Assumptions for South Australian GPG in the 2018 Integrated System Plan

August 2019

Important notice

PURPOSE

This document has been prepared by AEMO to assist the Australian Energy Regulator understand the modelling AEMO undertakes for the purposes of its Independent System Plan (ISP). It has been prepared using information available at 24 June 2019. Information made available after this date may have been included in this publication where practical.

DISCLAIMER

This document contains assumptions and estimates regarding future plant, plant performance, market conditions and other matters, that have been prepared for AEMO's own internal purposes. By their very nature, assumptions about future matters are uncertain and actual plant, performance, conditions and outcomes will be different to that assumed.

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VERSION CONTROL

Version	Release date	Changes
1	July 2019	Initial draft
2	August 2019	Final version

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1. Introduction

On 4 July 2019, the Australian Energy Regulator wrote to AEMO seeking clarification of the basis for minimum capacity factor constraints (CF constraints) applied in the 2018 ISP. The AER sought this for Osborne Power station (OPS) (60%), Pelican Point Power Station (PPPS) (50%) and Torrens Island Power Station A (TIPS A) (15%). The AER advised that ElectraNet used similar assumptions in their Project Assessment Conclusions Report (PACR) for Project EnergyConnect, although with a constraint on Torrens Island Power Station B (TIPS B) (20%) instead of TIPS A. ElectraNet has advised that it applied constraint of 25% to Torrens Island B in the PACR.

The AER requested information on the following:

a) The methodology and provision of the assumptions and calculations used to derive minimum capacity factor constraints (refer section 2), including:
   i. Why these constraints were applied to these particular generators (section 3).
   ii. Why constraints were applied after 2019 only in SA (section 3).
   iii. Why these constraints were not applied to Barker Inlet Power Station and TIPS B (section 3.1).
   iv. In which stages of AEMO's modelling the minimum capacity factor constraints were applied (section 2).

b) Historical operation of these gas plants and whether their current operation is indicative of future operation in the market (section 3.2).

AEMO has met several times with AER staff to clarify the inputs and assumptions used when developing the 2018 ISP, the reasons behind these inputs and assumptions, and how these were applied in the modelling together with the effect. This report incorporates the outcomes of those discussions and the information requested.

2. Modelling methodology

For the 2018 ISP, AEMO used a combination of economic and power system modelling packages to model the future power system under a wide range of scenarios. This enabled AEMO to robustly analyse the economic and technical requirements for each development pathway. With the extent of change envisaged in the future power system, appropriate detailed power engineering modelling of the power system as a whole was an essential component of the analyses – to ensure that any economic projections were operationally feasible and to identify the technical requirements to implement the projected future resource mix. Consideration of gas in a co-optimised manner was another essential part of these robust plans for the development of the NEM.

AEMO's forecasting suite of tools consisted of several separate models which complemented each other to identify the optimal generation and transmission pathway in the long-term across the range of different scenarios. As the models were required to deliver a range of planning objectives, maintaining internal consistency and complementarity across the models was a critical requirement.

AEMO's Integrated Model (IM) co-optimised electricity generation and transmission investment and withdrawals, along with gas production and pipeline infrastructure, to efficiently meet future operational demand and government policy objectives (such as renewable generation development) at lowest cost.

The objective of the capacity outlook models (including the IM and Detailed Long-Term (DLT) model), in combination, was to minimise the capital expenditure and generation production costs over the long-term planning outlook (at least 20 years), subject to:

- Ensuring there was sufficient supply to reliably meet demand at the current NEM reliability standard, allowing for inter-regional reserve sharing.
- Meeting policy objectives.
- Observing physical limitations of generation plant and transmission system.
- Accounting for any energy constraints on resources.

The IM model also incorporated sector-coupling across gas and electricity, given the critical dependencies between the gas and electricity sectors.

It was necessary to use some reasonable simplifying assumptions for computational manageability due to the size of the problem and the length of the planning horizon, including:

- Reducing the number of integer decision variables by linearizing generation and transmission build, and operational and retirement decisions (although many of these key linear decisions were validated via sensitivity analysis, applying 'with' and 'without' modelling as required).
- Using minimum capacity factors and minimum operating levels to represent minimum technical and economic duty cycles for specific thermal generators across the NEM (these were only relevant in the capacity outlook models, and the time sequential analysis in the final stage of modelling did not use the minimum capacity factors – see next).

Minimum capacity factors were used in the capacity outlook model to represent unit commitments and technical constraints that affect gas consumption. This ensured that resultant projections of thermal generator operation were consistent with reasonable duty cycles in the face of competing lower emission alternatives and included the flexibility for units to potentially change to two shift operation.

The resolution of the capacity model meant that explicit modelling of unit commitment decisions within a day was problematic – even when the chronology was preserved. As a result, the generation and transmission outlook developed by the capacity outlook model was validated using one of several time-sequential models that mimicked the dispatch process used by NEMDE in the NEM.

For the 2018 ISP, the time-sequential model was applied to snap-shot years and considered the modelled time horizon in much higher resolution to validate unit commitment and operational assumptions. These feedbacks were critical from a whole-of-system perspective to make sure that gas consumption in the capacity outlook model was representative and could be adequately supplied given reserve estimates and pipeline constraints in the gas system. It also enabled inclusion of critical system security requirements in the model.

Two decisions optimised for each generating unit within the time-sequential model were the unit commitment and the level of dispatch:

- Unit commitment optimisation considered the generator units' assumed start-up cost, minimum uptime, and minimum stable operating level[1]. For example, this considered the economics of periods where it was optimal to keep generators on at low generation levels, even when making a loss, to avoid the cost of restarting later.
- The level of dispatch in this time-sequential model was influenced by game-theoretic bidding strategies (determined using Nash-Cournot logic within the model) to appropriately represent the mix of gas and coal-fired generation. AEMO used short-run marginal cost bidding informed by the game theoretic bidding to assess market benefits in the ISP (that is, assuming perfect competition to maximise economic efficiencies).

Insights and outcomes of these time-sequential model simulations were then fed back into the generation expansion models in the form of minimum capacity factors to replicate material technical constraints and gas consumption requirements. For the purposes of cost-benefit analysis, the market benefits were assessed from the total system costs from the capacity outlook models.

Unit commitment optimisation and minimum stable levels were not appropriate for peaking plant when using hourly model resolution in the market model. These units were capable of starting up to operate for minutes rather than hours, and it would not be appropriate to impose a constraint in the market model that forces them to remain operating at their technical minimum stable level for an entire hour if dispatched. While these units do have minimum stable levels, on average across the hour they may be generating at a lower level due to changes in unit commitment. These peaking units also do not materially impact the annual gas consumption needed for the gas-electricity integrated market model.

As described further in section 3, minimum capacity factors and minimum operating limits were applied in the 2018 ISP to represent key system security, operational, and fuel supply considerations relevant to each plant. It is essential to represent such constraints when running economic models, as without them, the models would produce outcomes that did not adequately represent the physical constraints in the gas and electricity systems.

AEMO's modelling therefore reflected the expected real-world conditions for this plant – either produced by the market, or where the market did not dispatch sufficient synchronous generation, produced by directions by AEMO to ensure the minimum number of synchronous generation units were on line for system strength, inertia, and frequency control in the event of islanding.

Minimum capacity factors (in the capacity expansion plan) and unit commitment decisions (in the time sequential modelling) were imposed on generators that:

- Were required to be on-line for system security purposes.

[1] For the 2018 ISP, refer to:

ACIL Allens Fuel and Technology Cost Review Report in the ISP Database: http://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/NTNDP/Historical/Fuel_and_Technology_Cost_Review_Data_ACIL_Allen.xlsx

2018 ISP Input and Assumptions Workbook, Generation tab: http://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/2018-Integrated-System-Plan--Modelling-Assumptions.xlsx

- Were involved in unit commitment constraints (such as "that at least two units must be on-line at all times")
- Were likely to materially impact the level of annual gas consumption
- Had limited flexibility to start up and shut down (such as coal-fired generation).

Given the problem size that the Capacity Outlook models solve, some coarseness is required to keep the problem tractable. For the IM, this is a monthly load duration curve (LDC) methodology which does not maintain chronology of time within each month. For the DLT, this is a daily chronological representation that maintains chronology, with some hourly aggregation to represent 24 hours as eight separate time slices. This is a much more granular representation, but still cannot appropriately calculate unit commitment decisions given model coarseness, and therefore capacity factor limits are applied.

The PLEXOS® model implements the interaction of these capacity factors and unit commitment decisions by applying properties (Minimum Load[2] and Minimum Capacity Factor Year). The combination of minimum capacity factors and 'must run' minimum load settings are not additive – the model identifies which constraint would be the most restrictive and satisfies both simultaneously (and identifying if the constraints conflict and cause problem infeasibilities). For example, the minimum load property requires a generator to always be online at an operating capacity above the minimum load level. A minimum capacity factor requires a generator to operate to achieve a total production volume over a period of time. The combination of these settings would require all periods to operate at the minimum load, and if the capacity factor limit is greater than the energy that would be produced if operating at minimum load across the period of time, then some periods (the periods whereby increased operation would minimise system costs over the modelling period) would have increased operation to achieve the minimum total energy limit. The periods that are optimised to operate at higher production volumes are typically peak periods where increased energy across the system is required.

[2] The must run Minimum Load property can also be represented in PLEXOS as Minimum Capacity Factor, which is an hourly energy constraint. This is equivalent to Minimum Load. The Minimum Capacity Factor Year constraint applies an energy constraint to a multi-period time horizon, meaning that dispatch flexibility is available.

3. Modelling Assumptions

The goal of the 2018 Integrated System Plan (ISP)[3] was to develop the most economic, efficient future development plan, that delivered a reliable and secure power system at lowest cost to consumers.

In regions other than South Australia, minimum capacity factor constraints were not applied to GPG in the 2018 ISP, because the outlook was very different to South Australia. The approach undertaken enabled modelling in the 2018 ISP to assess the uncertainty surrounding GPG operation in regions with significant coal and renewable generation. Queensland, for example, was projected to be oversupplied with energy in the medium term, with abundant coal and gas generation, and expected significant development of renewable generation driven by the QRET policy.

As noted in section 2, the modelling involved three stages of modelling which were then iterated to ensure that outcomes were not only economically optimal but also realistic representations of the real-world limits. In the capacity outlook models, unit commitment was represented through minimum capacity factors to simulate technical constraints that affect gas consumption. The time-sequential modelling stages were then used to validate unit commitments, with operational assumptions applied to snap-shot years and considered the modelled time horizon in much higher resolution. These feedbacks were critical from a whole-of-system perspective to make sure that gas consumption in the capacity outlook model was representative and could be adequately supplied given reserve estimates and pipeline constraints in the gas system. It also enabled inclusion of critical system security requirements in the model.

Insights and outcomes of these time-sequential model simulations were then fed back into the generation expansion models in the form of minimum capacity factors to replicate material technical constraints and gas consumption requirements, and the process iterated, until the outcomes converged on optimal solutions that were also operationally robust.

In the 2018 ISP, AEMO applied constraints on GPG in South Australia in the capacity outlook modelling stages (only) to ensure that the forecasts reflected a combination of goals and were realistic, such as:

- Considering generator technical limits.
- Reflecting typical utilisation based on historical profiles of generation and expectations of future dispatch, and also reflecting typical annual gas consumption requirements.
- Ensuring that the required minimum number of synchronous generations were on-line for system security purposes.

All of the constraints applied in the 2018 ISP are described in the 2018 assumptions workbook[4] (Generation Limits tab – bottom of first and second tables) available from the AEMO website.

3.1 Plant technical limits

The minimum generation for each generator is asset-specific and is a technical limitation which AEMO factored into its assessment for the 2018 ISP.

- In the case of TIPS B, a minimum operating level rather than a minimum capacity factor was applied in modelling to utilise TIPS B as the least-cost approach to satisfy the critical system strength constraint (minimum number of units of appropriate size to deliver required fault level outcomes at the designated

[3] AEMO. *2018 Integrated System Plan*, available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/Integrated-System-Plan

[4] AEMO. *2018 ISP assumptions workbook* (refer Generation Limits tab – bottom of first and second tables): https://www.aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/ISP/2018/2018-Integrated-System-Plan--Modelling-Assumptions.xlsx

fault level nodes in South Australia). The system security constraint was relaxed once the new double circuit interconnector, EnergyConnect, was commissioned, between 2022 to 2024 in the 2018 ISP.

- In the case of other units, minimum capacity factors used to reflect typical dispatch ensured that minimum operating levels were observed on OPS, PPPS, and TIPS A. TIPS A was assumed to be retired/mothballed in 2021 as per public announcements at the time (AGL has recently announced[5] an extension to part of TIPS A). MCFs were released on Osborne and Pelican Point once EnergyConnect was commissioned.
- As Barker Inlet Power Station is an ultra-flexible peaking gas plant (able to go from offline to full speed in less than 5 minutes) and was not required to manage system security, no constraint was applied.

3.2 Typical dispatch of plant

The minimum capacity factors applied in the 2018 ISP at OPS, PPPS and TIPS A ensured that dispatch patterns in the modelling outcomes more accurately reflected the actual dispatch of synchronous generation expected in the real world. The minimum capacity factors reported in AEMO's inputs and assumptions workbook were derived as an endogenous input informed by iterations of market modelling and power system modelling and validated against actual observed outcomes and real-world technical limitations of the plant.

Historically, there has been an increased reliance on directions[6] to maintain the system in a secure and reliable operating state in South Australia. In many cases, the requirement for a minimum number of synchronous generator unit commitments would be (and has been) delivered through the market, avoiding the need for AEMO directions, and masking the otherwise underlying critical need for minimum number of synchronous generators online at any time. Where the market did not dispatch the required minimum number of synchronous generating units, AEMO has and will continue to direct units online, and these would then factor into resultant monitoring of total dispatch outcomes.

AEMO analysed historical generation profiles for power stations to confirm the minimum capacity factor assumed as an input constraint in the 2018 ISP, while also validating outcomes against the broader set of criteria for units as described earlier (including minimum operating levels and system security requirements):

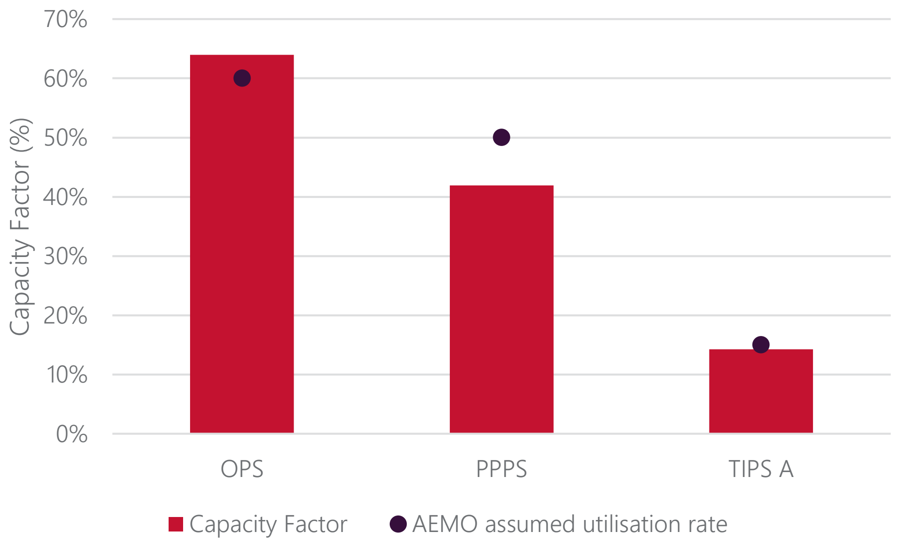
- A 60% minimum capacity factor was applied to OPS. This compares to an observed 64% utilisation recorded for the plant in Financial Year Ending (FYE) 2017 and 2018.
- A 50% minimum capacity factor was applied to PPS. This compares to an actual recorded utilisation of 42% in FYE 2017 and 2018.
- A 15% minimum capacity factor was applied to TIPS A. This compares to an actual recorded utilisation of 14% in FYE 2017 and 2018.

Figure 1 compares actual outcomes with AEMO's assumptions. AEMO will continue to monitor actual dispatch outcomes, stakeholder feedback, and market outlook, and update these plant specific outcomes if required.

[5] AGL notice to Australian Stock Exchange 2 August 2019 – TIPS A first two units mothballed from late 2020, third 2021, fourth 2022.

[6] AEMO. *Operational and market challenges to reliability and security in the NEM*, available at: https://www.aemo.com.au/-/media/Files/Media_Centre/2018/AEMO-observations_operational-and-market-challenges-to-reliability-and-security-in-the-NEM.pdf.

Figure 1 Actual utilisation compared to AEMO assumed minimum capacity factor, FYE17 to FYE18



3.3 Power system requirements

At present, a minimum local commitment of large synchronous generating units is needed in South Australia to provide essential power system services, including:

- System strength (and fault current)
- Inertia (and Rate of Change of Frequency (RoCoF))
- Frequency control and operating reserves

The 2018 ISP identified that the most efficient development pathway for South Australia to address these requirements would include high-inertia synchronous condensers and a new interconnector to New South Wales.

System strength (and fault current)

At present, local commitment of large synchronous generating units is required in South Australia to maintain system strength[7]. In October 2017, AEMO declared a fault level shortfall in South Australia[8]. ElectraNet is procuring four large synchronous condensers to meet this fault level shortfall[9]. These units are designed as a cost-effective, no-regrets way to address the declared shortfall that currently exists in the system. However, this solution does not address all of the requirements for system security in South Australia for the future:

- The synchronous condensers address the declared minimum fault level gaps (and provide inertia) only for up to 2000 MW of utility scale asynchronous (inverter connected) generation online. Additional steps were expected to be required to provide for more asynchronous generation online, dependent on the location of the plant and its characteristics. The “do no harm” rules relate to new connecting utility scale generation to ensure that their connection does detract from system strength.
- This does not guarantee that system strength in other areas will be sufficient, or that the system be able to be returned to a secure operating state, during outages. Critical outages such as prior outage of

[7] AEMO. System strength requirements methodology. System strength requirements and fault level shortfalls; July 2018: https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-MarketFrameworks-Review/2018/System_Strength_Requirements_Methodology_PUBLISHED.pdf

[8] AEMO. *Second Update to the 2016 NTNDP*, available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan.

[9] ElectraNet. *Strengthening South Australia's Power System*, available at: https://www.electranet.com.au/what-we-do/projects/power-system-strength/.

synchronous condenser, Para Static Var Compensator, or Tailem Bend – South East 275kV line, are expected to require additional measures to be in place.

- This does not address other potential system security requirements, such as voltage control, damping of oscillations and short-term power quality.
- This does not address future potential system strength declines in the metropolitan area with over 1 GW of distributed energy resources (DER), primarily comprising rooftop PV with much less sophisticated control systems than utility scale asynchronous generation.

Inertia (and RoCoF)

In response to a ministerial direction issued under the Essential Services Act 1981 (SA), AEMO has implemented constraint equations to limit South Australian RoCoF to 3 Hz/s for the non-credible trip of the Heywood Interconnector[10]. The basis of this request was to mitigate the risk of a state-wide blackout from a double-circuit contingency event.

AEMO has determined the inertia requirements for South Australia[11] and declared an inertia shortfall in South Australia[12]. ElectraNet's proposed synchronous condenser solution (due to be delivered in late-2020) has been designed to provide additional synchronous inertia (4,400 MWs) to address the minimum synchronous component of the inertia shortfall and will improve the RoCoF constraint by up to approximately 500 MW in either direction.

Frequency Control

Traditionally, frequency control was provided through the unused capacity of synchronous generators. Primary frequency control in South Australia has been impacted by increasing penetration of wind and solar generation and fewer synchronous generators in the supply mix.

The current Frequency Operating Standards[13] (FOS) set out that following a multiple contingency event, AEMO should use reasonable endeavours to return the frequency to between 49.85 Hz to 50.15 Hz within 10 minutes. The loss of the Heywood interconnector is one such event.

Further, the NER requires that AEMO must use reasonable endeavours to:

- Control the power system frequency (NER 4.4.1(a))
- Ensure that the FOS are achieved (NER 4.4.1(b))
- Ensure that adequate facilities are available and are under the direction of AEMO to allow the managed recovery of the satisfactory operating state of the power system. (NER 4.4.2(d))

Additionally, the South Australian Government has made a ministerial direction to limit RoCoF to 3 Hz/s[14].

AEMO's capability to restore frequency in South Australia following a separation event requires online services that provide:

- Inertial response (within a fraction of second) – Inherent response from synchronous machines and associated masses to arrest deviations in frequency. This can be in part provided through fast frequency response of advanced power electronics associated with inverter connected generators, and in particular battery energy storage systems.

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[10] AEMO. *Electricity Market Notice 55358*, 12 October 2016, available at: https://www.aemo.com.au/Market-Notices.

[11] AEMO. Inertia Requirements Methodology. Inertia Requirements and Shortfalls; July 2018: http://aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/System-Security-Market-Frameworks-Review/2018/Inertia_Requirements_Methodology_PUBLISHED.pdf

[12] AEMO. *2018 NTNDP*, available at: https://www.aemo.com.au/Electricity/National-Electricity-Market-NEM/Planning-and-forecasting/National-Transmission-Network-Development-Plan.

[13] Reliability Panel AEMC. Frequency Operating Standards, available at: https://www.aemc.gov.au/sites/default/files/2019-04/Frequency%20operating%20standard%20%E2%80%93%20effective%201%20January%202020.pdf.

[14] Note that this is different from the Protected Event rule which would treat the contingency as credible for purposes not strictly related to frequency restoration (e.g. transient stability, FCAS, etc.).

- Primary frequency control (within a few seconds) – Active power controls act in a proportional manner to respond quickly to measured changes in local frequency and arrest deviations through changes in their active power output in a timeframe longer than that of the inertial response). It is automatic and not an outcome of centralised system control and begins immediately after a frequency change beyond the specified level is detected.
- Secondary frequency control – Automatic generation controls and manual dispatch commands act to restore frequency to 50 Hz and relieve providers of primary frequency control.
- Operating reserves – The capability to respond to large continuing changes in energy requirements.
- Grid formation – The ability to set frequency. At present, the only viable grid forming technology of the scale required that has been demonstrated anywhere in the world are synchronous generating units.

Since NEM start (1998), the Heywood interconnector has experienced a non-credible separation event approximately once every three years. Additional interconnection and provision of sufficient frequency control is critically necessary to manage the potential risk of a system black event following this one-in-three-year event. In the absence of additional interconnection (which of itself reduces the likelihood of separation events by establishing two double circuit ties instead of just the one), AEMO's reasonable endeavours to maintain the Frequency Operating Standard (FOS) in South Australia will include the pre-contingent provision of some minimum level of these services.

While emerging technologies (e.g. grid forming inverters and battery systems) may eventually be capable of providing some of these services, they are not yet proven to be scalable for operation in a large islanded system the size of South Australia, and there is no comparable demonstration of this at this scale anywhere in the world. The current batteries in South Australia are not able to provide all of these essential services.

Wind and solar generation have proven their capability to provide a level of frequency control but cannot provide firm operating reserves and are not active in the Frequency Control Ancillary Service (FCAS) markets.

3.4 Planning Assumptions applied in the 2018 ISP

Summary of planning assumptions

The planning assumptions applied in the 2018 ISP are summarised in the following table, and detailed in the subsequent sections.

Table 1 Planning assumptions for the 2018 ISP

<table>
<tr><th rowspan="2">Power System Requirement</th><th colspan="8">Planning assumptions used in the 2018 ISP</th></tr>
<tr><th>At least 4 synchronous generating units</th><th>At least 3 synchronous generating units</th><th colspan="2">At least 2 synchronous generating units</th><th colspan="2">At least 1 synchronous generating unit</th><th colspan="2">No synchronous generating units</th></tr>
<tr><td colspan="9">SYSTEM NORMAL, REQUIREMENT FOR POWER SYSTEM SECURITY</td></tr>
<tr><td>System strength & fault current</td><td>NOW</td><td></td><td colspan="2"></td><td colspan="2"></td><td>SYNCONS</td><td>ENERGY CONNECT</td></tr>
<tr><td>Operating reserves for ramping</td><td></td><td></td><td>NOW</td><td>SYNCONS</td><td colspan="2"></td><td colspan="2">ENERGY CONNECT</td></tr>
<tr><td colspan="9">SYSTEM NORMAL REQUIREMENT TO SURVIVE 1-IN-3 YEAR SEPARATION EVENT†</td></tr>
<tr><td>Grid formation</td><td></td><td></td><td colspan="2"></td><td>NOW</td><td>SYNCONS</td><td colspan="2">ENERGY CONNECT</td></tr>
<tr><td>Inertia and RoCoF</td><td></td><td></td><td colspan="2"></td><td colspan="2">NOW‡</td><td>SYNCONS</td><td>ENERGY CONNECT</td></tr>
<tr><td>Primary frequency control</td><td></td><td></td><td colspan="2"></td><td>NOW</td><td>SYNCONS</td><td colspan="2">ENERGY CONNECT</td></tr>
<tr><td>Secondary frequency control</td><td></td><td></td><td>NOW</td><td>SYNCONS</td><td colspan="2"></td><td colspan="2">ENERGY CONNECT</td></tr>
<tr><td>Operating reserves for energy balance</td><td></td><td></td><td>NOW</td><td>SYNCONS</td><td colspan="2"></td><td colspan="2">ENERGY CONNECT</td></tr>
<tr><td colspan="9">SYSTEM NORMAL MINIMUM REQUIREMENT</td></tr>
<tr><td>Minimum requirement</td><td>NOW</td><td></td><td colspan="2">SYNCONS</td><td colspan="2"></td><td colspan="2">ENERGY CONNECT</td></tr>
</table>

† A "non-credible" separation event has occurred approximately once every three years since NEM start. With Energy Connect, the separation risk would be reduced.

‡ RoCoF risk is currently managed with a 3 Hz/s RoCoF constraint on the Heywood interconnector.

Current system - before synchronous condensers and EnergyConnect

As described, GPG currently plays a vital role in South Australia, and without other developments, ongoing operation of the GPG is essential for reliability and security of the future power system.

Currently, a minimum commitment of synchronous generation in South Australia is required in real-life operations to maintain system strength. As these minimum requirements are critical for system security in the South Australian region, where the market does not deliver these minimum requirements, AEMO will direct participants (and continues to be forced to do so in the live market) to ensure that this minimum requirement is met. Accordingly, any modelling of the power system must recognise these real limits.

While there were many feasible combinations of units that could satisfy the minimum system strength and inertia requirements, AEMO's 2018 planning studies distilled this limit to a least-cost implementation that required four (4) Torrens Island B (TIPS B) units online above minimum generation (≥40 MW each) at all times to ensure supply adequacy for system strength purpose with the 3Hz RoCoF constraint in place and only one synchronous interconnector (i.e. Heywood). For the purposes of the 2018 ISP, this was sufficient to assess and develop the resultant development plans. Other combinations of generating units can and do apply to meet this requirement, but do not change the outcomes of the 2018 ISP in any material manner. Updated combinations that can provide equivalent outcomes are described in the transfer limits advice for South Australia system strength[15].

[15] AEMO. Transfer Limit Advice – South Australia System Strength, available at https://www.aemo.com.au/-/media/Files/Electricity/NEM/Security_and_Reliability/Congestion-Information/2018/Transfer-Limit-Advice---South-Australian-System-Strength.pdf.

After synchronous condensers, and prior to EnergyConnect

The concept of "system normal" as an entirely intact power system is rarely reflected in practice as a static condition – generation and transmission are often coming into and out of service. The resultant "new system normal" state then needs to be maintained in or quickly returned to a secure operating state.

AEMO's planning assumptions in the 2018 ISP were that, to the extent practicable, the power system should remain in a secure operating state for all system normal conditions. Furthermore, the Frequency Operating Standards (FOS) should be maintained and system black should be avoided for any reasonably foreseeable contingency event (e.g. a non-credible SA separation event that has occurred approximately one in every three years since NEM start).

The ISP projected that the installation of four synchronous condensers (including flywheels) would address the identified system strength gap and the minimum synchronous component of the declared inertia shortfall. However, AEMO did not assume that the four synchronous condensers would address all requirements for system security in South Australia. Rather, AEMO's approach was consistent with ElectraNet's economic case for the synchronous condensers[16], which assumed a requirement to keep two large synchronous generators online at all times.

For the 2018 ISP, AEMO assumed that, following the installation of the four synchronous condensers (including flywheels) and prior to the implementation of EnergyConnect, at least two large synchronous generator units in South Australia would be required online at all times. AEMO's detailed studies have shown that this is a minimum requirement for security of South Australia. AEMO has assumed this requirement for the following reasons:

- Operating reserves for ramping
- Secondary frequency control following a separation event
- Operating reserves for energy balance following a separation event

Operating reserves for ramping

AEMO has reviewed historical wind and demand ramping events, which highlights the need for operating reserves to be provided to prevent overloading of the Heywood interconnector. For example, over a 30-minute period, South Australia can experience an un-forecast 600 MW deficit in energy balance (e.g. a drop in wind generation). Without local operating reserves, this deficit will be balanced by increased flow on the Heywood interconnector. At full registered import capacity, the Heywood interconnector has a 200 MW headroom before breaching its satisfactory limit and risking separation.

While some fast start plant can support this need, there is a delay in bringing units online through the dispatch process (10 to 25 minutes depending on the bidding of fast-start plant). Two large synchronous generators can provide approximately 500 MW of ramping services over a 30-minute period, which is enough to prevent breaching the satisfactory limit on Heywood for an un-forecast ramping event.

Secondary frequency control following a separation event

Following a one-in-three-year non-credible SA separation event, AEMO is required to restore frequency in South Australia to the 49.85 to 50.15 Hz range within 10 minutes – see section 3.3. The ability to achieve this requires secondary frequency control services (e.g. contingency FCAS). Preliminary modelling indicates at least two large synchronous generators would be required online prior to a separation event to achieve this standard. These services cannot reliably be provided by fast-start plant within the stabilisation and recovery timeframes required in the FOS.

[16] ElectraNet. *Addressing the System Strength Gap in SA – Economic Evaluation Report*, available at https://www.aer.gov.au/system/files/ElectraNet%20-%20System%20Strength%20Economic%20Evaluation%20Report%20-%2018%20February%202018.PDF.

Operating reserves for energy balance following a separation event

Following a one-in-three year non-credible SA separation event, assuming the system frequency has been stabilised through adequate provision of secondary frequency control, operating reserves will then be required to maintain energy balance.

For example, load and intermittent generation will continue to change from minute to minute. In the event of a separation event, AEMO can begin to bring fast-start plant online to provide operating reserves and to begin to restore load that was shed by the Under-Frequency Load Shedding (UFLS) system. In the 10 to 25 minutes that it can take to bring these fast-start units online, if the system does not have sufficient operating reserves to be able maintain the supply–demand balance as generation and load varies minute to minute, frequency will continue to vary and other measures may be needed to preserve frequency within the limits while the units are brought online, potentially including the undesirable action of shedding further customers.

At least two large synchronous generating units, online prior to a separation event, with sufficient operating reserves to maintain energy balance during subsequent operations (which may include, for example, variation of demand or rapid changes in wind generation), would be needed to support the orderly restoration of load.

After synchronous condensers and EnergyConnect

For the 2018 ISP, AEMO assumed that the minimum number of synchronous generation units required online could be reduced further following the implementation of the synchronous condensers (including flywheels) and EnergyConnect where all key elements of the South Australian power system were intact.

Similar to the previous case, these planning assumptions did not assume that the new AC interconnector, combined with the four synchronous condensers, would address all of the requirements for system security in South Australia for the future under all circumstances.

It was assumed that additional measures would be required for outage conditions, protected events[17], or where AEMO declared abnormal operating conditions. Detailed studies, to be undertaken in parallel with commissioning of synchronous condensers and the implementation of EnergyConnect, will determine the operational requirements for managing the power system during outages, protected events, or abnormal operating conditions.

For the planning assumptions used in the modelling of the 2018 ISP, AEMO assumed the minimum requirements, including a reduction of synchronous generating units to zero, where both AC interconnectors were intact, there were no critical outages within the state, normal operating conditions prevailed, and additional measures were in place and effective to arrest and remediate any potential further declines in system strength (such as connecting generation and increasing metropolitan DER) from the current state (as of 2018).

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[17] AEMO. 2018 Power System Frequency Risk Review Final Report; June 2018: http://aemo.com.au/-/media/Files/Electricity/NEM/Planning_and_Forecasting/PSFRR/2018_Power_System_Frequency_Risk_Review-Final_Report.pdf