISP.

More detail on the various methodologies that enable the forecasting of consumer consumption and demand, as well as the methodologies for modelling the market developments required to efficiently meet that consumer demand, are available on AEMO's website[2].

[2] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

A9.3. Inputs

AEMO has undertaken extensive consultation to ensure its planning and forecasting publications are the highest possible quality, with data that is fit for purpose and industry reviewed. Furthermore, by following the AER's Forecasting Best Practice Guidelines[3], AEMO ensures that its forecasting is transparent, follows well understood methodologies, provides an opportunity for industry engagement and review, and ultimately provides timely and accurate decision-making support to the industry.

This section notes that the methodology for modelling the future power system relies on a considerable volume of inputs spanning the energy sector. These inputs and assumptions, as well as the scenarios to apply for the ISP, are published within the Inputs, Assumptions and Scenarios Report and accompanying Inputs and Assumptions Workbook.

Table 1 provides references for the ISP inputs and assumptions documentation.

AEMO reviews the forecasting and planning scenarios, inputs and assumptions annually, and this provides AEMO an opportunity to assess whether there have been any material changes in inputs warranting an ISP update. During the development of the ISP, the Draft ISP is also published to enable consultation on key outputs. The Final ISP is accompanied by a Consultation Summary Report[4], which provides further detail on the engagement on the Draft ISP Consultation.

Table 1 Documentation on ISP inputs and assumptions

Document	Source
Forecasting and planning scenarios, inputs and assumptions	https://aemo.com.au/-/media/files/electricity/nem/planning_and_forecasting/inputs-assumptions-methodologies/2019/2019-20-forecasting-and-planning-scenarios-inputs-and-assumptions-report.pdf
2020 input and assumptions workbook	https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp

[3] AER. *Guidelines to make the Integrated System Plan actionable (including Forecasting Best Practice Guidelines)*, at https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/guidelines-to-make-the-integrated-system-plan-actionable.

[4] At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp.

A9.4. Engineering assessment

This section explains the engineering assessments applied in the ISP. As shown in Figure 1, the ISP methodology is iterative – technical information is used to inform the market modelling, and the market modelling results are investigated through power system analysis to ensure that the reliability and system security needs of the power system will be met. The engineering assessment has four main components:

- Development of transmission options (A9.4.2).
- Assessment and selection of candidate options (A9.4.3).
- Power system analysis (A9.4.4).
- Consideration of the cost of transmission (A9.4.5).

This section provides an overview of the iteration between engineering assessment and market modelling, before stepping through each of the engineering assessment components in detail.

A9.4.1 Iteration of engineering assessment and market modelling

Engineering network analysis is used to develop transmission options (Section A9.4.2) that are input into the capacity outlook model which is detailed AEMO's Market modelling methodology paper[5]. The outputs of this model are refined through power system studies using the PSS®E platform (Section A9.4.4). The generation, storage and transmission expansion options identified in the engineering analysis and by the capacity outlook model are assessed, and the most technically viable and economical transmission options are selected (explained in Section A9.4.3). If these preferred options differ from the inputs provided to the model, the inputs into the model are modified and the process is executed again until the outputs are aligned.

The inputs into the time sequential model are provided following a series of power system analyses where thermal and stability constraint equations (detailed in Section A9.4.4.1) result in optimal generator dispatch outcomes. Power system analysis studies are conducted to confirm whether the transmission options identified are adequate for the predicted generation dispatch over the ISP horizon or whether additional transmission options should be developed to avoid network violations and unserved energy, discussed in Section A9.4.4.3. In the event network changes are required at this stage in the process, the inputs into the time sequential model are adjusted and the process is repeated. The time sequential model is explained in AEMO's Market modelling methodology paper[6]. In some cases, adjustments will be needed to inform the overarching generation, storage and transmission expansion model. Iterations continue until the optimised generation, storage and network outlook have met the system reliability and operability needs and the overall costs and benefits have been determined.

Throughout the engineering assessment process, the cost effectiveness of transmission options is considered, (discussed briefly in Section A9.4.5) to ensure economic benefit is achieved.

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[5] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

[6] At https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

A9.4.2 Development of transmission options

Credible options to increase transfer capacity between regions as well as between REZs and load centres are ultimately aimed at maximising the economic benefit for all those who produce, consume or transport electricity in the market.

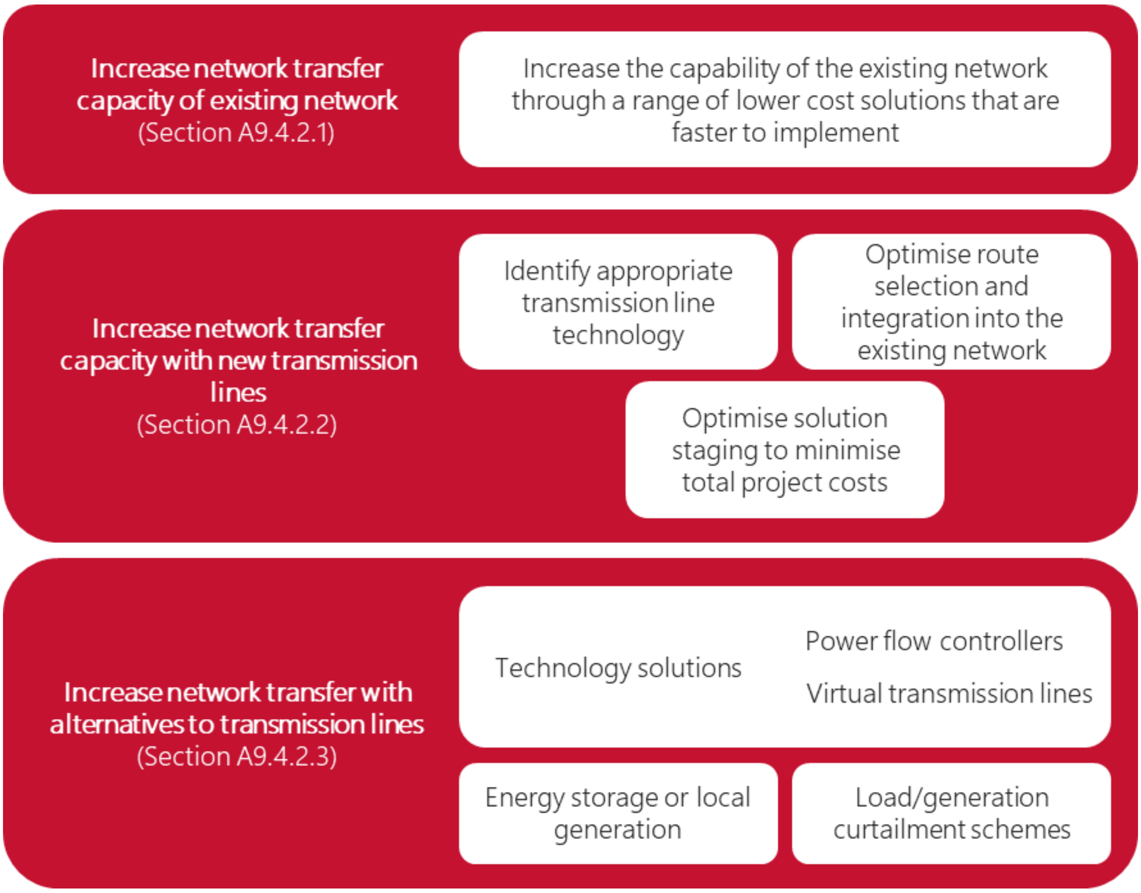
Many parameters are considered when developing options. A technical assessment of these parameters is used to prepare the transmission options and their associated costs and capacity gains, which is provided as an input to the capacity outlook model.

Figure 2 summarises the parameters considered in developing each type of transmission option and points to where more details can be found in this section. The following options to increase transmission capacity are considered:

- Minor network upgrades and augmentations to the existing network (brown field augmentation).
- Additional new transmission lines (green field augmentation).
- Alternative technologies to minimise the requirement for new transmission lines, including non-network options.

When considering whether to upgrade existing network or build new transmission, AEMO also assesses alternative technology options to increase the transfer capacity of the existing network, including power flow controllers and non-network options. Once the credible transmission options have been identified, detailed power flow studies will be completed to confirm the capability of the network or non-network augmentation.

Figure 2 Developing credible transmission options to increase network transfer capacity in the ISP



A9.4.2.1 Options to increase transfer capacity of existing network

Maximising the economic benefit for all those who produce, consume or transport electricity in the market can be achieved through minor network upgrades and augmentations to the existing network. These upgrades can be lower cost and have a short lead time to implementation, with less environmental and community impact. They usually meet the needs for small capacity gains on the network.

The options considered to increase capability of the existing transmission network are:

- Network reconfiguration to balance or reduce overloaded network elements.
- Application of real-time ratings for transmission lines for additional thermal capacity under favourable weather conditions.
- Control schemes to reduce generation and load immediately following a contingency.
- Uprating of transmission lines for additional thermal capacity.
- Additional new transformers for additional thermal capacity.
- Additional new static and/or dynamic reactive plant.

Once the existing network transmission minor augmentations have been identified, power system analysis is conducted to determine the appropriateness of each option to fulfil the identified need.

A9.4.2.2 Options for additional new transmission lines

The configuration of new transmission lines to increase network capacity is assessed based on:

- Identification of appropriate transmission line technology with technical feasibility.
- Optimisation of route selection and integration into the existing network, including cost effective access to renewable generation and consideration of energy losses.
- Optimisation of solution staging to minimise total project costs.

The sections below discuss each of these considerations. This paper does not describe in detail the supporting work required to connect a new transmission line into the existing network, for example transformer and switchbay sizing and design.

Identify appropriate transmission line technology

Two types of transmission technology are currently in use to transfer electricity in the power system, which are both considered when identifying new transmission line options. These technologies are:

- High voltage alternating current (HVAC) transmission.
- High voltage direct current (HVDC) transmission.

The benefits of each technology are assessed and verified through a technical feasibility to determine the most appropriate technology to use, to design a new transmission line or network augmentation.

HVAC transmission

Most of the existing extra high voltage transmission network in the NEM is HVAC and is designed to operate at nominal voltages of 220 kV, 275 kV, 330 kV or 500 kV. The following factors are considered in the selection of new transmission augmentation options:

- Operating voltage level of existing transmission network and options to integrate the new transmission lines within the existing electricity network.
- Transfer capacity – higher voltages accommodate higher transfer capacity.
- Network losses – higher voltages result in lower network losses.

The capacity of the network augmentation is designed and refined through power system analysis.

The added benefit of HVAC is its ability to collect additional generation along the route of the transmission line as well as the relatively lower cost of the augmentations for shorter distances.

HVDC transmission

The NEM currently has two types of HVDC technology transmission augmentations installed which are considered in the selection of new transmission augmentation options:

- HVDC line commutated converter technology (LCC-HVDC).
- HVDC voltage source converter technology (VSC-HVDC).

LCC-HVDC technology is used on Basslink (the interconnector between Victoria and Tasmania) and is typically used to transfer large amounts of power. However, LCC-HVDC technology requires adequate fault level to operate correctly, making it unsuitable to connect to weaker systems. VSC-HVDC technology, as used on Murraylink and Terranora (Victoria to South Australia and New South Wales to Queensland interconnectors respectively) can operate in weaker AC systems and has greater operational flexibility.

HVDC solutions are more competitive with HVAC applications over long distances, typically several hundred kilometres, or for applications under ground and under water. The cost of HVDC technology for shorter transmission lines is expensive because of the high cost of converter stations at each end of the transmission line. HVDC technology over a long distance has the added benefit of significantly reduced transmission losses and increased power system stability when compared to the HVAC equivalent. As the converter station is the key driver of costs, the collection of generation sources along the path of an HVDC transmission line, by building additional converter stations, often results in HVAC out-competing HVDC on cost.

For the ISP, HVDC-VSC technology with a DC voltage range of ±320 kV to ±500 kV is considered.

Optimise route selection and integration into the existing network

Several factors are considered when developing a path for new transmission lines, and considering how best to integrate new lines into the existing network. For high-level planning studies, these include route diversity to existing transmission lines, proximity to REZs and therefore facilitation of the connection of new generation, transmission technology limitations, and costs. The aim of each of these parameters, when designing a new transmission line, is to optimise the route to maximise economic benefit and network transfer capacity, while ensuring all necessary technical, environmental and cultural challenges are considered.

Route diversity

Transmission lines should be designed to optimise transfer reliability. The route selection is enhanced by considering the diversity of the path chosen to existing transmission lines or within the transmission network configuration. Some transmission line sections may run through areas that are associated with low probability risks that could have a high impact on the reliability of the transmission scheme. For example, if a line runs through an area that is prone to bushfires, then two lines using the same route would give a less reliable outcome than lines operating on diverse routes. In particular, route diversity from the existing interconnectors would harden the grid against extreme climate conditions.

Facilitating the connection of new generation (proximity to REZs)

There may be overall economic benefit in selecting a transmission path that runs through areas that have potential for future generation development (or demand development). For example, given that 35 candidate REZs are identified across the NEM in the ISP, an interconnector path through REZs would open up connection of renewable generation and storage in these REZs – this results in transmission options that provide multiple benefits.

Transmission technology limitations

Existing network and technology limitations, such as those listed below, must be considered in the route selection for a transmission line:

- **Space for transmission equipment** – physical space limitations in substations or easements can dictate the only available network connection or routes available for a new transmission line or network augmentation.
- **Spare network capacity** – network capacity limitations can dictate the available transmission network capacity that a new transmission line can connect.
- **Network losses** – the advantages of selecting a route that picks up generation along the way, or increases reliability as a result of diversification, can have an adverse effect on energy losses on the network. Power system analysis is used to confirm whether losses for a particular transmission line route are within acceptable bounds.

Urban and ecologically or culturally sensitive areas

A high-level assessment of impact on environmentally and culturally sensitive areas is undertaken when developing transmission path options. These important matters are considered in detail as options are progressed through the regulatory and design phases.

Optimise solution staging to minimise total project costs

The aim of new transmission lines providing economic benefit to the NEM is largely met through minimising transmission network costs. This can be achieved through effective transmission development staging. If REZ generation grows in stages or inter-regional transfer capacity increases are required in stages, it may be economical to stage the transmission capacity to match the staging of generation or import/export levels.

Staging transmission development can realise cost benefits if there are several years between the growth of generation or interconnector stages, or if there is uncertainty regarding the ultimate development of the remote generation. In other instances, where the steps of generation growth are quite close to one another (for example, one or two years), it may be more economical to build the entire transmission option at once. This complete build could benefit from economies of scale with engineering, procurement and construction activities.

HVAC transmission schemes can be staged by:

- Constructing the line for operation at high voltage (such as 500 kV) but initially operating at a lower voltage (such as 330 kV) to match the voltage of the connection point in the shared network. This allows the cost of the 500/330 kV transformers to be deferred. Ultimate operation at 500 kV will provide lower losses and higher transmission capacity, but any connection access provided at the lower transmission voltage initially would need to be converted to connect at the higher transmission voltage afterwards.
- Initially stringing a double-circuit line with only one strung circuit can lower the initial capital cost by about 25%. The overall line capacity can be doubled by later stringing the second circuit at a deferred cost.

HVDC transmission schemes can be staged by:

- Constructing an HVDC bipole line but initially operating as a monopole to allow the cost of the second stage converters to be deferred. Initial losses can be halved by paralleling the conductors. Alternatively, the second pole can be deferred.
- Converters can be added in either parallel or series with the original converters allowing either current or voltage upgrades. The design of the transmission line will need to allow for these upgrades.

A9.4.2.3 Alternatives to transmission lines

Alternative technologies and non-network solutions are also considered in order to assess the most efficient approach to meet the identified need. Alternative technologies and non-network options can fulfil the need to increase power system capacity while still maximising economic benefit to all those who produce, consume and transport electricity in the market. Delivery of these alternative technologies and non-network options is often a case-by-case regulatory treatment depending on the nature of the identified need and the alternative option selected.

Alternatives to transmission can include:

- Technology solutions such as power flow controllers and virtual transmission lines.
- Energy storage or local generation.
- Control schemes such as fast acting load curtailment schemes, or local generation run-back and curtailment schemes.

The approach to assessing these options is not all that different from the assessments needed for transmission options. AEMO conducts a technical analysis to determine the system limits with the option in service. This is followed by an economic analysis to determine the net market benefits.

An accurate assessment of alternative technologies may require information which is only available in the late stages of project completion and is often commercially sensitive. AEMO receives non-network submissions as part of the ISP consultation process, in order to facilitate this assessment. AEMO's approach is to assess the technical capability of options with the available information and undertake economic analysis to consider each submission as an alternative to network options.

The sections below discuss each of these alternatives.

Power flow controllers

Power flow on individual HVAC transmission lines is usually not directly controlled. When power flows from one point to another along parallel flow paths, the amount of power on an individual line is a function of its fixed impedance. This can lead to the power being unevenly shared between the lines. Inter-regional transfer capability can thus be limited because one line on the flow path is at its limit while another is under-utilised.

To increase transfer capability, power flow controllers are applied to shift power from an over-utilised line to under-utilised lines. Two different power flow controller technologies are considered in the development of transmission options for the ISP, described in the following sections.

Phase shifting transformer

Phase shifting transformers are a mature technology normally connected in series with a transmission line. They create a phase shift in the voltage angle between the primary and secondary side of the transformer. Power flow is proportional to the sine of the voltage angle difference across the transformer. Power flow can thus be balanced between a transmission corridor with phase shifting transformers and one without any.

Modular power flow controller

A modular power flow controller is a power electronics-based device that is installed in series with a transmission line. It controls power flow along the line by modifying the apparent series impedance of the line and injecting a series sinusoidal voltage waveform in quadrature to the line current. Adjusting the magnitude of the voltage injection allows the impedance to be controlled and to operate in either an inductive or capacitive mode. In the inductive mode, power flow through a transmission line is reduced and in the capacitive mode power flow through a transmission line is increased.

Series capacitor

Series capacitors are typically used on long transmission lines where increased power flow, increased system stability or power oscillation damping is required. Series capacitors reduce the reactance of a transmission line, which allows higher active power transfer through the line. In addition, on long lines a series capacitor can partly compensate the voltage drop caused by the reactance of the long transmission line. Series capacitors also improve load sharing between parallel lines. There are two main types of series compensation – fixed series capacitors, and thyristor-controlled series capacitors which can provide smoother control of power flow.

Virtual transmission lines

The virtual transmission line concept assumes the use of storage (or fast acting power response) at both ends of a particular transmission line which is expected to constrain power transfer. Immediately following a contingency event, the storage at the sending end of the transmission line absorbs power and the storage at the receiving end releases the same amount of power (less the transmission line losses). This avoids any thermal overloading on surrounding parallel transmission lines. This process of placing energy storage on a transmission line and operating it to inject or absorb real power, mimicking transmission line flows, is an alternative to uprating, replacing or building new transmission lines to increase transmission capacity.

A similar concept can be applied to increase the transient or voltage stability limits of a transmission line. Following a fault on a line or the trip of a generator, the sending end storage can absorb power and the receiving end storage can release the power to the network, thus increasing the pre-contingency transfer levels.

Instead of storage, a fast-acting braking resistor can be used at one end of the transmission line (with storage at the other end) if increased network capability is only needed in one direction.

Energy storage or local generation

Local generation near load centres can reduce transmission network loading and therefore avoid or defer transmission augmentation. If generators are not online, a contractual arrangement can allow for providing services like reactive power, system strength or inertia. This is a non-network option and can assist in increasing transmission capability.

Alternatively, energy storage can store energy at times of excess generation in the grid and release at the time of generation shortage to meet demand. There are two leading types of energy storage currently implemented in the NEM – battery energy storage systems (BESS) and pumped hydro energy storage (PHES).

Location of PHES is site-specific, as the hydro resources need to be available to build the energy storage facility. BESS, on the other hand, can be located almost anywhere in the system (subject to availability of land and environmental approvals).

A targeted use of storage may be justified in specific cases, such as firming within REZs for supporting variable renewable energy, or as part of the transmission solution to reduce the costs in development of transmission, or by facilitating staging of a network augmentation.

Load curtailment schemes

Load curtailment is where the consumer agrees to reduce usage. The transmission network can experience high loading during times of high demand on hot summer afternoons or cold winter days. Rapid load reduction following contingencies can reduce the need for transmission augmentation.

Local generation run-back or curtailment schemes

Run-back schemes and other control schemes can rapidly reduce/disconnect generation following a contingency to manage system security, and avoid the need otherwise for network augmentation. These are used widely in the NEM.

A9.4.3 Assessment and selection of candidate options

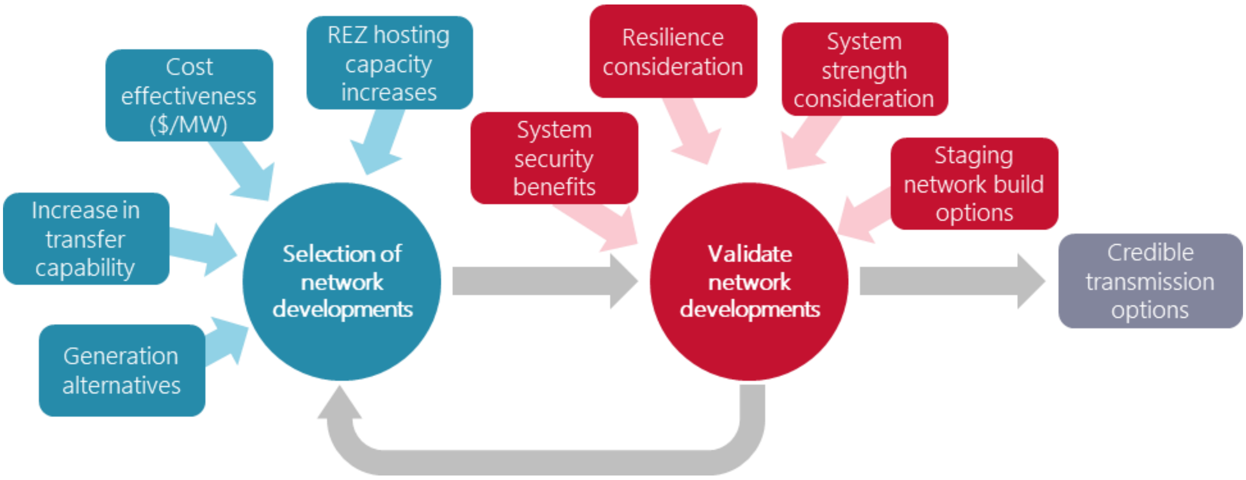
As Section A9.4.2 noted, credible alternative candidate transmission options are identified to increase the transfer capacity between regions, and between REZs and load centres. This section describes the process taken to assess and select candidate options and provides an example for how two different options are compared. As discussed in Section ·, the ultimate consideration of options includes consideration of alternative technologies and non-network options.

In order to prepare credible alternative candidate transmission options AEMO considers the augmentations identified in each TNSP's Transmission Annual Planning Report and via the RIT-T. In addition to information available from TNSPs, transfer capability and indicative cost estimates of network options are determined as described in Section A9.4.4 and Section A9.4.5 respectively. AEMO consults with TNSPs to finalise alternative credible transmission options.

Once the candidate options have been developed, these are considered in the capacity outlook model described in AEMO's Market modelling methodology paper[7]. For network augmentations, there are a number of key factors which influence the decision on which option is selected based on the objectives of the capacity outlook model. In addition, the capacity outlook model does not presently include some power system considerations when making transmission and generation decisions.

As such, AEMO employs a two-stage process at this point of the modelling to capture these factors, illustrated in Figure 3. The figure is followed by a description of the decision factors applied in each of the stages, and an example application of the process.

Figure 3 Two stage process of credible transmission option assessment and selection



Decision factors for selecting credible transmission options for capacity modelling

The first step in this process, which aims to select the network development, considers the decision factors listed in Table 2.

Table 2 Decision factors for determining credible options for capacity modelling

Decision factor	Consideration in selecting credible network development option
Total increase in transfer capability	Match the option to the size of the capacity needed.
Cost effectiveness of increasing transfer capability ($/MW)	Compare cost effectiveness of option to other network, storage and generation options.
Additional REZ hosting capacity	Determine additional REZ hosting capacity provided by the inter or intra-regional augmentations.
Generation and storage alternatives	Determine whether an equivalent service could be provided by a generator or through storage rather than a network solution.

[7] Available via https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

Decision factors when validating the network development options

The second step in the process, which aims to select the credible network development options, considers the decision factors listed in Table 3.

Table 3 Decision factors when validating the network development plan

Decision factor	Consideration in validating credible network development option
Resilience considerations	Assess route diversity, general route path, capability during outages, etc.
System strength benefits	Conduct initial assessment of the system strength benefits between competing network options.
System security	Determine whether there is any material influence from additional system security, for example additional interconnection to a region which reduces the likelihood of islanding conditions.
Staging network builds	As an enhancement, staging or sharing of network augmentations is considered.
Confirmation of model performance	As the capacity expansion model needs to approximate power system characteristics, the accuracy of these approximations is validated.

Example application of the assessment and selection process

Table 4 provides an example of the two-stage process of shortlisting credible options to test in the capacity outlook model – an HVDC option considered alongside a HVAC option for an interconnector between Victoria and New South Wales. In this example, the HVAC option is preferred because of its lower cost compared to the HVDC option, and its ability to efficiently connect more renewable generation along the route.

Table 4 Shortlisting considerations between two credible options for an interconnector between Victoria and New South Wales

Technology	HVDC	HVAC
Option	VNI option 11 2,000 MW bi-pole HVDC connection between North of Melbourne and Wagga Wagga via Shepparton area with an additional converter station in between to connect renewable generation.	VNI option 6 (one of the preferred options) A 500 kV double circuit line between a new substation north of Ballarat and Wagga Wagga via Shepparton with a new terminal station in between to connect renewable generation.
Additional transfer Capacity	VIC to NSW: 1,750 MW[A] NSW to VIC: 1,750 MW	VIC to NSW: 1,930 MW NSW to VIC: 1,800 MW
Cost estimate ($ million)	2,680	1,730
$/MW	$1.53 million/MW	$0.90 million/MW
REZ hosting capacity	Central North Vic: (V6) +2,000 MW	Western Victoria (V3): +1,000 MW Central North Vic: (V6) +2,000 MW

A. Transfer limit of 1,750 MW is determined with each of the HVDC pole transfer 875 MW. For an outage of pole, transfer in the remaining pole increases by 125 MW and remaining 750 MW flows through the parallel AC network.

A9.4.4 Power system analysis

Power system analysis is carried out to ensure that, for whichever transmission option is selected, transmission elements are not overloaded, and system security is maintained. This involves determination of transfer capability of the existing transmission network and then considering the ability of possible network and non-network options to increase transfer capability.

Transfer capability is subject to network constraints, which can be caused by thermal capacity limitations of transmission assets, as well as voltage, transient and oscillatory stability limits of the system. Secure operation of the power system also depends on safe levels of Rate of Change of Frequency (RoCoF) and system strength. Power system analysis includes:

- Review and determination of network limitations, including thermal capability as well as voltage, transient and oscillatory stability limits (A9.4.4.1).
- Development of thermal, stability, RoCoF and system strength constraint equations, which are applied in the half hourly market simulations (A9.4.4.2).
- Identification of a need for transmission development (A9.4.4.3).
- Consideration of marginal loss factors (A9.4.4.4).
- Assessment of system strength levels (A9.4.4.5).
- Assessment of power system inertia levels (A9.4.4.6).

The following sections consider each of these power system analysis components.

A9.4.4.1 Network limitations

Thermal capability

The power flow through a transmission element is limited to its maximum thermal capacity. TNSPs provide transmission line and transformer ratings for different ambient temperatures, seasons, months, and times of day. The following thermal ratings are applied in the network capability assessment:

- Normal ratings for pre-contingent conditions.
- Contingency ratings for post-contingent conditions.
- Short-term ratings for post contingency conditions, if an operational solution is available to bring the line loading below the normal rating within the allowed time.

The determination of maximum transfer levels is carried out using PSS®E studies.

Voltage stability

Voltage stability refers to maintaining stable voltage control following the most severe credible contingency event or any protected event. Assessment of voltage stability limit is undertaken as per requirements in Chapter 5 of the NER. The determination of voltage stability limits is carried out using PSS®E studies.

Transient stability

Transient stability refers to maintaining the power system in synchronism and remaining stable following any credible contingency event or protected event. Assessment of transient stability limits is undertaken as per requirements in Chapter 5 of the NER. The determination of transient stability limits is carried out using PSS®E studies.

Oscillatory stability

Oscillatory stability refers to maintaining the power system in synchronism and remaining stable in the absence of any contingency event, for any level of inter-regional or intra-regional power transfer up to the applicable operational limit; or following any credible contingency event or protected event. Assessment of oscillatory stability limit is undertaken as per requirements in Chapter 5 of the NER. The determination of oscillatory stability limits is carried out using PSS®E and Mudpack studies.

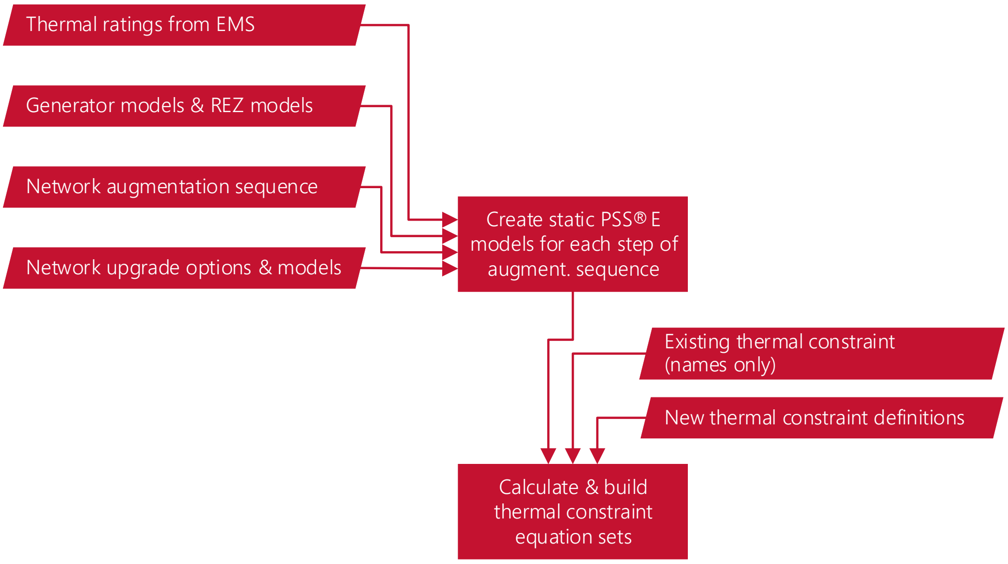
A9.4.4.2 Constraint equations

Depending on consumer demand, dispatch of generation and availability of network and non-network assets, transmission elements can become congested. To manage network flows AEMO utilises constraint equations in the NEM dispatch engine (NEMDE), which runs every five minutes. A constraint equation is used to determine the optimal dispatch of generators based on their offers (or bids) to manage flows on specific transmission lines (and other equipment) for each dispatch interval. A similar approach is applied to investigate network constraints in a time sequential market simulation of load and generation dispatch over the planning period of the ISP. There are two specific sets of constraint equations considered in the determination of optimal market dispatch outcomes from the time sequential model: thermal constraint equations and stability constraint equations. These are discussed in more detail in the following sections.

Thermal constraint equations

Thermal constraint equations are built from PSS®E load flow cases for a given network configuration. Thermal ratings of the transmission network are applied as per the latest information in the Input and Assumptions Workbook. The process of developing thermal constraint equations is illustrated in Figure 4.

Figure 4 Thermal constraint equation process



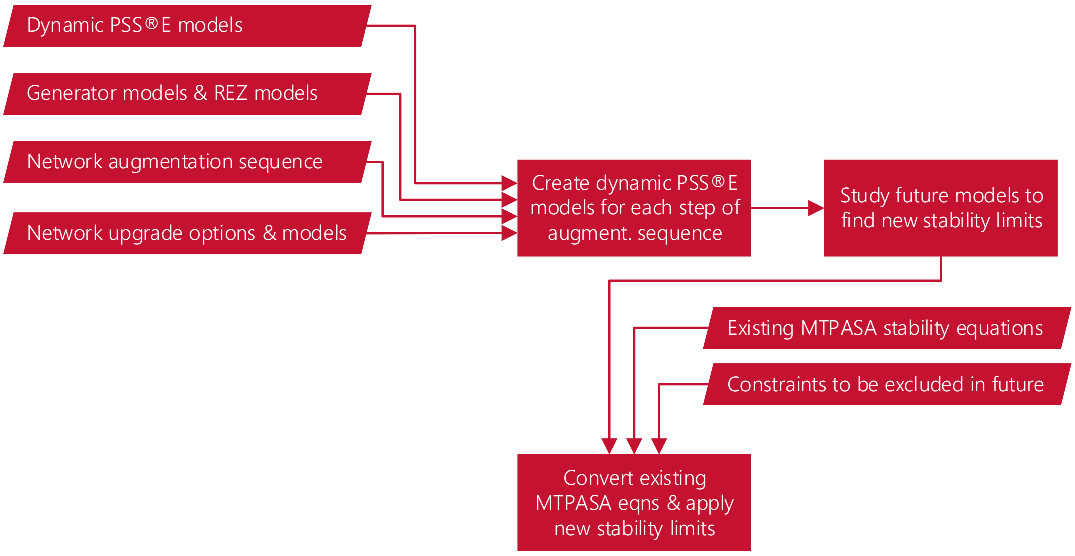
Note: EMS – Energy Management System

Stability constraint equations

Stability constraint equations for the existing network are developed and validated by the relevant TNSP. AEMO conducts due diligence on these constraints before applying them in dispatch. Development of these stability constraint equations is time-consuming. For modelling the existing network, dispatch stability constraint equations are converted into a different format for the half-hourly simulations. These stability equations include transfer levels determined by voltage, transient, oscillatory RoCoF and system strength limits.

For the future network, dynamic network models are created with future upgrades and then studied to determine the difference in stability limits from the existing network. For some upgrades, the TNSPs have already completed these studies, so their result is used wherever possible. From these studies an offset to the right-hand-side of the existing Pre-Dispatch, Short-Term or Medium-Term Projected Assessment of System Adequacy (PDPASA, STPASA or MTPASA) constraint equation is determined and applied in the stability constraint equations. This process is detailed in Figure 5.

Figure 5 Stability constraint equation process



Note: MTPASA – Medium term projected assessment of system adequacy

A9.4.4.3 Identifying a need for transmission development

The capacity outlook model identifies optimal capacity size and service dates of new generation, storage and transmission, and generation retirements required to meet customer demand under the modelled scenario while factoring various policy, technical or financial constraints. Power system studies and investigations carried out earlier are applied to identify additional intra-regional augmentation to connect generation to the load centres. These intra-regional augmentations and their timing are tested through time sequential (typical 30-minute interval) simulations.

The time sequential model provides information such as generation dispatch, operation of network constraints and frequency of binding constraints. Generation dispatch at selected intervals is downloaded to PSS®E load flow cases and power system analysis is carried out to investigate the performance of the network. Results obtained from time sequential simulation, constraint statistics and power flow analyses are investigated to revalidate network augmentation and to identify any additional network augmentation to ensure system security and reliability.

Power system studies are carried out for the following analyses:

- Verification of the network design under regional maximum demand conditions.
- Verification of the network design under regional maximum variable renewable energy generation conditions.
- Verification of an augmentation under selected conditions of interest, for example high interconnector flow plus inclusion of REZ generation.
- Analysis of the performance of a constraint equation.

A9.4.4.4 Marginal loss factors

Energy is lost as it travels through the transmission network, and these losses increase as more generation connects in locations that are distant from load centres. In the NEM, marginal loss factors (MLFs) are applied to market settlements, adjusting payments to reflect the impact of incremental energy transfer losses. MLFs are used to adjust the price of electricity in a NEM region, relative to the regional reference node[8], in a calculation that aims to recognise the difference between a generator's output and the energy that is actually

[8] The reference point (or designated reference node) for setting a region's wholesale electricity price.

delivered to consumers. In dispatch and settlement in the NEM, the local price of electricity at a connection point is equal to the regional price multiplied by the MLF.

In the interest of maximising the economic benefit for all those who produce, consume or transport electricity in the market, MLF calculations are an important consideration for investors in new generation and storage. Higher MLFs tend to advantage, and lower MLFs tend to disadvantage, generation connection points.

Power system analysis studies are executed to establish the way in which MLFs change across the NEM considering the following factors:

- Transmission and distribution network – if new generation is added at an electrically distant connection point, the MLF decreases more than if it had been added to a connection point near the high-voltage network.
- Generation profile in the area – if new generation is only running at the same times other nearby generators are also running, the MLF decreases further. For example, solar generators in an area all produce power at the same time, so adding more of this type of generator will decrease the MLF more than if a different generator technology was added.
- Load profile in the area – if new generation mainly produces power at times when there is light load in the area, the decrease in MLF will be greater.
- Intra-regional and inter-regional flows – wider trends affecting MLFs include decreasing consumption, increasing distributed generation, changing industrial loads, and retiring generators.

In addition to new generator connections, a number of other events can cause large changes in power flow across the transmission network, and corresponding large changes in MLF. These include:

- Retirement of generation.
- Change in fuel mix.
- Changes in electrical load.

The projected increase in development of renewable generation across the NEM will result in changes to network flow patterns, the network itself where augmentations or new interconnection is undertaken, to network losses as different parts of the network are utilised in different ways. As a result, MLFs will change.

MLF robustness calculation

The MLF robustness is the sensitivity of current and future MLFs to increased generation capacity at each candidate REZ.

To begin, transmission models are created for each stage of the optimal development path. The models include any future augmentations and installed capacity at REZs. The flows through each line and transformer for each 30-min interval in an entire year are calculated with a direct current approximation using the transmission models and the market modelling results.

Then for each candidate REZ:

- A base case volume-weighted MLF for the year of interest is calculated with the flows through each line and transformer.
- The generator outputs from the market modelling results are modified by scaling up the active power output of candidate REZ, then scaling down the region's remaining generation by the same amount.
- The line and transformer flows are re-calculated with the modified generator outputs.
- The new volume-weighted MLF is calculated with the new line and transformer flows.
- The robustness is found by comparing the base MLF with the new MLF as further active power is added.

The calculations show that the MLF for each candidate REZ experiences a linear decrease as its installed capacity is increased. AEMO has defined the measure for MLF robustness indicated in Table 5, as the additional generation capacity (MW) that can be installed before the MLF changes by -0.05:

Table 5 Added installed capacity before MLF changes by -0.05 and robustness score allocated

Added REZ capacity	≥1000 MW	≥800 MW	≥600 MW	≥400 MW	≥200 MW	<200 MW
MLF robustness score	A	B	C	D	E	F

Effect of energy storage on MLFs

The effect of energy storage on a MLF depends on how well its charging and discharging profiles correlate with the generation profile and load profile. The MLF of a site will improve if the energy storage is charging at times when the generation of the REZ is high and the local area load is low. For example, co-locating a battery with a solar farm could not only assist in shifting the output to times when needed, but could also improve the MLF for the site.

A9.4.4.5 System strength

System strength is an inherent power system characteristic – a measure of its stability under all reasonably possible operating conditions. The ISP assesses future system strength and identifies shortfalls with two measures:

- Synchronous three phase fault level.
- Available fault level.

Both measures are established and currently used in the NEM for system strength.

Synchronous three phase fault level

Definition and current use in the NEM

The synchronous three phase fault level is measured in megavolt-amperes (MVA) and calculated by only including fault contributions from synchronous machines. It is calculated under system normal conditions, and also under credible transmission line, transformer and synchronous machine contingencies.

It is a helpful measure for system strength because it can be used to assess the correct operation of protection systems, the size of voltage deviations due to static voltage control devices, such as switched inductors or capacitors, and the stable operation of existing generation. Fault current is used as a proxy for the level of inertia, fault current, synchronising torque, and other synchronous characteristics which a power system needs. However, it cannot be used as the only metric for all system strength needs, which require detailed electromagnetic transient (EMT) type simulations to fully quantify.

TNSPs have a responsibility under the NER to maintain a minimum synchronous three phase fault level at defined fault level nodes within their network. If there is a shortfall, the TNSP must remediate that shortfall.

The System Strength Requirements Methodology document[9] details the fault level calculation method to be used, defines the fault level nodes in each region, and specifies the minimum fault level requirement at each of these nodes. The fault level requirements are calculated by deriving minimum fault levels from EMT studies that determine the minimum synchronous generator combinations required to be online in each NEM region[10].

[9] AEMO. System Strength Requirements, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf.

[10] AEMO. Transfer Limit Advice – System Strength, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/congestion-information/transfer-limit-advice-system-strength.pdf.

Calculation method in the ISP

The ISP uses the same methodology and requirements to report on potential future shortfalls and possible solutions. The synchronous three phase fault level is calculated in the ISP as follows:

1. The status of all synchronous units (on/off) is extracted from the market modelling outputs[11] for each half-hour interval.
2. The status is applied to the PSS®E network model.
   - The model assumes typical parameters for projected new synchronous plant such as gas peaking, closed cycle gas turbines, and pumped hydro. For pumped hydro the plant is assumed synchronous, apart from Snowy 2.0 units where half are assumed to be inverter-connected units.
   - The model includes the TNSPs' committed synchronous condensers and network upgrades.
   - The model does not assume any system strength mitigation with future inverter-based resources.
3. All inverter-based resources are switched off.
4. The fault level is then calculated at each fault level node using PSS®E.
5. The network model used in the calculations is updated in a time sequential manner to account for future ISP network upgrades.
6. The process is repeated for each half-hour market modelling interval to produce annual fault level node duration curves.

System strength shortfalls are identified when the synchronous three phase fault level falls below the existing minimum fault level requirements for more than 1% of the period.

Available fault level

Definition and current use in the NEM

The available fault level is measured in MVA and defined as the actual synchronous three phase fault level minus the required synchronous three phase fault level specified by the manufacturer of inverter-based resources.

It is a helpful measure for system strength because it assesses whether the control systems of inverter-based resources will operate correctly. It is considered superior to a Weighted Short Circuit Ratio (SCR)[12], because the calculation includes the impact of surrounding inverter-based resources and also their relative electrical distances.

AEMO assesses the impact on system strength of each new generation connection application. There must continue to be sufficient system strength for the stable operation of the network following the new connection. AEMO uses the available fault level calculation to perform this high-level system strength impact assessment, and in determining if a full impact assessment using EMT studies will be required.

If AEMO finds there would be a shortfall after the new connection, the new applicant may be required to provide system strength mitigation. This could be additional equipment or schemes in the applicant's plant, or the applicant paying for a TNSP to perform additional works on the network.

The System Strength Impact Assessment Guidelines[13] describe the assessment process and the methodology for determining available fault level.

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[11] Information about the market modelling methodology is at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

[12] AEMO. System Strength Impact Assessment Guidelines, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Impact_Assessment_Guidelines_PUBLISHED.pdf.

[13] AEMO. System Strength Impact Assessment Guidelines, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/System_Strength_Impact_Assessment_Guidelines_PUBLISHED.pdf.

Calculation method in the ISP

The ISP uses the same methodology to report on potential future shortfalls and possible solutions. The available fault level is calculated in the ISP as follows:

1. The status of all synchronous units (on/off) is extracted from the market modelling outputs[14] for each half-hour interval.
2. The status is applied to the PSS®E network model.
   - The model assumes typical parameters for projected new synchronous plant such as gas peaking, closed cycle gas turbines, and pumped hydro. For pumped hydro the plant was assumed synchronous, apart from Snowy 2.0 units where half were assumed to be inverter-connected units.
   - The model includes future TNSP synchronous condensers and network upgrades.
   - The model does not assume any system strength mitigation with future inverter-based resources.
3. The impedance of inverter-based resources is modified according to minimum required SCR (assumed to be 3) and unit MW capacity.
4. Two fault levels for each node are calculated using PSS®E: three phase synchronous fault level (contributed by synchronous resources only) and then total three phase fault level required for inverter based resources to operate in a stable manner, based on the previous SCR assumptions.
5. Available fault level (AFL) is then calculated for each node by subtracting the total required fault level from the actual synchronous fault level. A negative outcome indicates a need for additional synchronous fault level at the location. This reduced equation provides an indication of the positive contribution from synchronous resources, and the current understanding of interplay between synchronous resources and inverter-based resources with relation to system strength. It is important to note that this is an area of evolving understanding and technical innovation.
6. The network model used in the calculations is updated in a time sequential manner to account for the proposed ISP network upgrades.
7. The process is repeated for each half-hour market modelling interval to produce annual fault level node duration curves.

System strength shortfalls are identified when the available fault level becomes negative.

When calculating the shortfalls in REZs, only the shortfalls due to the requirements of new generation connecting at key buses within the REZ are shown.

This is in order to be able to separate the remediation needed for fault level nodes (which is a TNSP responsibility) and the new generator connection remediation (which is the connecting party's responsibility). For this reason, for the REZ shortfalls presented, it is assumed firstly that the fault levels at the regional fault level nodes have already been maintained prior to calculating these shortfalls.

Shortfalls are calculated based on generation needing to maintain a short circuit ratio of 3 at their connection point, even after a credible contingency.

System strength shortfalls in the ISP

Following the Actionable ISP changes to the NER, assessment and declaration of system strength requirements and shortfalls is now prepared annually through a separate System Strength Report. AEMO is expecting to release the first of these annual reports by the end of 2020, and information about possible system strength shortfalls provided in the ISP is for information only.

[14] Information about the market modelling methodology is at https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

Possible solutions

When a shortfall is found, using either the synchronous three phase fault level or the available fault level, possible solutions are:

- Conversion of retiring synchronous plant to synchronous condensers.
- Contracts with synchronous units with existing generation to remain online.
- Contracts with synchronous units to come online in synchronous condenser mode.
- Installation of new synchronous condensers.
- Additional AC transmission.
- Connection of new synchronous generation (for example, temporary plant for interim solutions).
- If only marginal, reduced impedances, such as connection transformers.
- Improved control systems such as grid forming inverters[15].

A9.4.4.6 Inertia

AEMO is required to operate the power system to meet the frequency operating standards using services provided by the local TNSP. In 2018, AEMO determined two levels of inertia for each NEM region[16] that must be available for dispatch when a region is at credible risk of islanding, or islanded:

- The Minimum Threshold Level of Inertia is the minimum level of inertia required to operate an islanded region in a satisfactory operating state.
- The Secure Operating Level of Inertia (SOLI) is the minimum level of inertia required to operate the islanded region in a secure operating state.

AEMO can agree to adjustments to the minimum threshold level of inertia or the secure operating level of inertia if inertia support activities (such as the provision or procurement of Fast Frequency Response (FFR)) will result in lower levels of synchronous inertia being necessary to meet system security requirements.

The Inertia Requirements Methodology document[17] details the minimum inertia calculation method to be used, defines the inertia sub-networks, and specifies the minimum threshold and secure operating levels of inertia for each inertia sub-network.

Calculation method in the ISP

The regional inertia is calculated in the ISP as follows:

1. The status of all synchronous units (on/off) is extracted from the market modelling outputs[18] for each half-hour interval.
2. The corresponding inertia constants for all online generation is then obtained.
   - The model assumes typical parameters for projected new synchronous plant such as gas peaking, CCGT, and pumped hydro. For pumped hydro the plant is assumed synchronous, apart from Snowy 2.0 units where half are assumed to be inverter-connected units.
   - The inertia constants for future TNSP synchronous condensers are also added into the calculations for the time periods they expected to be in service, for example the high inertia synchronous condensers in South Australia.

[15] Currently there is a low level of experience in costs and performance of grid forming converters, and as such generation planting outcomes assume costs for grid following inverter options only.

[16] AEMO, 'Inertia Requirements Methodology. Inertia Requirements and Shortfalls', 1 July 2018, at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf.

[17] AEMO. 2018 Inertia Requirements Methodology, at https://www.aemo.com.au/-/media/files/electricity/nem/security_and_reliability/system-security-market-frameworks-review/2018/inertia_requirements_methodology_published.pdf.

[18] Available via https://aemo.com.au/en/energy-systems/electricity/national-electricity-market-nem/nem-forecasting-and-planning/scenarios-inputs-assumptions-methodologies-and-guidelines.

3. The total inertia is then calculated for each region by summating all the inertia constants.
4. The process is repeated for each half-hour market modelling interval to produce annual inertia duration curves.

Inertia shortfalls are identified when the typically dispatched regional inertia falls below the minimum inertia thresholds for the period, and the risk of the region needing to be operated at risk of, or as an island is deemed to be likely.

Inertia shortfalls in the ISP

Following the Actionable ISP changes to the NER, assessment and declaration of inertia requirements and shortfalls is now prepared annually through a separate Inertia Report. AEMO is expecting to release the first of these annual reports by the end of 2020, and information about possible inertia shortfalls provided in the ISP is for information only.

Possible solutions

When a shortfall is found, possible solutions are:

- Conversion of retiring synchronous plant to synchronous condensers.
- Contracts with synchronous units with existing generation to remain online.
- Contracts with synchronous units to come online in synchronous condenser mode.
- Installation of new synchronous condensers with high inertia flywheels.
- Additional regional interconnection in order to reduce the probability of the region operating as an island.
- Connection of new synchronous generation (for example, temporary plant for interim solutions).
- Fast Frequency Response, for example from inverter-based generation or batteries, or fast load switching.
- Control scheme that reduces the maximum contingency size.

It is possible to mitigate a number of system service requirements such inertia, system strength and voltage control with similar solutions, and any mitigation options should also consider these aspects concurrently.

A9.4.5 Consideration of the cost of transmission

Capital cost estimates of transmission network projects are indicative and are prepared from desktop studies based on the latest cost data available within AEMO[19]. These cost estimates include planning estimates of following components:

- Preliminaries – site survey, geotechnical and location services.
- Design and engineering.
- Primary plant (towers, conductors, transformers, switchgears, static/dynamic reactive plant).
- Secondary systems including control and protection.
- Civil works including clearing, excavation, earthworks, foundation, support structure.
- Building for secondary equipment.
- Testing and commissioning of plant.
- Project management.

AEMO's application of unit cost estimates of transmission assets are provided in the Input and Assumptions Workbook.

[19] For the 2020 ISP, the latest cost data available is as at February 2020.

Cost estimates of transmission lines are based on 110% of the straight-line distance between two connection points. A 5% of overall capital cost is been allowed for land and easement. The specific route will only be confirmed during detailed preparation of a RIT-T. An extensive range of factors may affect the project cost including (but not limited to) environmental factors affecting line route, biodiversity considerations, land acquisition or easement cost, construction cost implications arising from route dynamics, currency fluctuations and construction contractor costs in the proposed construction period.

Cost estimates of transmission networks projects currently undergoing RIT-T by TNSPs are obtained from the RIT-T or latest information available[20].

All capital cost estimates are considered to be within ±30% tolerance. A 1% of capital cost is generally assumed as operation and maintenance cost.

[20] For the 2020 ISP, cost estimates of transmission networks projects currently undergoing RIT-T by TNSPs were obtained from the RIT-T or latest information available in March 2020.

A9.5. Model outputs

The engineering assessment and market modelling processes together produce the ISP recommendations. Outputs are created throughout the process to inform the ultimate ISP recommendations. These are summarised below with their enabling processes.

The **capacity outlook modelling process, informed by engineering assessment**, produces a high-level set of outputs which are used to inform further ISP processes:

- Optimised broad generation and storage build (and closures) as well as transmission network expansion is determined by the capacity outlook modelling process (see Appendix 4).
- Preferred capacity expansion options such as generation, storage, inter- and intra-regional network expansions and REZs are validated by time sequential market modelling and engineering assessment (see Appendix 6 and 7).
- Estimated total costs and benefits of the preferred generation, storage and transmission expansions are based on the outputs of the capacity outlook modelling results (see Appendix 2).

The **time sequential model process, validated through engineering assessment**, produces a more refined set of outputs that ultimately feed into the ISP recommendations, and particularly provide:

- Validation of the costs and benefits of key development paths.
- Confirmation of system reliability and operability under key development paths.

All information gathered from the ISP process is collated to form the optimised generation, storage and network outlook, and perform cost benefit analysis. The process of selecting the optimal development path is outlined in the body of this Final 2020 ISP.

Key outputs that assist in the understanding and verification of the ISP recommendations are collated and published within the Generation Outlook[21] and Transmission Outlook[22] data files.

[21] At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp.
[22] At https://www.aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2020-integrated-system-plan-isp.