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AUSTRALIA

CREATING CLARITY

Essential System Service Modelling

A report prepared for the Energy Security Board

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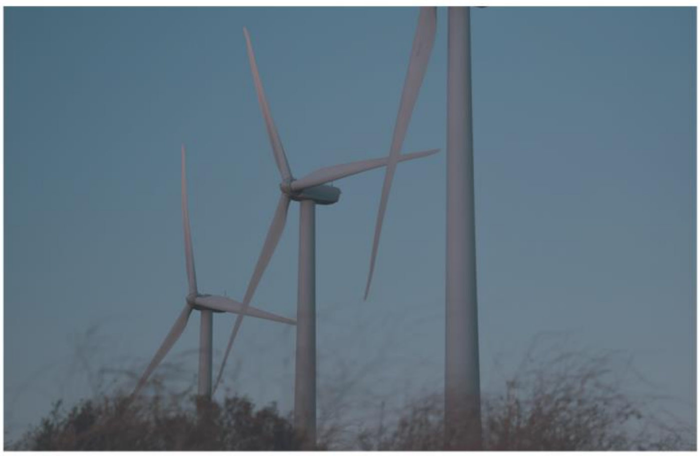

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1 Executive summary

Since 2017, system strength shortage has been a persistent challenge in the NEM as (grid-following) inverter-based resources (IBR) such as wind and solar continue to enter the market. This has caused connections delays as well as frequent AEMO interventions through a combination of directing on synchronous generators and curtailing IBR output.

To enhance the provision of system strength in the NEM, the Energy Security Board (ESB) has proposed to introduce reforms targeting both the investment and operational timeframes. These reform initiatives are currently being progressed by the AEMC's rule change processes.

- At the investment timeframe, the ESB proposed to introduce a structured procurement mechanism in which TNSPs will use a combination of network and non-network options to proactively deliver an efficient level of system strength.
- At the operational timeframe, as system strength does not have a real-time market, the ESB proposed new scheduling options such as the Unit Commitment for Security (UCS) and the System Security Mechanism (SSM) to schedule this service, potentially to an efficient level.

Cornwall Insight Australia is engaged by the ESB to assess the potential benefit of the proposed reform package for system strength provision. We model a Reform case where both investment and operational reforms are implemented and a No Reform case in which TNSPs are still constrained to maintain minimum system strength and all new IBR entrant are required to bring their own system strength remediation schemes.

The focus of our modelling is to quantify the saving in resource cost, including the cost of procuring system strength and the dispatch cost of the real-time energy market. To reflect the expected rapid transition in the coming years, following discussion with the ESB, we used the ISP 2020 Step Change scenario in our modelling exercise, which covers the period between financial year 2022/23 to 2039/40.

Due to the time constraint of our engagement, in this report we modelled a scenario with minimal commercial uptake of grid-forming inverters, and new system strength investment comes in the form of only synchronous condensers. These assumptions also reflect a conservative view of technological process that may help to address system strength shortages. These two impacts result in an upper bound on the estimated benefit of the reform. Cornwall Insight Australia is currently undertaking additional work to model a scenario with strong uptake of advanced inverters (including grid-forming inverters), which would represent a lower bound. The benefit of the reform package is likely to be significantly lower in this alternative scenario. The result of the additional modelling is expected to be available shortly.

Our current modelling found that the upper bound net benefit of the proposed reform package is approximately $1.2Bn in NPV over the modelling period (discounted at 5.9% as in the ISP Step Change scenario). This is achieved through the efficient procurement of system strength via a combination of network and non-network solutions.

The reform is estimated to lead to a capital cost upper bound saving of $2.1Bn in NPV (based annualised capex payment between FY22/23 and FY39/40). This is partly due to the economy of scale under TNSP procurement and the ability of IBR plants to share system strength solutions procured by TNSPs. The other important factor contributing to lower capital cost is TNSPs procuring an optimal level of system strength, which includes efficiently curtailing IBR output when their marginal value is less than the marginal cost of procuring additional system strength to host them.

The efficient utilisation of non-network options was also crucial to the reduction in capital expenditure and hence, the realisation of the overall reform benefit. In early years, the NEM still has an abundance of synchronous generators, which could be a cheap source of system strength if they can be effectively scheduled. In later years, new and existing pumped hydro units become an important non-network option for system strength supply. While greater utilisation of synchronous generation and storage assets led to an increase in operating cost ($0.9Bn over the reporting period), they allow TNSPs to defer investment in network options. The model therefore demonstrates the importance of an operational mechanism to schedule synchronous generation and storage assets so that they can be part of the efficient system strength supply mix.

2 Introduction

As part of its post-2025 market design project, the Energy Security Board (ESB) proposed to introduce a structured procurement mechanism for system strength in the NEM and an operational mechanism to schedule this service during dispatch, potentially to an efficient level. Cornwall Insight Australia was engaged by the ESB to undertake modelling to assess the potential benefit of its proposed reform package.

2.1 Background – system strength in the NEM

2.1.1 Overview of system strength

While the technical definition of system strength is complex, it fundamentally refers to the stability of voltage waveform[1]. Currently in large electricity systems, system strength is predominantly supplied by online synchronous generator and synchronous condensers (syncons), although new technologies such as grid forming inverters might also be able to supply system strength in the future. Inverter-based resources (IBR) such as solar, wind and battery with grid following inverters require system strength to operate stably and act as the source of demand for this service.

System strength is a locational product and a synchronous generator's contribution is provided in full and at a constant quantity provided regardless of its power output. These features make the service currently incompatible with a real-time market design[2], which is used to schedule and co-optimise energy and frequency control ancillary services (FCAS) in the NEM. As more renewable resources enter the NEM, their low operating cost puts downward pressure on pool prices and cause some synchronous generators to decommit (e.g., go offline) at times. Not having enough synchronous machines online could lead to a shortage of system strength in parts of the NEM. For example, South Australia has experienced ongoing system strength shortfall since 2017. More recently, renewable generators in western Victoria and North Queensland have also been adversely affected by system strength shortage.

2.1.2 The status quo arrangement to manage system strength

Currently AEMO manages system strength operationally through a combination of directing (and compensating) synchronous generators online and curtailing IBR output (e.g., wind and solar). At the investment timeframe, TNSPs have the obligation to procure system strength to fill the minimum system strength gap identified by AEMO. However, the complexity in forecasting often means that a minimum gap could not be identified with sufficient lead time for the TNSPs to address the shortfall before they become an operational issue.

Shortfall of system strength has also led to delays and uncertainties in the connection process for new IBR entrant. Under the current rules, new entrants are required to "do no harm" and undertake their own system service remediation action before they can connect to the grid. This has caused significant delays in parts of the NEM due to the complex the Full Impact Assessment (FIA) required in the connection process. In addition to the financial loss caused by the connection delays, the remediation actions could also add material cost to new projects. Commercial arrangements and the competitive nature of the market make it challenging for participants to reach agreements to share their system strength related assets, leading to potential duplication or over subscription of system strength solutions across participants.

2.2 The ESB's proposed reforms

As part of its post-2025 market reform project, the ESB has proposed several reform options to improve the provision of system strength at both the investment and operational timeframes.

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[1] *A more detailed explanation of system strength can be found in this AEMO document:* https://aemo.com.au/-/media/files/electricity/nem/system-strength-explained.pdf

[2] *ESB, Post 2025 Market Design Options – A paper for consultation Part A, p47.*

2.2.1 Investment timeframe – TNSP led system strength procurement

On 29 April 2021, the AEMC published its draft determination on the *Efficient management of system strength on the power system rule change*[3] proposed by Transgrid (called the *Transgrid RC* hereafter) and introduced reform on system strength procurement at the investment timeframe. On the supply side, the current minimum system strength framework will be replaced by a new arrangement where the TNSPs will proactively procure the service to meet some system strength standard specified by AEMO. The TNSPs can meet the standard through a portfolio of network (such as building syncons or other network assets) or non-network options (such as entering system service contracts with existing synchronous generators).

On the demand side, the current "do no harm" provision will be replaced by a System Strength Mitigation Requirement whereby new IBR entrants could elect to pay a system strength charge to use the services provided by the TNSPs. Under this option, the new entrant would not be required to undertake its own remediation actions and could avoid the time-consuming FIA in the connection process. In addition, new IBR entrants would also be required to meet some mandatory new access standards to manage their demand for system strength.

2.2.2 Operational timeframe – Scheduling mechanisms for system strength

While synchronous generation or storage assets could potentially be used to provide system strength, the lack of a real-time market for this service means these resources must be activated via some central instruction. As more system strength above the minimum level increases the IBR hosting capability in the system, activating more contracts could potentially reduce the overall system cost by supporting more VRE during operation. This points to the potential need of some optimisation-based mechanism to schedule system strength within the operational timeframe. Therefore, the ESB is considering two potential mechanisms, the Unit Commitment for Security (UCS) and the System Security Mechanism (SSM), which are also investigated by the AEMC's ongoing rule change processes[4].

The primary function of the UCS would be for an operational tool that allows AEMO to activate system service contracts (e.g., for system strength) procured by the TNSPs and schedule the related services (potentially) at an efficient level (e.g., increasing IBR hosting capacity where it is cost effective to do so). Participation in the UCS *scheduling mode* is restricted to resources that are under a system service contract with the TNSPs. The SSM would be a short-term procurement mechanism, which could provide an adaptable operational tool to complement planning-based solutions for system strength as well procuring other resources needed to maintain security. Contracts procured through the SSM would then be scheduled through the UCS. Currently it is expected that, as the NEM continues to transition, the UCS would be used to schedule contracts for other system services without a real-time market in addition to system strength (if additional system services are unbundled and created).

2.3 The rest of the report

The rest of the report will be organised as follows:

- Section 3 explains our modelling methodology and assumptions.
- Section 4 present the modelling results and the estimated benefit of the reform package.
- The Appendix section provides some more detailed information on the supply and demand of system strength modelling outcome for selected years.

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[3] *Full draft determination available at* https://www.aemc.gov.au/rule-changes/efficient-management-system-strength-power-system

[4] *The UCS is investigated in the Capacity commitment mechanism for system security and reliability services RCP at* https://www.aemc.gov.au/rule-changes/capacity-commitment-mechanism-system-security-and-reliability-services
The SSM is investigated in the Synchronous Services Markets RCP at https://www.aemc.gov.au/rule-changes/synchronous-services-markets

3 Methodology

3.1 Modelling scope and scenario

We will model a "Reform" and a "No Reform" case to estimate the benefit of the proposed system strength reforms at both investment and operational timeframes. The model will focus on the difference in resources cost between the two cases, including the cost of supplying system strength as well as its impact on the efficiency of energy market operation. The exercise will be carried out through a PLEXOS-based market dispatch model.

In practice, system strength is a locational service, and its detailed engineering requirement cannot be readily represented in a market dispatch model such as PLEXOS. While an iterative approach between a market dispatch model and an engineering model could capture more detailed engineering nature of system strength, such modelling would be very time consuming and beyond the scope of our engagement. Based on discussion with the ESB, we have designed a methodology to capture the main economic trade-offs of system strength provision, and these will be discussed in more detail in Section 3.2.

3.1.1 ISP scenario used in modelling

Based on discussion with the ESB, we have chosen the "Step Change" scenario from AEMO's 2020 ISP, including the associated cost inputs, transmission expansion and coal retirement paths, as the basis of our modelling. Compared to the "Central" scenario, the "Step Change" scenario has stronger uptake of renewable and earlier retirement of coal generators. Notably, more than half of the existing coal plant will close by FY27/28 in Victoria and by FY30/31 in NSW and Queensland. From FY36/37 onwards there will be no coal left in NSW and Victoria, and only 2000MW coal capacity will still be operating in Queensland by FY39/40. On the other hand, by FY39/40, more than 45 GW new wind and solar will enter the NEM relative to the FY21/22 level in the "Step Change" scenario. The more rapid transition in the "Step Change" scenario leads to faster reduction in existing system strength supply (from synchronous generators) and greater system strength demand (to host IBR capacity), which means system strength reforms will more likely be needed to help manage the transition.

Compared to the Central scenario, the Step Change scenario additionally includes the Tasmanian Renewable Energy Target (TRET) and two cables of Marinus Link (750 MW each from FY28/29 and FY31/32). In addition, we have included or updated the following government policies and major project commitments since the 2020 ISP:

- NSW government's electricity infrastructure roadmap to deliver close to 12 GW renewable and 2 GW storage capacity by 2030.
- The newly announced Tallawarra B (316 MW) and Kurri Kurri OCGT plant (660 MW), both assumed to start operation in NSW from FY23/24.
- Kidston pumped hydro to start in Feb 2025 and Snowy 2.0 in Dec 2026 based on AEMO's May 2021 Generation Information data

To account for the potential impact on the future generation outlook from the above recent development (such as the NSW roadmap), we will rerun long-term investment model in PLEXOS but hold other Step Change scenario inputs and paths (including transmission expansion and retirement) constant. This will be discussed further in Section 3.3.

3.1.2 The "No Reform" case

The "No Reform" scenario will assume the status quo arrangements for system strength remain at both the investment and operational timeframes. Therefore, TNSPs will only supply minimum system strength gap and individual IBR entrants must bring their own remediation measures. In practice, this would likely mean that connection delay could persist, and there is no operational mechanism to schedule resources to supply system strength other than AEMO's direction for minimum system strength and operational curtailment of IBR. Without reform at both investment and operational timeframes, TNSPs might continue to face significant difficulties in reaching agreements with synchronous generators or storage assets for system strength supply[5]. In our model, we assume TNSPs cannot utilise synchronous generators or storage to provide system strength in the No Reform case due to difficulties in contracting. This is likely to overstate the benefits. Further modelling details of the No Reform case can be found in Section 3.3.

3.1.3 The Reform case

The Reform case will assume both the TNSP-led procurement and some form of dispatch mechanism will be implemented so that:

- TNSP will procure system strength using both network and non-network options to an efficient level.
- New IBR entrant will not experience system strength related connection delays.
- There will be a dispatch mechanism that efficiently schedule all available assets (including network options, contracted and uncontracted synchronous generation and storage assets) to provide system strength at the operational timeframe.

Importantly, an "efficient level" of system strength does not mean there will be no IBR output curtailment due to system strength shortage (i.e., completely "building out" system strength). The model could choose to curtail some IBR if the curtailment cost is lower than the cost of procuring additional system strength.

Based on discussion with the ESB, we have chosen to model and quantify the benefit of both investment-timeframe and dispatch-timeframe reforms together. This is because the two reforms are complementary to each other. For example, if non-network options, such as using existing synchronous generators or storage, are part of the system strength supply mix procured by the TNSP, some dispatch mechanism (such as the UCS and SSM) is needed to schedule these synchronous resources. This is particularly important in assessing whether additional system strength should be provided by synchronous generator or storage to host more IBR given the short-term market outlook. In the absence of such dispatch mechanism (other than AEMO's direction), supplying system strength from existing synchronous assets would be less effective, and TNSPs will be constrained to rely more on network options, which could reduce the overall efficiency of system strength provision.

The modelling also does not seek to model the UCS and the SSM separately. In practice, so far as system strength scheduling is concerned, the main difference between the two mechanism is the former allows only contracted synchronous resources to participate and the later includes uncontracted resources as well. While the model would "use" a synchronous generator or storage to provide system strength to lower overall system cost, it does not differentiate whether this resource activated under the system service contract or not. In theory, if such contracts could be infinitely flexible, all synchronous resources "used" by the model to supply system strength would be contracted, which means there would be no need for SSM for system strength. On the other hand, if it were very difficult to enter into long-term system service contracts, so that very few resources could participate in the UCS, then SSM would likely provide large additional value by allowing more synchronous generators to be scheduled "on the day" when it is cost effective to do so.

In effect, the model captures theoretically the maximum benefit that could be achieved under a *package of reforms* that target the efficient provision of system strength in both investment and operational timeframe.

3.1.4 Modelling horizon

The modelling and report horizon will be from FY22/23 to FY39/40 inclusive, as FY22/23 is the earliest time some elements of the reform could be implemented. The resource costs will be discounted at 5.9%, which is the discount rate used in the ISP Step Change scenario.

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[5] To date, the main exception seems to be Powerlink and TasNetworks' agreement with hydro units in Queensland and Tasmania to supply system strength, whereas no such arrangement could be made in South Australia despite the chronical system strength shortage in the region. We note, however, that the Queensland and Tasmania hydro assets are owned by state governments.

3.2 Modelling system strength in a market-dispatch model

As PLEXOS is a market-dispatch model, it cannot capture the detailed engineering aspect of system strength. In addition, there is limited data on future system strength requirements and emerging technologies such as grid-forming inverters, which further hampers accurate detailed representation of this service out to 2040. As a result, we have to make some simplifying assumptions when representing system strength in the model while still endeavouring to capture the main economic trade-offs of the reform. We will first outline our principles of making these assumptions and then discuss each assumption in turn.

3.2.1 Principles of making assumptions regarding system strength in our model

We will apply the following principles in making our assumptions:

- **Capturing the main trade-off:** An assumption is made for the purpose of allowing us to capture the main economic trade-off involved in the reform.
- **Benchmarking and extrapolating from known data:** The starting point of our assumptions are AEMO's data or information from public data or report.
- **Aiming for simplicity:** If the existing assumptions have already captured the main trade-offs, we do not increase the amount of "guessing" to increase the complexity or granularity of the model.
- **Acknowledging and discussion the limitation:** Despite our best efforts, some features of system strength cannot be incorporated in the model due to the lack of data, the limitations of a market-dispatch model or being outside scope/time limitation of the exercise. If some features are left out in our modelling, we will acknowledge them (to the extent we are aware) and discuss their limitations in Section 4.4.

3.2.2 Supply and demand of system strength

In our model, we will use fault capability (measured in MVA) as a proxy for system strength. This is also the measurement used by the AEMC in its draft determination for the Transgrid RC.

Traditionally system strength is supplied by synchronous generators and syncons when they turn on. Recently there has been development in new technologies such as grid-forming inverters, which could allow IBR plant such as wind, solar and battery plant to supply system strength as well. While new technologies such as grid-forming inverters could be adopted in the future, currently there is still large amount of uncertainty around their cost and timing of widespread commercial uptake. Due to time constraint, in this report, we will assume only synchronous generation and storage assets and syncons can supply system strength. Innovation, technology development over time and the fact that different solutions can be utilised will mean that this is a conservative approach. This means that the results represent an upper bound on the benefits that could occur. We are undertaking additional analysis to model a scenario with widespread uptake of grid-forming inverters, and the result is expected to be available shortly. We will discuss the limitation of our current assumption in Section 4.4.1. For the current modelling, this means that:

- In the Reform case, TNSPs can build syncons (network options) or use existing synchronous generation or storage assets (non-network solutions) to supply system strength.
- In the No Reform case, each new IBR entrant will bring their own syncons. The size of the syncon in MVA fault level is assumed to be 3 times the nameplate capacity of the IBR plant in MW.[6] (See requirement for hosting additional IBR in Section 3.2.3.) This is a simplified and conservative view of the amount of system strength services required by inverter-based generation to connect and

[6] In practice, syncons come in fixed size and new IBR entrant would need to build the smallest syncon whose MVA fault capability is greater than 3 times of their name plate capacity. For example, if syncons come at 200 MVA increment, a 120 MW IBR entrant would have to build a 400 MVA syncon. As PLEXOS models IBR investment in 1MW increment, adopting the alternative "blocky" syncon assumption for new IBR entrants would make No Reform case more costly, especially for smaller projects, as it forces them to oversubscribe in the accompanying syncon.

operate stably out to 2040, given the potential technological innovation over that time horizon.

Based on discussion with the ESB, we adopt a uniform assumption that the fault capability (in MVA) supplied by synchronous machines when they turn on is 4 times their nameplate capacity. That is, an online 500 MW synchronous unit (regardless of its type such as coal, gas, hydro, or pumped hydro) will supply 2000 MVA fault capability and an online 125 MVAr syncon will supply 500 MVA. The exception is pumped hydro in pumping mode. Based on feedback from the ESB, we assumed its system strength supply in pumping mode is discounted to 70% relative to when in generating mode. (That is, a 100 MW pumped hydro unit supplies 400 MVA fault capability when generating, but only 280 MVA when pumping). In addition, we have excluded synchronous plant with large number of small individual units from system strength supply (such as Port Stanvac and Lonsdale).

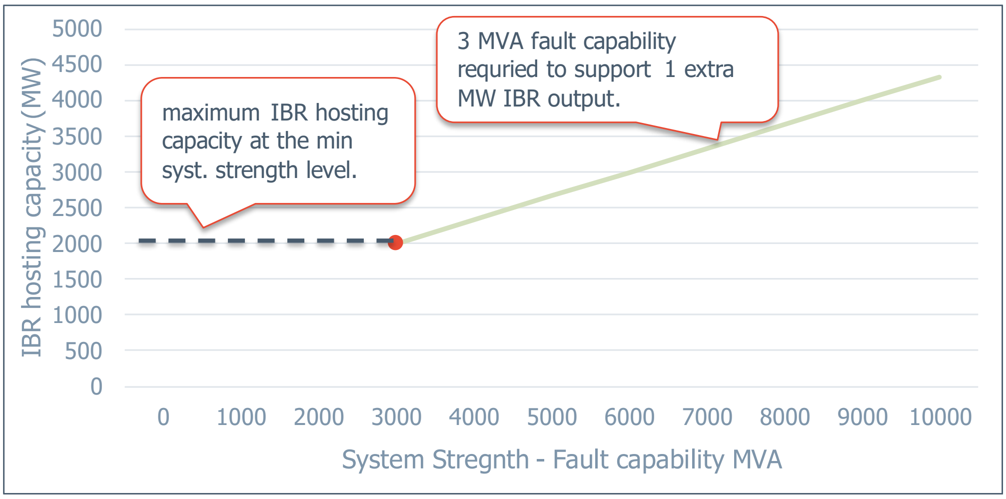
As our current modelling does not include grid-forming inverters, we assume all wind, solar and grid connected batteries consume system strength. A more detailed account of how the model balances demand and supply of system strength is explained in Section 3.2.3.

3.2.3 Minimum system strength and additional IBR output hosting capacity

For each location, a minimum level of system strength as measured in fault capability is needed. At this minimum level, AEMO might curtail IBR output (in MW) as well to ensure the system is secure. The hosting capacity of IBR will be increased if additional system strength is supplied beyond the minimum level. After discussion with the ESB, we have assumed that 3 MVA fault capability is needed to support an additional 1 MW IBR output at each location. We note this is a conservative estimate of system strength required to host additional IBR and the figure would likely be much lower with greater uptake of more advanced inverters, including grid forming inverters. This alternative scenario reflecting stronger uptake of advanced inverters would model a lower MVA to MW ratio assumption.

Figure 1 provides a graphical representation of our modelling approach of minimum system strength and additional IBR hosting capacity. The model is required to ensure there is enough resources online at all times to meet the minimum system strength requirement (e.g., 3000 MVA in figure). However, if the model wants to increase IBR output beyond the associated hosting capacity (e.g., 2000 MW in figure) at minimum system strength, it must bring on additional resources to provide more system strength (through investment in new network assets such as syncons or activating more synchronous generators or pumped hydro), which would increase the cost of providing this service. Alternatively, the model could choose to curtail IBR without supplying more system strength if it is cheaper from a system-wide cost perspective.

Figure 1 Representing minimum system strength and additional IBR hosting capacity



Source: Cornwall Insight

3.2.4 Regional approach to model system strength

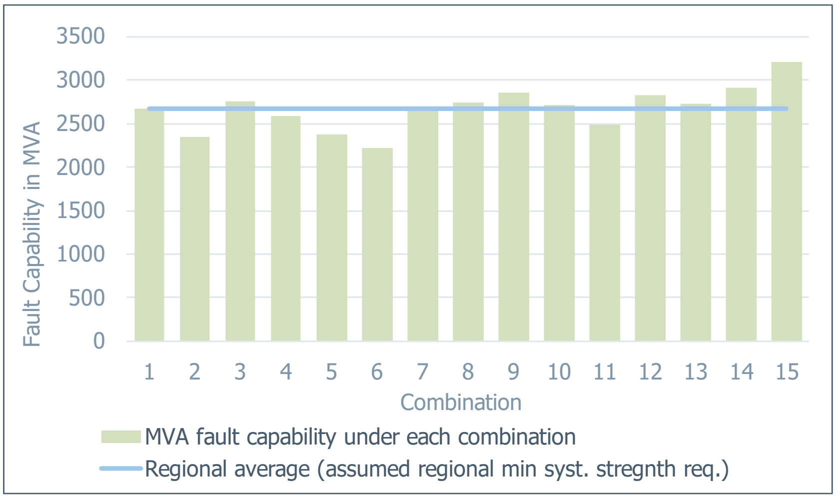
In practice system strength is a locational requirement. System strength supplied at one location might be heavily discounted as it travels across the network to a distant location. AEMO publishes varying minimum system strength requirements at several fault level nodes (which will be replaced by system strength node if the Transgrid RC is implemented) within each NEM region. However, modelling the sub-regional locational characteristics in a market-dispatch model like PLEXOS is very challenging due to the following reasons:

- It is impractical to model the physical aspects of system strength in PLEXOS to replicate AEMO's engineering modelling approach.[7] Consequently, the PLEXOS-based model could not accurately measure how much system strength supplied from location A would contribute to the requirement in location B based on the "real-time" dispatch outcome.
- While AEMO publishes minimum fault level requirements at different locations, it does not specify the associated IBR hosting capacity. As of May 2021, the only available IBR hosting capacity data at minimum system strength is for the whole South Australian region between 1900 and 2000 MW.[8]

Due to the limitation above, we have discussed with the ESB and agreed to undertake system strength modelling at regional level. This means each region will have a single minimum system strength requirement, and a single IBR hosting capacity that depends solely on total system strength supplied in the region. All synchronous generators and syncons will supply their full system strength capability only to the region in which they are located. A more detailed discussion on the limitation of our regional modelling approach can be found in Section 4.4.2.

We have designed a benchmark approach to estimate regional minimum system strength requirement based on public data available from AEMO. For each region (except Tasmania), AEMO publishes combinations (to various levels of detail) of synchronous machines that could provide minimum system strength. We use the benchmark fault contribution from synchronous machines discussed in Section 3.2.1 to work out the implied regional fault capability under each combination. We then take an average over all combinations in a region, which is assumed to be the regional minimum system strength requirement. The effect of this averaging approach for South Australia is shown in Figure 2.

Figure 2 Illustration of assumed SA minimum system strength req.



Source: Cornwall Insight analysis of AEMO data

[7] *More details can be found in AEMO's publications such as the "2020 System Strength and Inertia Report" and "System Strength Requirement Methodology".*

[8] *AEMO, Transfer Limit Advice – System Strength in SA and Victoria, April 2021.*

The combinations are chosen for each region as follows:

- For South Australia and Victoria, AEMO publishes detailed combinations of online synchronous generators and syncons (15 combinations for SA system normal conditions with 2 online syncons and 30+ combinations in Victoria as of April 2021[9]). This leads to a minimum requirement of 2673 MVA and 9411 MVA for SA and Victoria respectively.
- For NSW, AEMO requires seven large synchronous units to provide minimum system strength[10] but does not specify what constitute "large synchronous units". We assume they are equivalent to coal units ranging between 500 – 660 MW per unit. This leads to a minimum requirement of 15,920 MVA for NSW. (If we were to assume large gas or hydro units also quality, the minimum requirement for NSW would be halved leading to less system strength investment.)
- For Queensland, we calculate its minimum requirement based on AEMO's base case for its electromagnetic transient study, which consists of 7 CQ coal and 2 NQ hydro units.[11] This leads to a minimum requirement of 9553 MVA for Queensland.
- For Tasmania, AEMO does not publish detailed combinations. We assume its regional minimum requirement is 1450 MVA, which is the requirement at the George Town node.

We also need make assumptions on the associated IBR hosting capacity in each region when it is at the minimum system strength level, as no such information is available from AEMO except for South Australia, which is between 1900 – 2000 MW. To do this, we looked at historical semi-scheduled output in each NEM region in 2020 and found that the maximum 30-min regional semi-scheduled output was approximately 1500 – 2000 MW in each mainland region, and about 400 MW in Tasmania. As most NEM regions have recently experienced system strength related curtailment, it is reasonable to expect that their operational IBR hosing capacity is close to their limit at minimum system strength. Therefore, based on our principles of making less additional assumptions, we assume the IBR hosting capacity at minimum system strength is 2000 MW in each mainland region and 500 MW in Tasmania.

A summary of regional minimum system strength requirements in our study is provided in Table 1 below.

Table 1 Summary of regional minimum system strength requirement

Region	Approach	Min fault capability in MVA	IBR hosting capacity (MW) at min syst. strength
VIC	Average MVA from 34 combo. in AEMO's transfer limit table	9,411	2000
SA	Average MVA from 15 combo. in AEMO's transfer limit table including two syncons	2,673	2000
NSW	MVA from seven "large sync. gens", assumed to be 500 – 660 MW size.	15,920	2000
QLD	Average of combinations with "7 CQ coal + 2 NQ hydro units".	9,553	2000
TAS	Fault capability at George Town node above min of	1450	500

[9] *AEMO, Transfer Limit Advice – System Strength in SA and Victoria, April 2021.*

[10] *AEMO, 2020 System Strength and Inertia Report, p78.*

[11] *AEMO, 2020 System Strength and Inertia Report, pp81-82.*

1450 MVA.

Source: Cornwall Insight analysis of AEMO data

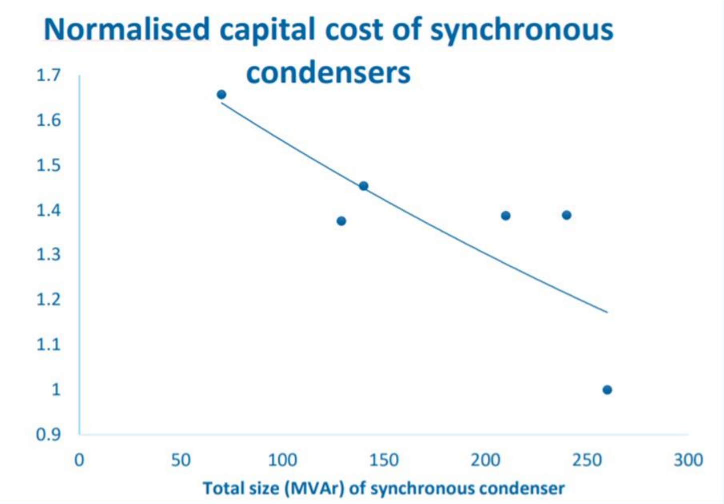
3.2.5 Syncon cost and parameters used in modelling

In the Reform case we assume TNSPs can build syncons from 200 MVA to 1000 MVA fault capability with 200 MVA size increment. As the per unit ($/MVA) cost will decrease for larger syncons due to economy of scale, we have used a benchmark approach to estimate the cost of syncons of various sizes as described below.

In 2019 the AER approved ElectraNet's proposal to build four 575 MVA syncons to supply system strength in South Australia. The upfront capital cost of each syncon is approximately 46.3 million.[12] The relative cost of syncons of different sizes (in MVAr) can be inferred from a recent study published by GHD[13] as shown in Figure 3. Using GHD's cost trajectory, we can extrapolate syncon costs from 200 MVA to 1000 MVA based on from the cost of SA syncons, as shown in Figure 4.

Our model also accounts for the auxiliary load consumption of syncons, which is inferred from the same GHD report.[14] As a result, we assume the auxiliary power consumption of a 200 MVA syncon is 1.5 MW. For simplicity we assume the auxiliary load increases linearly with the syncon size, so that a 1000 MVA syncon incurs an auxiliary load of 7.5 MW in our model. In the Reform scenario, we assume the syncons are always online so that their auxiliary consumptions are added as a flat load to the operational demand profile.

Figure 3 Normalised syncon capital cost



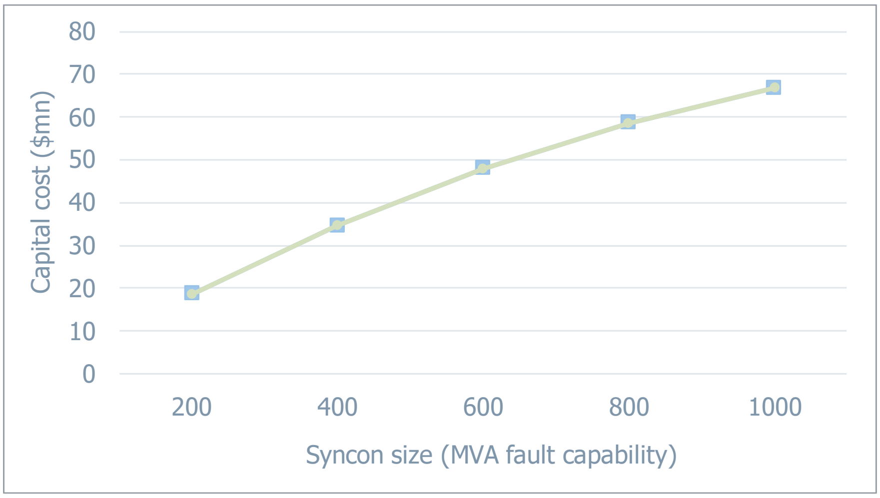
Source: GHD, Managing system strength during the transition to renewables, p39

[12] *AER, Final Decision ElectraNet Contingent Project, Main Grid System Strength, p21.*

[13] *GHD, Managing system strength during the transition to renewables, p39.*

[14] *GHD, Managing system strength during the transition to renewables, pp41-42.*

Figure 4 Capital cost for syncons of different sizes



Source: Cornwall Insight analysis based on SA syncon costs and GHD report

In the No Reform case, we assume individual new IBR entrants bring their own syncon whose MVA fault capability is three times of their nameplate capacity in MW (See discussion and footnote 6 in Section 3.2.2). As PLEXOS does not use fixed IBR entrant sizes but model their investment by 1MW increment, we will assume a representative $/MVA syncon cost to be applied uniformly to all syncons in the No Reform case for simplicity. As most new IBR entrant are below 200 MW in the NEM, we benchmark this on the 600 MVA syncon (see Figure 4) so the per unit capital cost of syncon is $0.08m/MVA in the No Reform case. We assume the syncons will be turned on when the associated IBR plant is running and have increased its auxiliary loss accordingly. To the extent that most new IBR projects will be less than 200 MW, our syncon cost and the "no-oversubscribe" assumptions in the No Reform case will tend to underestimate its cost.

3.3 Modelling design – integration with the energy model

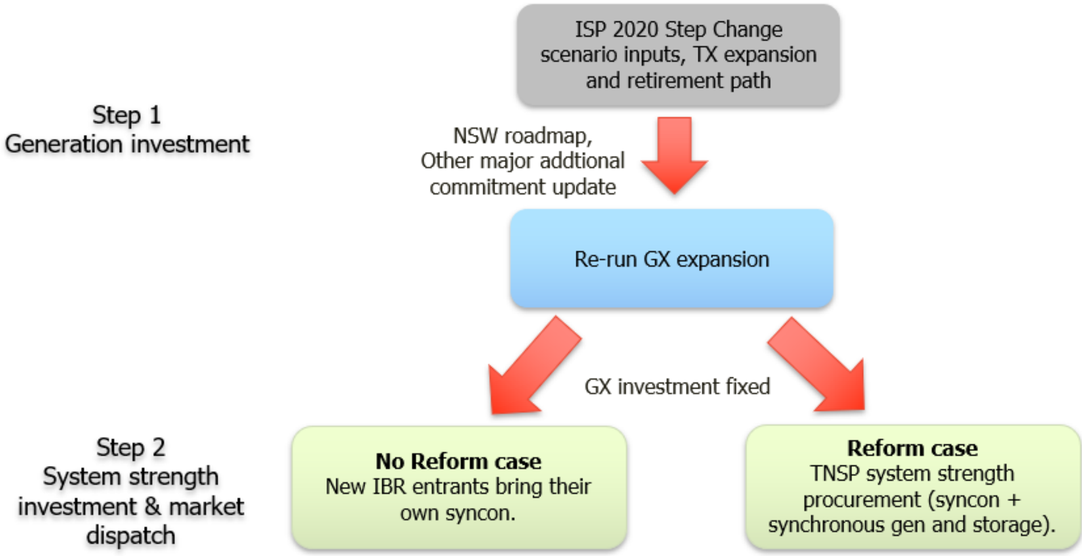
The modelling will be carried out via the following steps as illustrated in Figure 5. The first step involves rerunning the generation expansion model in PLEXOS by using the 2020 ISP Step Change scenario including its demand forecast, cost inputs, transmission expansion path and generation retirement path. The generation expansion model is rerun to account for the impact on future investment due to NSW infrastructure roadmap and other updated project commitment (such as Tallawarra B and Kurri Kurri OCGT).

The generation investment is then fixed and used in modelling both the Reform and No Reform cases which determines system strength investment and detailed market dispatch outcomes. This step will also work out the difference in system strength investment and market dispatch related cost between the Reform and No Reform cases, allowing us to assess the benefit of the reform package. As the inclusion of system strength constraints increases the computational complexity, this step is carried out at 3-hourly granularity (i.e., a year would have 2920 intervals) for both the Reform and No Reform cases.

- In the No Reform case, system strength investment, which consists of new IBR entrants building their own syncons, is done as a post-modelling calculation based on the investment outcome from the previous step, using the methodology discussed in Section 3.2.5. The dispatch modelling is run assuming there would be no operational system strength shortfall or related IBR curtailment. This assumption is likely to underestimate the cost of the No Reform case, as discussed in Section 4.4.3.
- In the Reform case, PLEXOS is reconfigured to include the system strength representation as discussed in Section 3.2.2 to Section 3.2.5 so that it will find the optimal system strength investment portfolio (building syncons and utilising existing synchronous resources) to deliver the efficient outcome. That is, minimising the total cost of procuring system strength and meeting energy demand. This includes allowing the model to curtail IBR output when its cost is less than the cost of

procuring additional system strength.

Figure 5 Steps of modelling



Source: Cornwall Insight

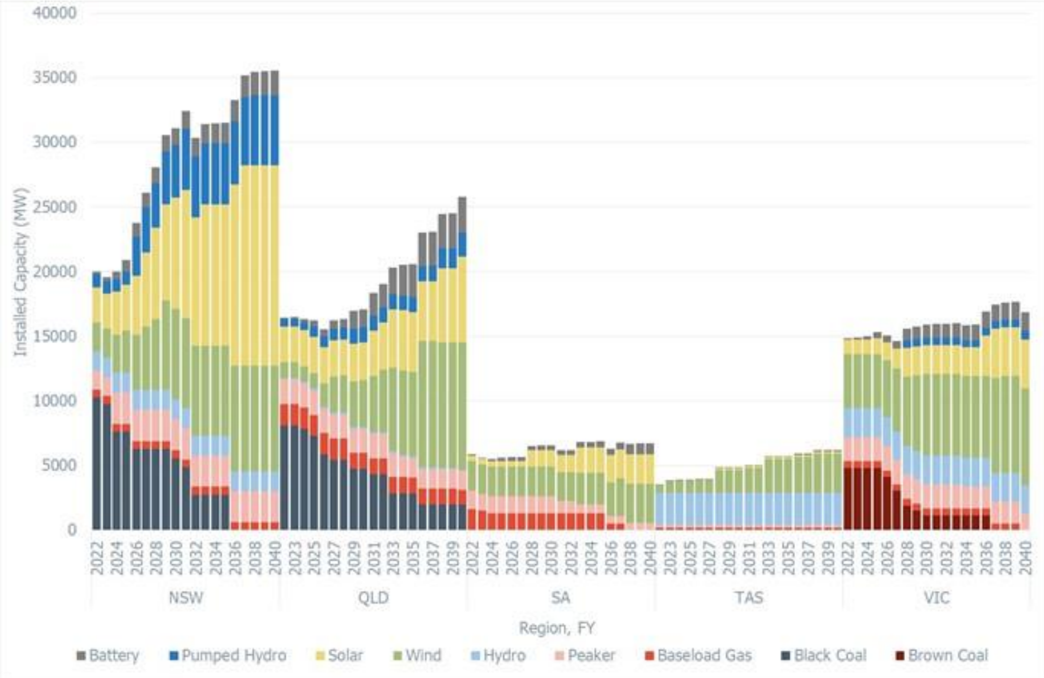
As discussed in Section 3.1.3, in the Reform case we model both investment and operational system strength related reforms as a package, and this is reflected in the co-optimised design of the second step for this case. In the Reform case, the model solves simultaneously the level of syncon investment, the utilisation of synchronous generator and storage, and if necessary, curtailment of IBR output to provide efficient system strength to minimise the total system cost. This effectively reflects the implementation of the reform package where TNSPs can procure system strength via both network and non-network options with the expectation that synchronous resources procured in the latter option will be scheduled efficiently via an operational mechanism (such as the UCS or the SSM). Our model, however, does not co-optimise generation and system strength investment decisions, this is discussed further in Section 4.4.4.

4 Results

4.1 Long-term generation outlook

As discussed in Section 3.1, we rerun the ISP Step Change scenario (using the same retirement and transmission expansion path) by including major new commitment (e.g., NSW Electricity Infrastructure Roadmap and the new gas plants in NSW) after the publication of the 2020 ISP. The resulting long-term capacity mix is shown in Figure 6, which is similar to that predicted in the ISP Step Change scenario. The ~12 GW VRE and ~2GW pumped storage to be constructed under the NSW Roadmap by 2030 (compared to less than 5 GW VRE in ISP Step Change) led to slightly less VRE investment in other NEM regions.

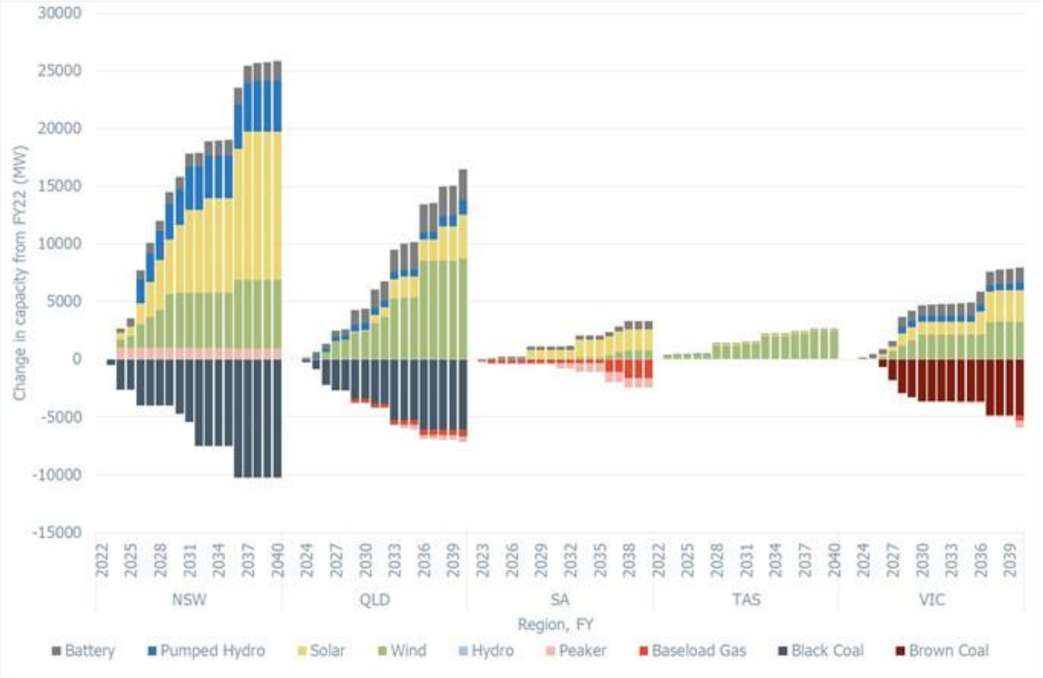
Figure 6 Long term capacity mix by technology



Source: Cornwall Insight

Figure 7 shows the change in capacity mix relative to the FY21/22 level. Compared to the Central scenario, the Step Change scenario sees stronger adoption of wind and solar together with faster retirement of coal. By FY39/40 there will be more than 40 GW new grid connected VRE capacity relative to the FY21/22 level. After around FY29/30, less than half of baseload coal and gas will remain in NSW, Queensland and Victoria and there will be no coal left in NSW after FY2034/35 and Victoria after FY2035/36. The increase in system strength demand from VRE and the reduction of its supply from existing synchronous generators result in the need to procure additional system strength during the transition.

Figure 7 Change in installed capacity relative to FY22



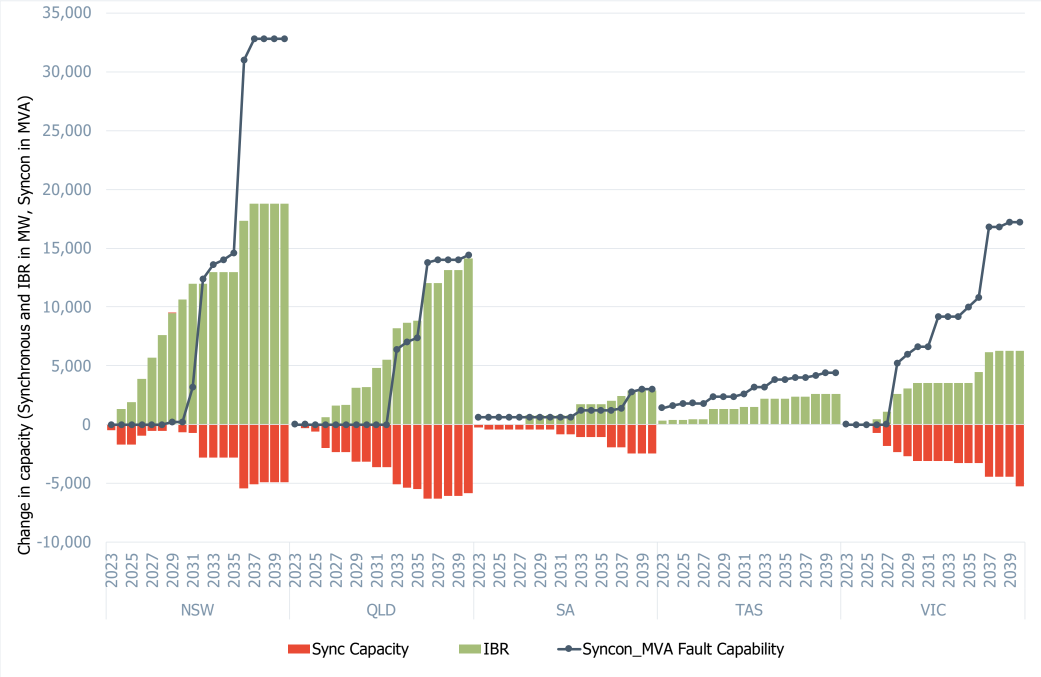
Source: Cornwall Insight

4.2 System strength procurement in the Reform case

4.2.1 Syncon investment path

In the Reform case, the TSNPs will procure system strength via a combination of network options (assumed to be building syncons) and non-network options (assumed to be utilising existing synchronous generators and storage). Figure 8 shows the system strength investment path (in terms of MVA fault capability from syncons) in the Reform case. Note for South Australia it excludes the 4 x 575 MVA syncons already purchased by ElectraNet. It also plots the changes in IBR and synchronous capacity (which includes the reduction in coal and gas and the increase in pumped hydro) to illustrate the change in supply and demand in system strength from grid connected generation resources.

Figure 8 system strength investment vs change in synchronous and IBR capacity



Source: Cornwall Insight

A notable result is that the syncon investment path is a function of both synchronous capacity retirement and IBR entry. However, large-scale syncon investment is not needed in large NEM regions such as NSW, Queensland, and Victoria until late 2020s or early 2030s as there is still enough large coal units that can provide system strength in early years. However, once the reduction in synchronous resources reaches a certain threshold, syncon investment ramps up quickly with further synchronous retirement. We note the amount of syncon investment is large in later years due to the current modelling assumption of no grid-forming inverters and the conservative SCR ratio of 3. We expect syncon investment would be substantially lower (in both the reform and no reform cases) in a scenario with large uptake of more advanced inverters, including grid-forming inverters.

When there is an abundance of synchronous capacity, especially coal units in the market, they are a cheap alternative to syncons for supplying system strength (e.g., the cost of keeping an already running coal unit online might be low). In addition, with more coal units in the market, they tend to lower the pool prices and therefore the value of hosting additional VRE output. This has resulted in low level of syncon investment before the end of 2020s for NSW, Queensland, and Victoria. The reverse happens when there are less coal units in the market after 2030. It would be a lot more expensive to run gas units frequently to supply system strength, and the additional IBR hosting capacity becomes more valuable as pool prices is more likely to be high when VRE are curtailed. In response, syncon investment ramped up rapidly in later years. A more detailed illustration of system strength supply and demand for all intervals modelled is provided for NSW and for selected years in the Appendix Section 5.1.

We would like to note that, while the model demonstrates the importance of utilising synchronous generators and storage as part of the system strength procurement portfolio, a few assumptions have also contributed to the low syncon build level in early years:

- Modelling system strength at regional level overstates the contribution by coal generators in areas remote from synchronous generation centres. One would expect a few more syncons to be installed earlier in some remote areas in NSW, Queensland and Victoria compared to our modelled result. This is discussed further in Section 4.4.2.
- As with many optimisation-based algorithm, our model finds the “just right” amount of system strength to minimise total system cost while maintaining system security. In practice, one would

expect the TNSPs and AEMO to plan for more contingency and outage scenarios and procure additional buffer for the system. For prudence measures, TNSPs might also procure syncons earlier and install them in a more staged manner compared to the rapid ramp up in later years in our model.

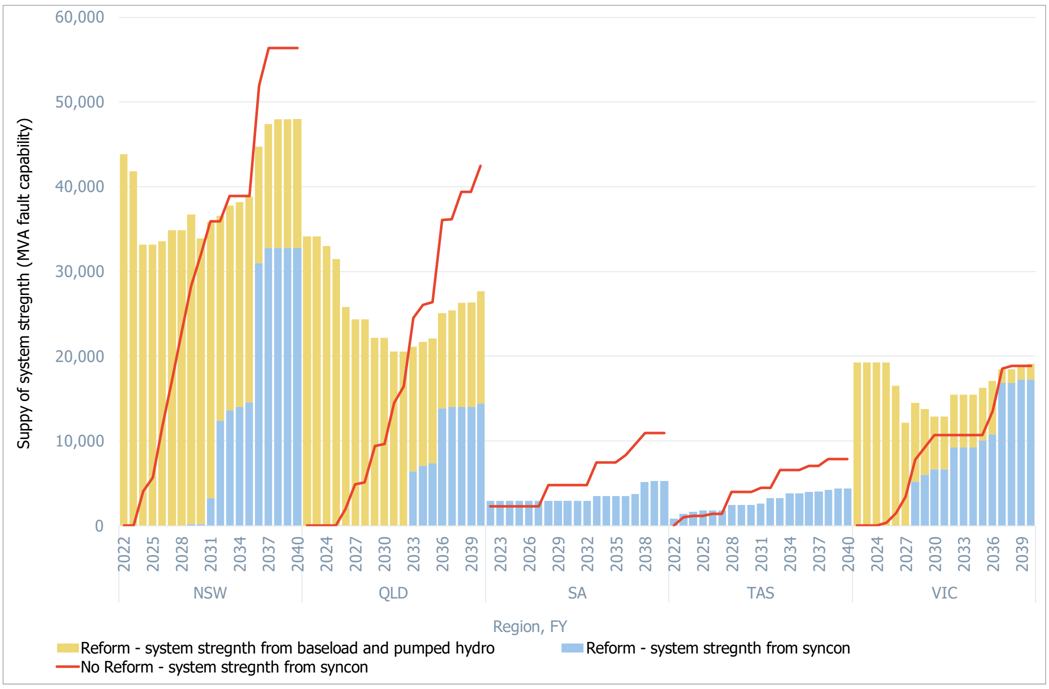
4.2.2 Efficient provisions of system strength

In later years, with nearly all coal units exiting the market (except for approx. 2000 MW in Queensland), our model still builds much less syncon in the Reform case compared to the No Reform case. As discussed in Section 3.2.5, in the No Reform case, new IBR entrants are assumed to build their own syncon to offset their own system strength demand, so that the MVA fault capability from their syncon is equal to three times of their nameplate capacity. The difference is due to a few factors:

- There are still some remaining gas and hydro units, and new pumped storage units are invested in later years, which can be utilised as non-network solutions for system strength provision.
- Not all IBR resources' output peak at the same time, which means the syncons built by the TNSP can be shared by multiple IBR resources.
- The model chooses to efficiently curtail IBR output when the value of additional IBR is less than the cost of supplying more system.

A comparison between the total system strength procured in both cases is shown in Figure 9. For the Reform case, we have included system strength that can be supplied from synchronous baseload and pumped hydro units and from TNSP built syncons. (In addition, TNSPs can also procure system strength from gas and hydro units in the reform case although they are not shown in the chart due to the high cost or potentially limited energy supply). In the No Reform case, contracting with synchronous generators and storage units is assumed to be not possible. The comparison demonstrates the potential of system strength supply that could be unlocked from effectively utilising existing synchronous generators and storage assets.

Figure 9 Syncon build comparison - Reform vs No Reform

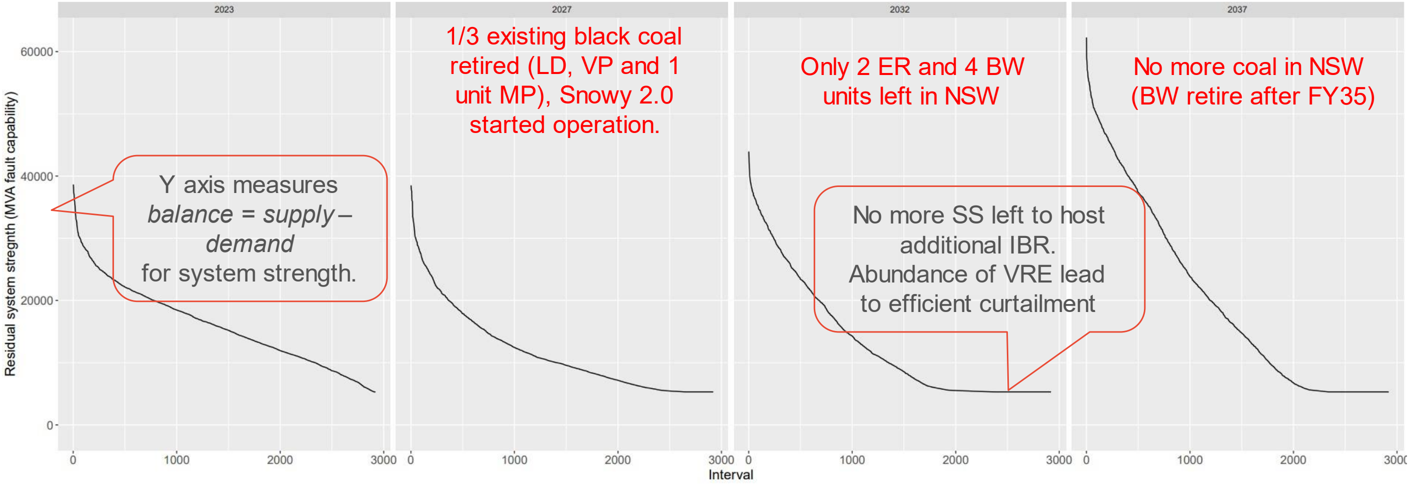


Source: Cornwall Insight

In the future the system costs (system strength being one of them) incurred to host IBR could be high, despite their near-zero cost for electricity generation. Occasionally the high system cost could lead to efficient curtailment of VRE, and it could be cheaper to utilise other resources such as hydro, pumped hydro or occasionally gas as backup during these times. In the rest of this section, we provide some more detail on the efficient curtailment of IBR in our model.

Figure 10 shows the "duration curve" of remaining system strength for hosting additional IBR in NSW for selected modelled years. This is calculated by subtracting system strength "consumed" by IBR generation from total system strength supplied at each interval, adjusting for the minimum regional system strength requirement. The years were chosen to mark different points along the transition path where coal units are replaced by IBR entrants. When the curve drops to 0 on the Y axis, the model has used up all online system strength and cannot host additional IBR, leading to its curtailment. It can be seen in later years (FY31/32 and FY36/37), such efficient curtailment happens for approximately 20-25% of the time.

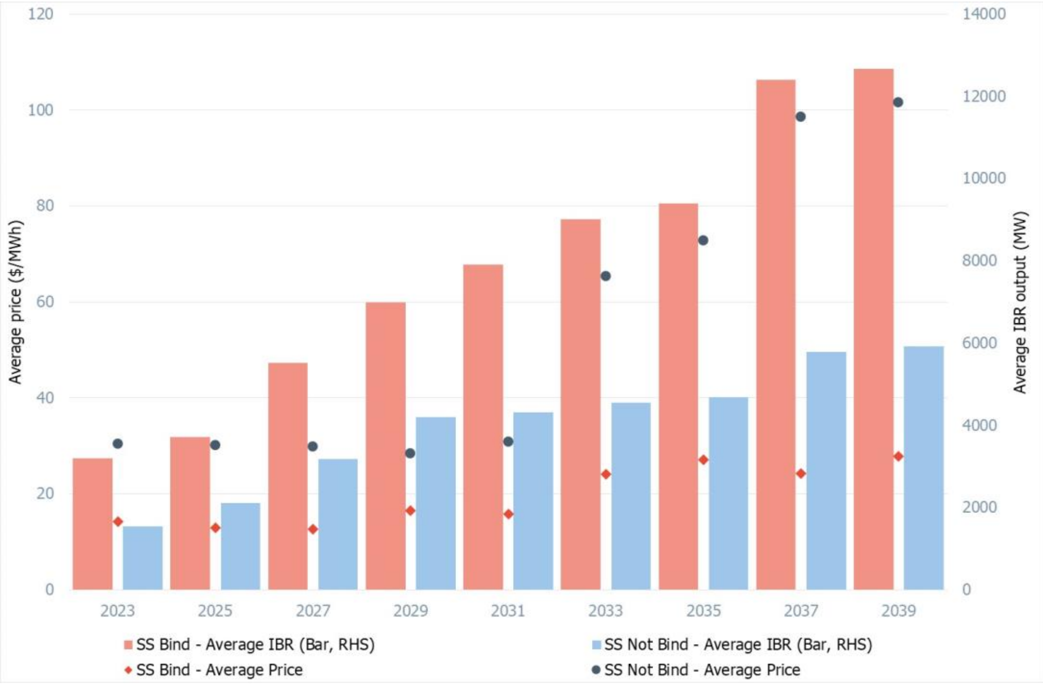
Figure 10 Remaining system strength for hosting IBR - NSW selected years



Source: Cornwall Insight

Figure 11 provides a comparison of average IBR output and pool prices depending on whether system strength related curtailment is in place for selected years in NSW. The dots measure average energy prices and bars measure average IBR output (RHS). Red coloured series represent when system strength bind (IBR curtailed) and blue series are when it does not. As can be seen in the chart, when IBR are curtailed due to system strength in the model, its average output is higher (more than double when system strength does not bind), leading to lower average pool prices ($15-30/MWh vs $30-100/MWh).

Figure 11 Energy prices when IBR efficiently curtailed – NSW selected years



Source: Cornwall Insight

4.3 Cost assessment

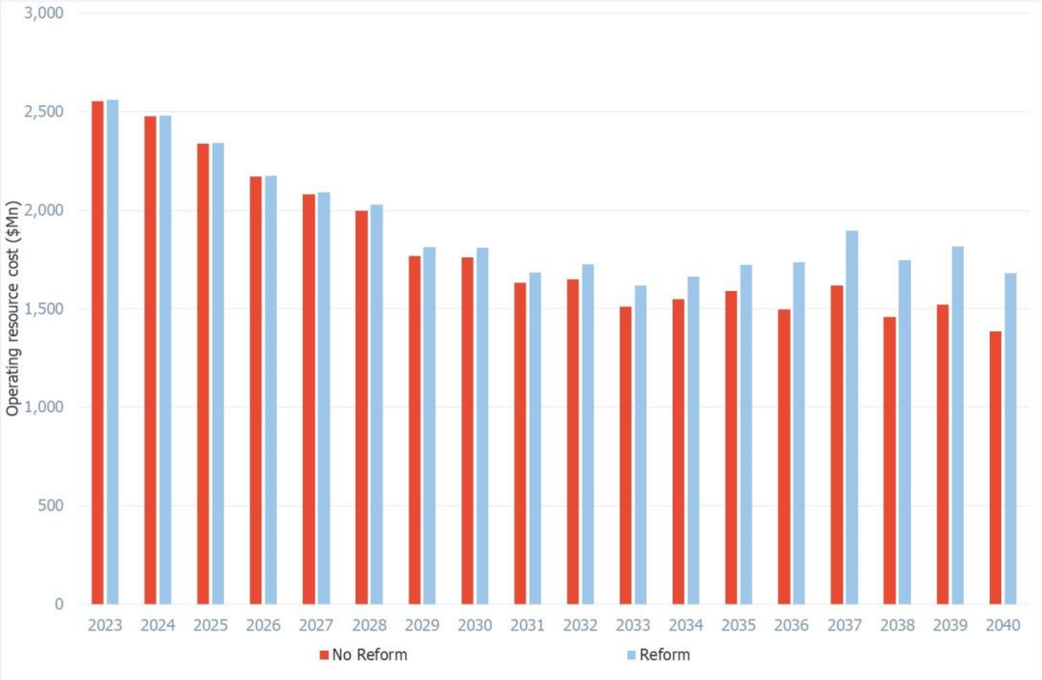
Over the period between FY22/23 to FY39/40, the reform package is estimated to deliver an upper bound net benefit of $1.2Bn in NPV terms (discounted to FY21/22 at 5.9%). This is achieved through efficiently procuring system strength via a combination of network and non-network solutions. The reform will lead to an upper bound capital cost saving of $2.1Bn in NPV (based annualised capex payment between FY22/23 and FY39/40), as the TNSPs' expenditure on network options is less than the total individual system strength remediation cost by IBR entrants. In addition to the economy of scale and asset sharing under TNSP procurement, non-network options are also crucial to the reduction in capital expenditure. While greater utilisation of synchronous generation and storage lead to an increase in operating cost ($0.9Bn over the reporting period), they allow TNSPs to defer investment in network options. Figure 12 provides a cost breakdown by year.

Figure 12 Overall cost difference by year

Source: Cornwall Insight

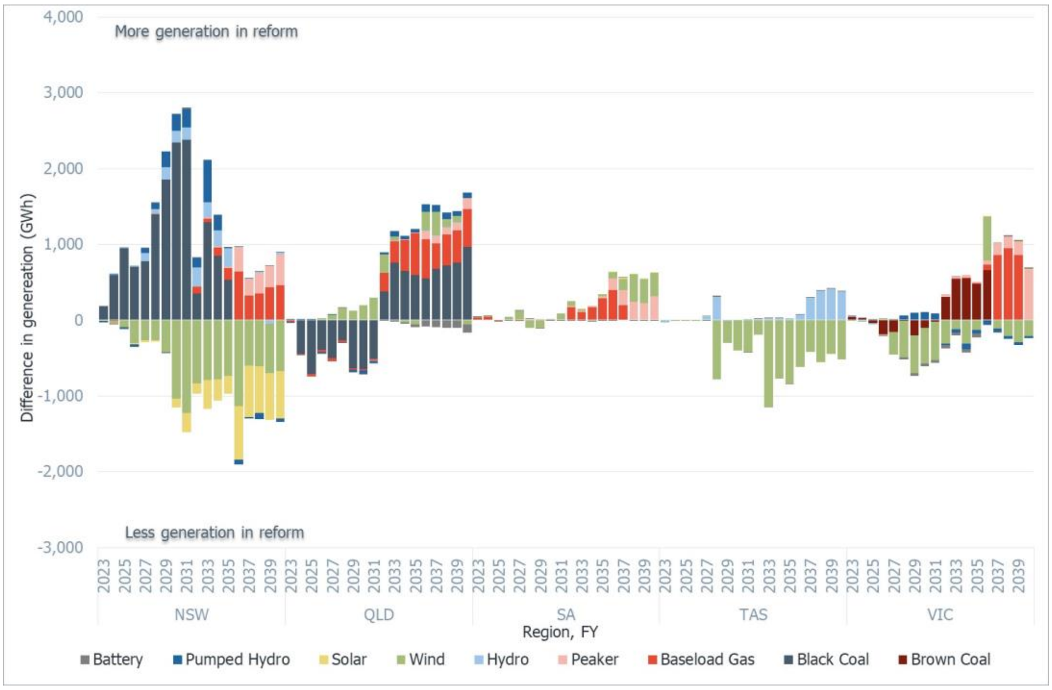
Figure 13 and Figure 14 provides a more detailed comparison of operating cost and generation patterns between the two cases. The operating cost differences are minor in early years before 2030. As discussed in Section 4.2, when coal units are still relatively abundant, the costs of running them to provide system strength or curtailing IBR are small. After 2030, when most coal units have retired, these costs become larger as gas generators are more expensive. As discussed in Section 4.4.3, our modelling is likely to underestimate the true cost of the No Reform case, as we have assumed that system strength would be “built out” as every new IBR brings their own remediation schemes leading to no operational curtailment or connections delay. In practice, however, these issues are likely to persist without the reform, at least for the first few years, and will increase the operating cost in the No Reform case. We have performed a sensitivity to demonstrate the cost of connections delay, as discussed in Section 4.3.1.

Figure 13 Annual operating cost, Reform vs No Reform



Source: Cornwall Insight

Figure 14 Difference in generation output, Reform vs No Reform



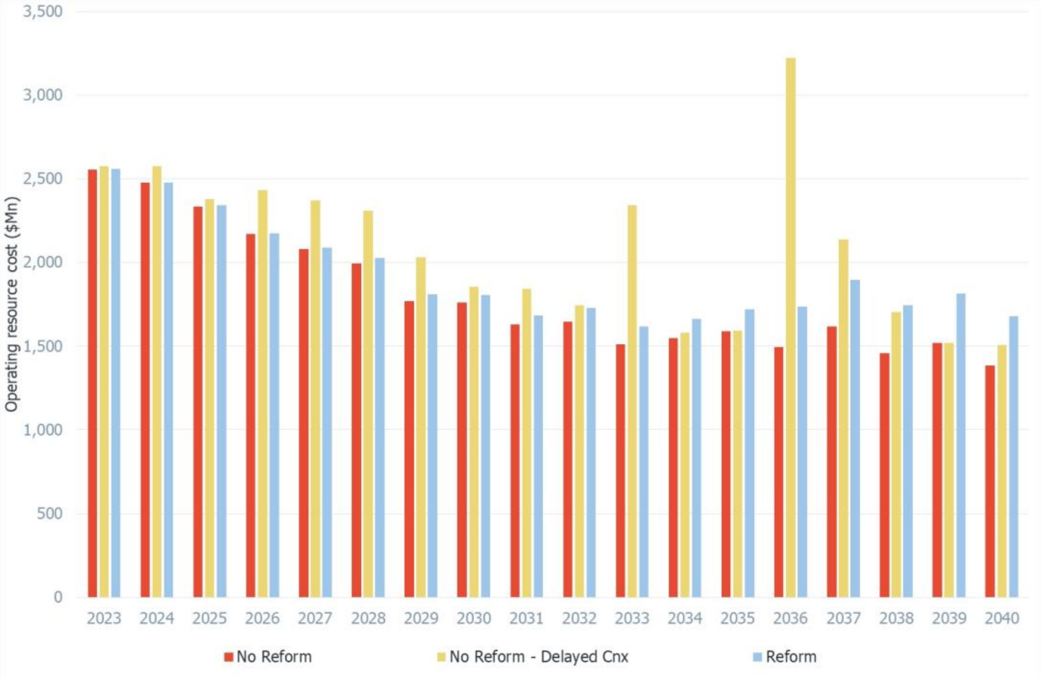
Source: Cornwall Insight

4.3.1 A sensitivity of delayed connection in the No Reform case

To get some insight into the additional inefficiencies associated with the No Reform case, we have run a sensitivity where new IBR projects experience connection delay. We assume they will take on average an extra year before being able to fully operate in the market, despite incurring initial capital cost.[15] The resulting operating costs are shown in Figure 12. With connections delay, the operating cost of No Reform is now greater than the Reform case in earlier years. The No Reform operating cost with connections delay is significantly higher than the Reform case in FY32/33 and FY35/36 as new renewable capacity are needed after major baseload retirement.

Overall, if all new IBR entrants on average would experience a one-year connection delay, the No Reform operating cost in NPV terms would be $1.9Bn higher than the Reform case, bringing the net benefit of the reform package to $4.0 Bn. While the sheer operational inefficiency and resulting price impact would likely lead to alternative initiatives to mitigate connections delay in the No Reform case, this sensitivity shows the cost of No Reform would in practice be much higher.

Figure 15 Operating cost - No Reform with connections delay



Source: Cornwall Insight

4.4 Potential limitation of our modelling approach and assumptions

4.4.1 Restrictions on supply source of system strength

As discussed in Section 3.2.2, our current modelling only includes syncons (network options) and synchronous generators and storage assets (non-network options) as the supply for system strength. It does not include new technologies such as grid-forming inverters or other TNSP options such as equipment upgrade or inverter retuning. Their exclusion could potentially bias the estimate of the reform benefit. However, we note that had these options be included, they should be available in both the Reform and No Reform cases.

- While other TNSP options such as equipment upgrade or inverter retuning would be available in the No Reform case, the TNSP is constrained by the minimum system strength gap framework and cannot co-optimise their deployment with its other investment or all IBR entrants' uncoordinated remediation schemes. On the contrary, in the Reform case, the TNSP can better coordinate all

[15] *That is, they will be "invested" and incur the capital cost in the same year as in the normal No Reform case but will not produce energy in the model until the next year.*

options. Therefore, adding these other options would likely to increase the benefit estimate for the Reform case.

- The inclusion grid-forming inverters, on the other hand, would likely lead to smaller benefit for the Reform case if their cost is sufficiently low. A major benefit of the Reform case is the scale efficiency and the co-optimisation between network and non-network options in system strength procurement. To the extent that the adoption of grid-forming inverters reduces the need for the network and non-network options currently in our model, the benefit of the Reform case would also be lower. We are currently undertaking additional modelling to quantify the reform benefit in a scenario with large uptake of more advanced inverters.

4.4.2 Regional approach to model system strength

The regional modelling approach (See Section 3.2.4) will likely overestimate the Reform benefit in the early years. This is because it overstates the existing synchronous fleet's contribution to system strength supply in area remote from current synchronous generation centres. This will lead the model to build too few syncons in early years of the Reform case when synchronous (especially coal) units are still abundant in the NEM, which underestimates its cost. However, this effect is partially offset as the regional approach also means system strength cannot be shared across regional borders in the model. For example, syncons built near either side of the NSW/Victorian border could only supply system strength in their respective regions. This effect is smaller in later years as most of the existing synchronous, especially coal, fleet retire. As system strength in late years are mostly supplied by newly built syncons and pumped hydro, the modelling effectively assumes these new assets would be located at the right places based on new IBR locations.

4.4.3 The "No system strength shortage" assumption in the No Reform case

Our approach to model the No Reform case (See Section 3.3) assumes that, as every new entrant brings enough system strength investment to host their entire nameplate capacity, it would remove further system strength shortfall related operational curtailment or connection delays, and only require negligible amount of TNSP investment in addressing future minimum gap. In practice this is unlikely to be true, at least in the short term, given the existing state of the market regarding system strength investment. However, to model ongoing AEMO direction would require us make potentially unfounded guesses about how AEMO would continue to intervene in system strength in the future. For example, we might have to assume that:

- AEMO would only intervene by directing on synchronous generators only if there is a minimum system strength gap (as now)
- When intervening, AEMO would curtail IBR output to the hosting capacity associated with the minimum system strength level.

Such assumption would appear to be problematic and very inefficient when comparing the assumed IBR hosting capacity at minimum system strength (constant at 2000 MW each mainland region due to the lack of any information on future projection) against the tens of GWs IBR entrant that will enter the market before 2040. It would also exclude more effective ways of managing system strength in the absence of the reform that could arise in the future, leading to an overestimate of the cost in the No Reform case.

4.4.4 Sequential generation and system strength investment

We model generation and system strength investment in sequential steps as discussed in Section 3.3. We consider this assumption reasonable as it reflects the practical lack of perfect coordination between generation and transmission investment in general. We would like to note that under a fully co-optimised generation and system strength investment, the benefit of the proposed reform is likely to be even greater as the model would choose to invest less in the IBR that would otherwise be curtailed in dispatch, leading to additional capital cost saving from the generation sector as well.

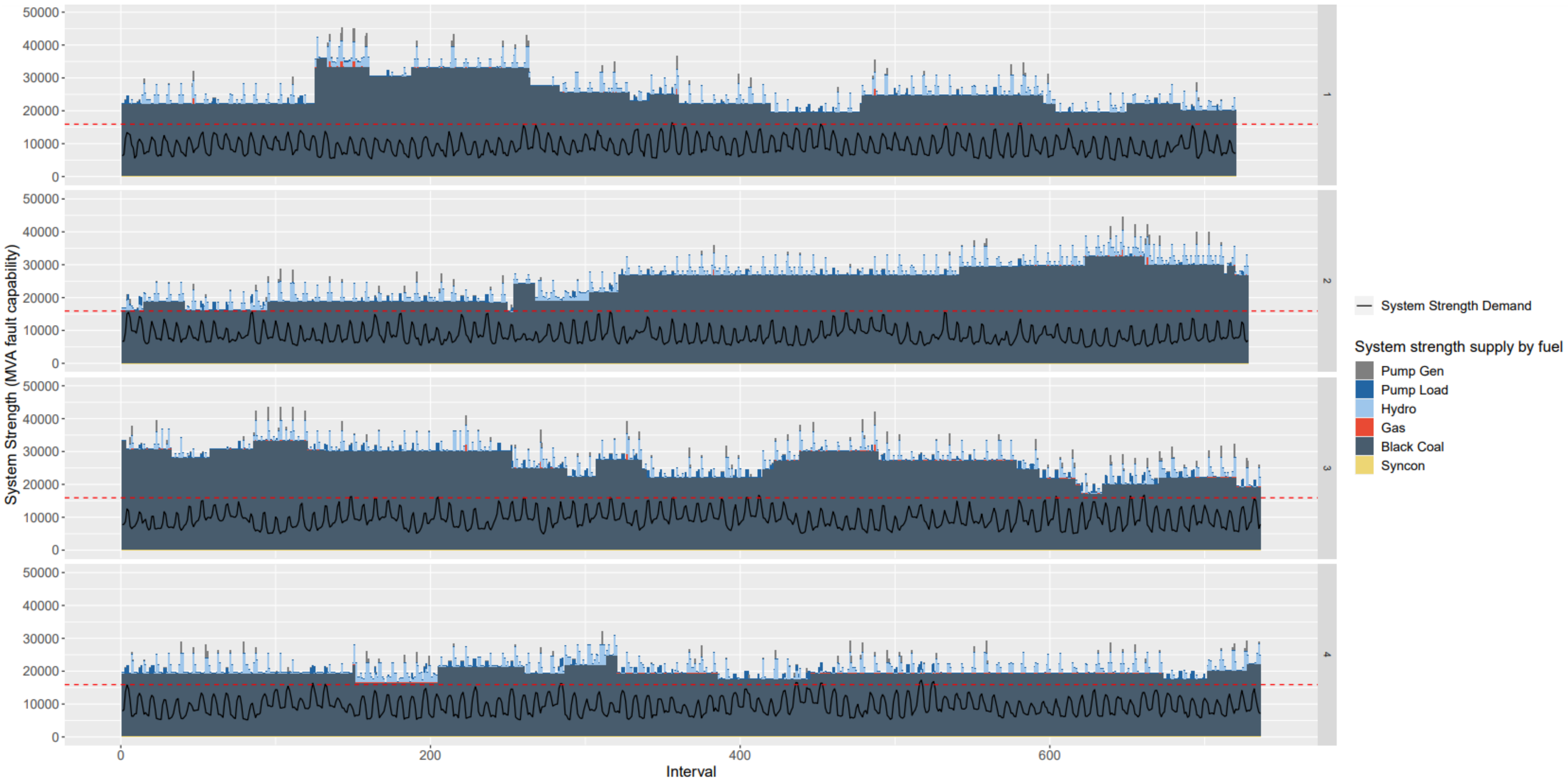
5 Appendix

5.1 System strength supply and demand for NSW in selected years

The charts in this section provide more detailed system strength supply and demand outcome for all modelled intervals for selected years in NSW. The stacked bars measure the supply of system strength by different technology, and the solid black line shows its demand (adjusted to account for reginal minimum requirement). The red dashed line is the regional minimum system strength requirement, which is a constant. When demand meets the top of the stacked chart in an interval, there is no residual system to host additional IBR output, leading to its operational curtailment.

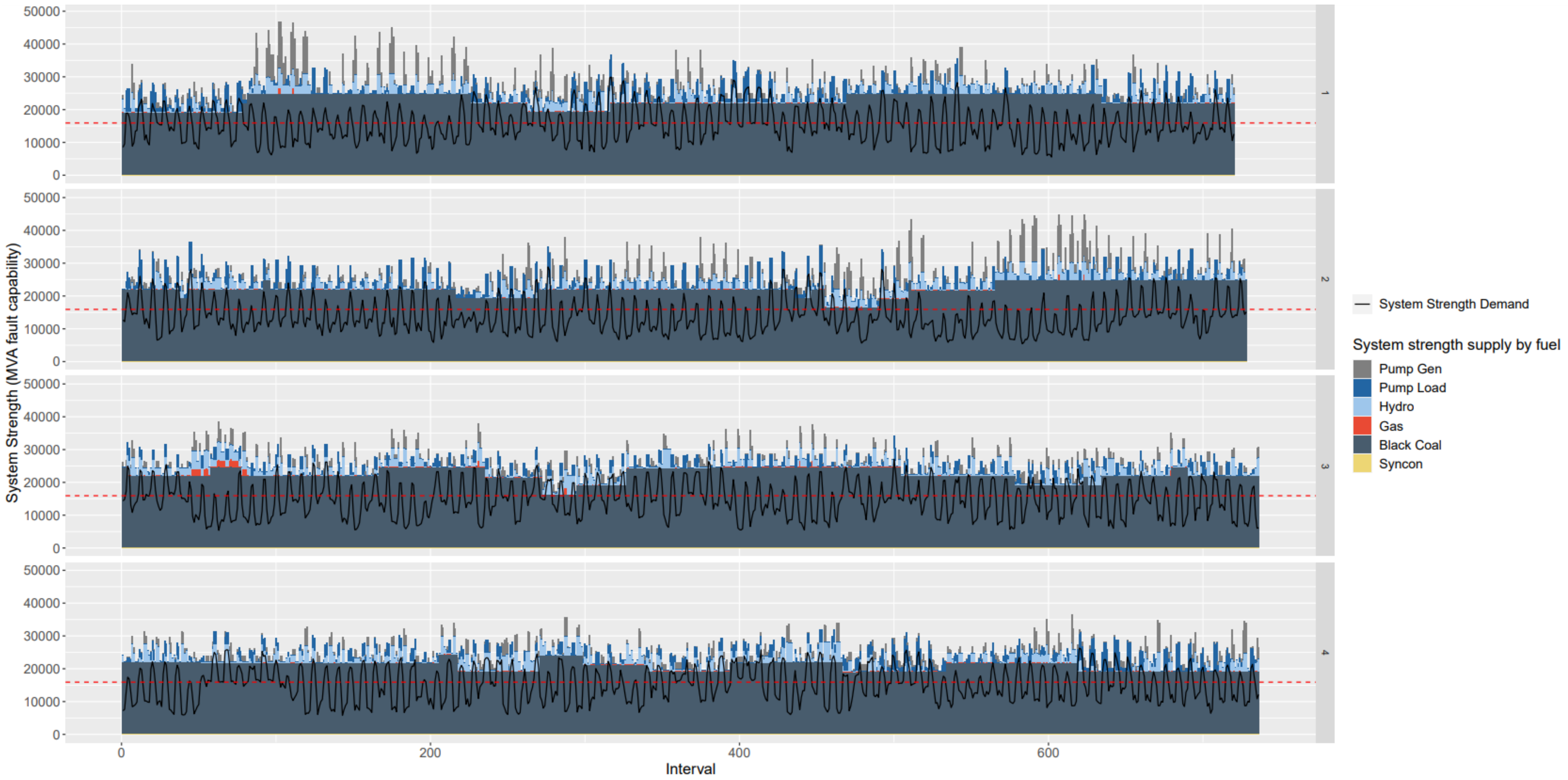
As discussed in the main text, in earlier years, synchronous units, especially coal, provide the bulk of system strength supply in NSW. After coal retirement reaches a certain threshold, new investment in syncon is required to supply system strength in the region. In later years pumped hydro units also become a major source of system strength supply.

Figure 16 NSW system strength supply and demand in FY22/23



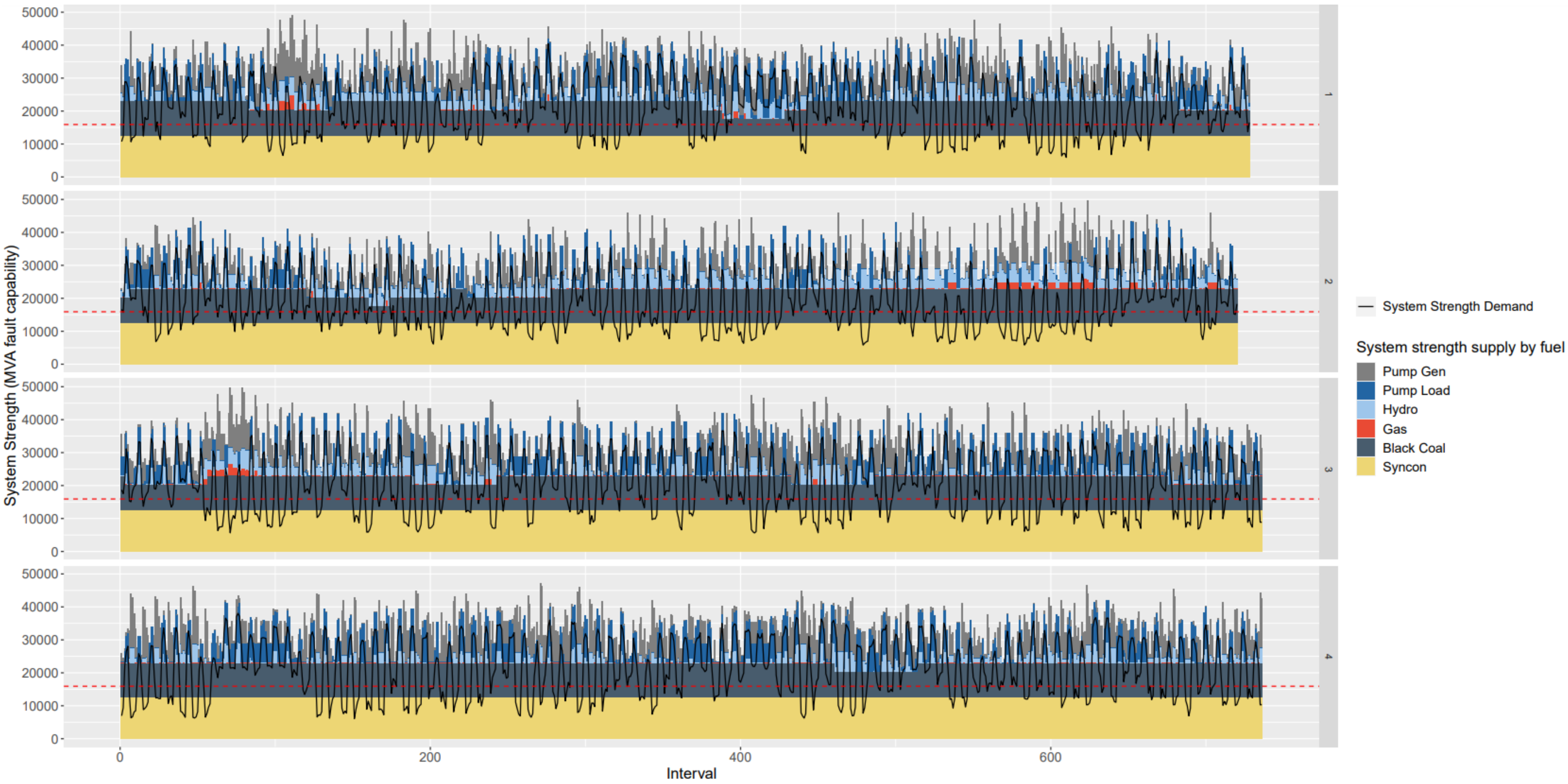
Source: Cornwall Insight

Figure 17 NSW system strength supply and demand in FY26/27



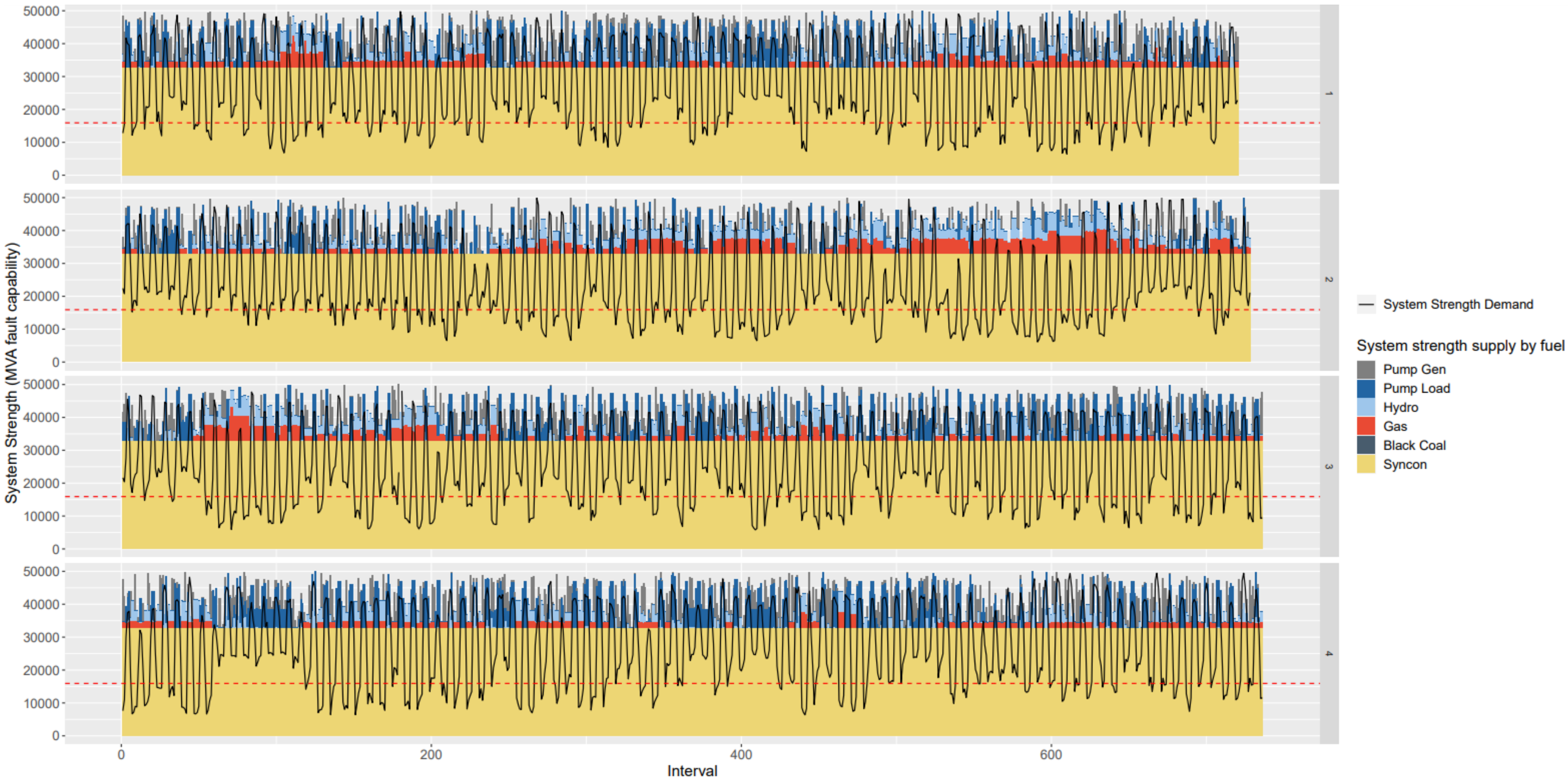
Source: Cornwall Insight

Figure 18 NSW system strength supply and demand in FY31/32



Source: Cornwall Insight

Figure 19 Figure 18 NSW system strength supply and demand in FY36/37



Source: Cornwall Insight

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