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MEMO

TO:	CMM Project Members and Technical Working Group
DATE:	11 August 2022
FROM:	George Anstey; Vakhtang Kvekvetsia; Sofia Birattari; Rebecca Ly (NERA)
SUBJECT:	**Summary of Inputs and Assumptions used in the CMM nodal model**

This memorandum presents a summary of the key inputs, assumptions and methodologies we employ for our assessment of the different Congestion Management Mechanism ("CMM") options and the Congestion Relief Market ("CRM"). The memo is organised as follows:

- Section 1 briefly presents PLEXOS, the power market modelling software we use to model a representation of the NEM;
- Section 2 details our process to represent a nodal network in PLEXOS, in order to observe locational prices in the market;
- Section 3 describes our assumptions on demand;
- Section 4 reviews the sources for inputs and assumptions on generation and storage capacity (present and future) in the NEM;
- Section 5 describes our assumptions on fuel prices;
- Section 6 describes our main modelling runs and their use in the calculation of outcomes under each CMM/CRM option;
- Appendix A contains 2022 ISP installed capacity charts by region, which we will replicate in our nodal model; and
- Appendix B contains the specifics of the ISP projects we include in our model.

1. The PLEXOS Modelling Software

PLEXOS is a cost-minimising market-modelling and system planning software package, which projects planning decisions and dispatch using a linear programming algorithm. PLEXOS forms the basis of our market modelling of the NEM.

Modelling the market using PLEXOS has a number of key advantages for quantifying the benefits of flexibility:

- PLEXOS is an industry-leading platform for modelling electricity markets for which we and stakeholders already have access to published versions run by AEMO for the NEM, namely the Integrated System Plan (ISP) and the Electricity Statement of Opportunities (ESOO) models;
- As a publicly-recognised modelling platform, stakeholders have much greater clarity and understanding of our results than if we were to use a bespoke, proprietary algorithm; and

- The software is able to optimise the long-term least cost expansion planning of generation and the short-term optimal dispatch patterns. Accordingly, we are able to run a planning study to replicate the capacity expansion modelled in the ISP in our study. Given this capacity outlook, we can then observe short-term dispatch and pricing outcomes in each half hour of the modelling horizon in order to determine outcomes under the different CMM options.

We describe our PLEXOS modelling set-up in further detail in the upcoming sections.

2. Defining the Nodal Network

We model the NEM using our PLEXOS-based nodal model, which we originally built in 2019-2020 using inputs from the 2019 ESOO and 2020 ISP models. For this exercise, we are upgrading our existing model with new nodes and new lines to reflect the generation and transmission outlook for the NEM set out in the 2022 ISP.

2.1. Overview of Nodes and Transmission Lines

The ESOO and ISP databases do not provide a nodal representation of the NEM. We developed a nodal PLEXOS model on the basis of the existing regional one and locational data provided by AEMO. The resulting nodal infrastructure is a representation of the NEM's "system normal" configuration, that is, the baseline state of the system in which transmission elements are in service and operating in their normal configuration.[1] There are 1,068 nodes in our model in total.

Our PLEXOS nodes are a synthetic representation of real-life substations that connect lines and allow generators to input energy to the grid; in practice, a PLEXOS node can be the equivalent of multiple real-life connection points combined into a substation. For instance, the model may show three power plants belonging to the same complex (e.g. Bayswater plants 1, 2 3, and 4) to be connected to the same node, while in reality each plant has its own connection point.

Table 2.1 below summarises the number of nodes in every region and the corresponding Regional Reference Node.

Table 2.1: Summary of Nodes per Region

	Number of Nodes	Reference Node	RRN Voltage (kV)
NSW	334	Sydney West	330
QLD	304	South Pine	275
SA	217	Torrens A Power Station	275
TAS	93	George Town	220
VIC	120	Thomastown	220

Source: AEMC/NERA PLEXOS model

Our PLEXOS representation of the NEM includes a detailed transmission network linking the nodes and contains 1,942 lines. The model also includes contingency constraints, to reflect AEMO's network security practice of monitoring lines and diverting flows to other lines in case of faults.[2]

[1] AEMO (May 2020), Victorian Transfer Limit Advice – System Normal, p.27.

[2] Specifically, we include an N-1 security envelope in our modelling.

Our modelled power flows obey Kirchhoff's second law and the lines have physical properties (reactance and resistance) as well as a thermal representation.[3] Using these physical properties ensures that the power flows we model reflect as closely as possible the feasible dispatch in the NEM.

2.2. Nodes and Lines Added to Reflect the 2022 ISP

2.2.1. Overview

Starting from our existing nodal model, we include additional nodes and lines for two main purposes:

1. To ensure that non-commissioned generators and batteries in the 2022 ISP (i.e. listed as "committed" and "anticipated") can deliver power to the network through a substation; and

2. To reflect the future transmission projects included in the 2022 ISP.

2.2.2. Method for new nodes and lines for future generators

In designing the new nodes and lines for generators entering the grid after the start of the modelling horizon, we ensure that the connection from the generator to its assigned substation has sufficient capacity to reach the node. i.e. the thermal limit on a transmission line is larger than the generation maximum capacity.

Whenever we cannot identify the connection from a generator to its substation, we choose the closest substation based on the network topology.

We create a new node and a new line whenever a generator leads to a sufficiently large substation that includes more than one line.

2.2.3. Method for new nodes and lines reflecting the 2022 ISP

We follow the transmission outlook set out in the 2022 ISP Step Change Scenario, in particular, Candidate Development Path 12 ("CDP12"). AEMO identifies the Step Change scenario as the most likely outcome according to the stakeholders' panels.[4] AEMO also states that CDP12 is an "optimal development path" for the Step Change scenario.[5]

We have included Priority 1, 2 and 3 projects from AEMO's 2022 ISP as well as the Marinus Link Line from 2036 (as assumed in CDP12). Priority 1 and 2 projects are either listed as "committed", "anticipated" or "actionable" by AEMO, whereas Priority 3 projects are classified as "future ISP projects".[6] Whenever future ISP projects have two options, we picked the first option by default.

Appendix B provides more details on the PLEXOS implementation of the ISP projects.

[3] Kirchhoff's second law states that the (directed) sum of potential differences across a closed loop in a circuit is zero. Source: Royal Academy of Engineering.

[4] AEMO (30 June 2022), 2022 Integrated System Plan, pp. 33-34.

[5] AEMO (30 June 2022), 2022 Integrated System Plan, p. 92.

[6] AEMO (30 June 2022), 2022 Integrated System Plan, Appendix 5.

3. Projecting Demand

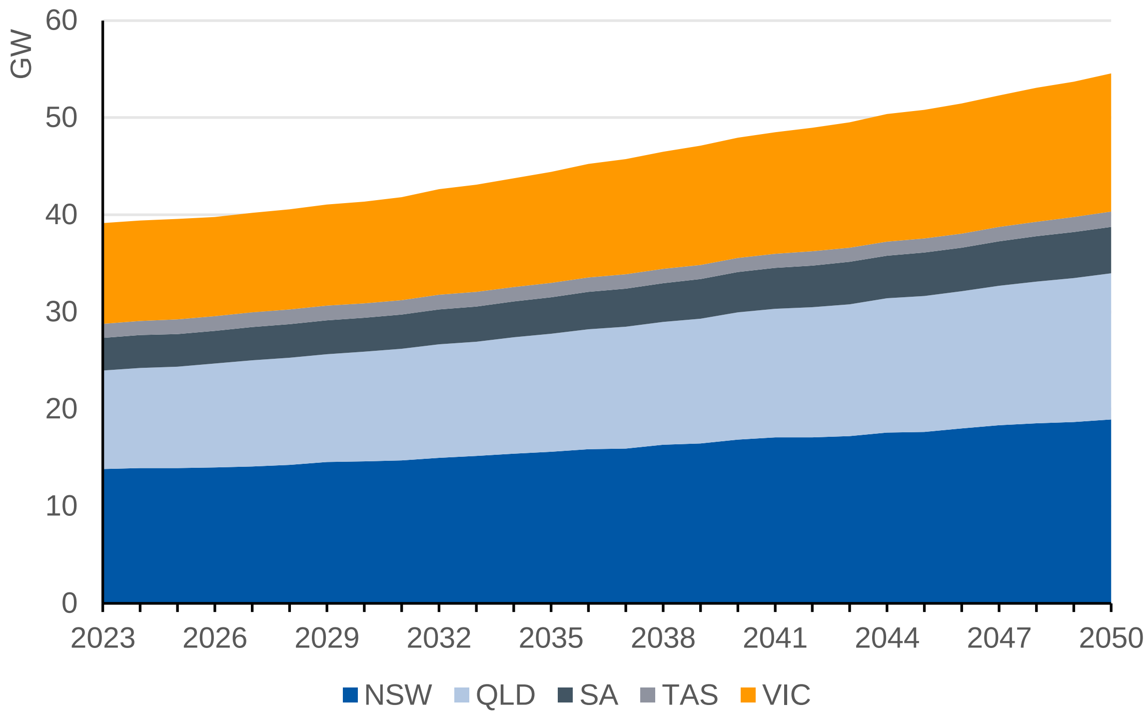
The ISP contains assumptions on sub-regional demand only.[7] We allocated load to nodes based on "load participation factors", which we derived from data provided by AEMO.

We model demand using the Probability of Exceedance 10 (POE-10, i.e. the demand forecast at the upper decile of the distribution) demand scenario, as provided in the 2022 ISP modelling material. We use Operational Sent-Out ("OPSO") forecasts, which are net of the contribution of rooftop PV to load. As mentioned above, we follow the forecast for the Step Change scenario.

The 2022 ISP adopts a "rolling reference year" approach in demand traces to capture weather diversity in the modelling horizon.[8] A 10-year sequence of reference years (2010/11 to 2019/20, plus an additional "dry year") is rolled forward and repeated over the modelling horizon.

Figure 3.1 shows the evolution of the forecasts over the entire ISP horizon.

Figure 3.1: Summer Peak Demand, Step Change Scenario



Source: AEMO Forecasting Portal..

[7] That is, the ISP 2022 models SA, TAS and VIC as one region, while it splits NSW into four sub-regions and QLD into three.

[8] AEMO (30 June 2022), 2022 Integrated System Plan, Model instructions, pp. 4-5.

4. Representing the ISP 2022 Generation and Storage Capacity Mix

4.1. Generation Capacity and its Properties

We aim to set up our model so that it is as close as possible to the representation of the NEM set out in the 2022 ISP and its associated PLEXOS database for the Step Change scenario. We therefore updated the list and characteristics of generators and storage units in our nodal model using new information from the 2022 ISP.

We source most generators and batteries properties from 2022 ISP Step Change Scenario, as represented in the published PLEXOS database and the 2022 Inputs and Assumptions Workbook published with the Final ISP. Properties include, for instance, the maximum capacity of each plant, rating and unit costs.

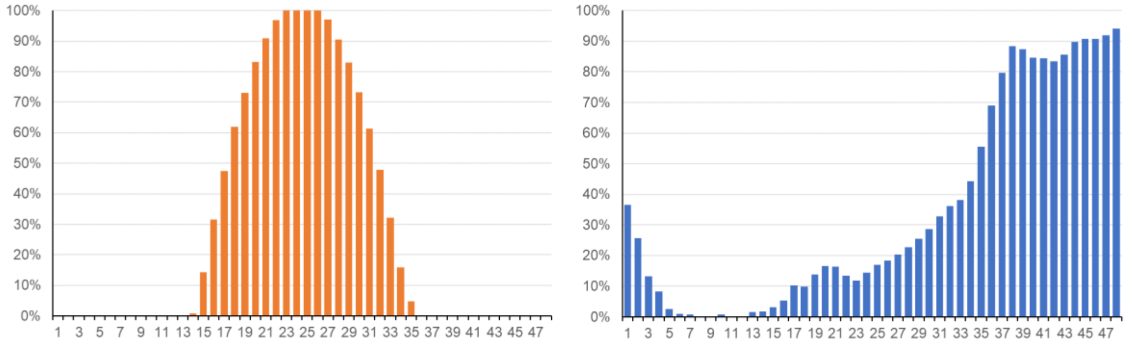
In addition, we add a number of generator properties from the 2021 ESOO model that relate to short-term dispatch dynamics and are therefore absent or simplified in the ISP database. These properties include: minimum stable level, minimum up time, must-run units, fixed load, minimum load, maximum ramp up, maximum ramp down, forced outage rate, outage factor and minimum time to repair.

The ISP regional models allocate all generation to a representative node – either the region's reference node or a node for each "sub-region", as described above. We matched generators to nodes by investigating the physical locations of the network connection points and generators. Our nodal database assigns generators to nodes on the basis of their proximity to a substation/set of buses.

We adopt ISP 2022 assumptions on the existing generation fleet. We also programme in scheduled "committed" and "anticipated" projects – largely solar, wind and pumped hydro – expected to be commissioned after 2023, when the 2022 ISP simulation starts. We retire capacity following expected retirement dates in the ISP 2022 assumptions.

We have modelled the availability of renewable plants using rating traces obtained from the ISP 2022 database. As is the case with demand, AEMO uses a "rolling reference year" approach to ratings traces, following the same methodology described for demand. Traces are available half-hourly at plant level, for existing plant, or by REZ for candidate entrants that the model can choose to build in a planning simulation. The traces contain the respective plant's rated generation capacity in every period, normalised to a 1 MW unit, as illustrated in Figure 4.1.

Figure 4.1: Half-hourly Rating Trace on Sample Day for a Solar (Left) and Wind (Right) Generator



Source: AEMO (June 2022), ISP 2022 database. The charts show half-hourly rating (normalised to a 1MW plant) on 31 July 2023 for a solar and a wind plant in the North-West NSW Renewable Energy Zone (REZ). The choice of the day is entirely aleatory for this representation.

4.2. Modelling Generation Expansion

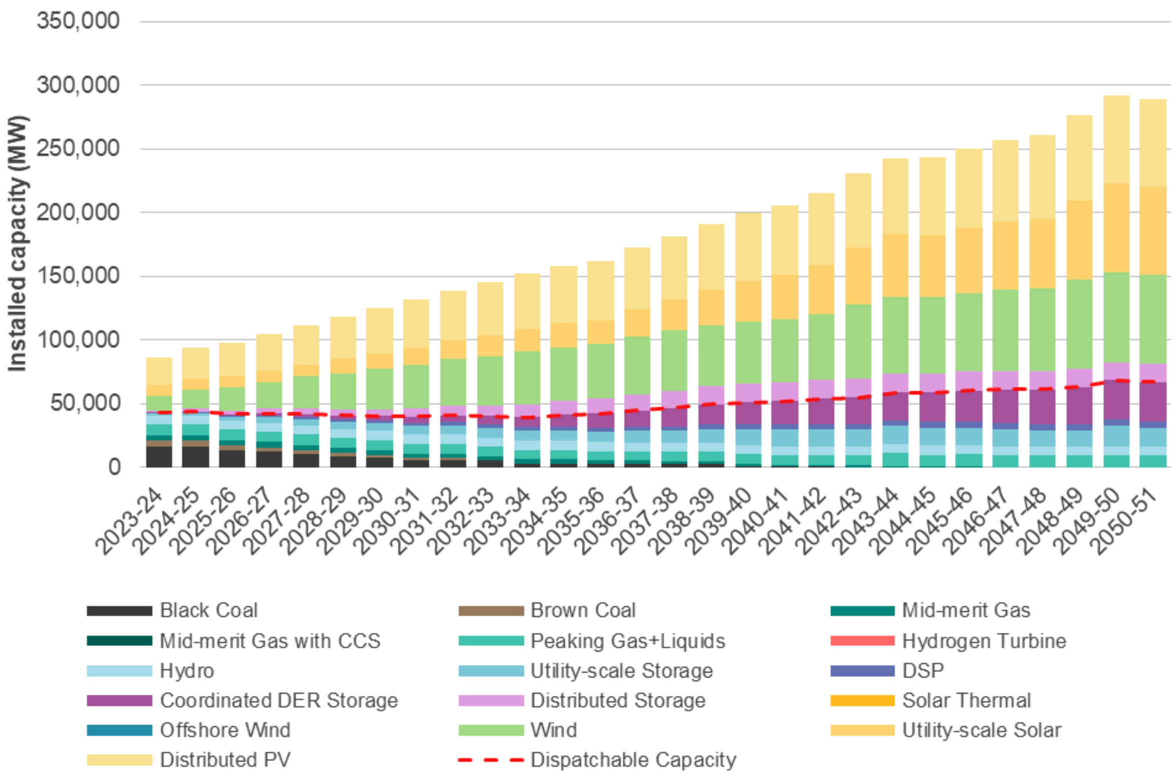
4.2.1. "Long-term" modelling run to align capacity between the nodal model and the 2022 ISP

The assessment of the CMM and CRM implementation options will focus on short-term dispatch and pricing dynamics. However, we will ensure consistency with the 2022 ISP by basing the capacity mix of our modelling runs on a long-term capacity expansion run.[9] The aim of this run is to replicate as closely as possible the generation outlook projected by the 2022 ISP, specifically its Step Change scenario with "CDP12" transmission, in our nodal model.

Figure 4.2 represents the capacity mix in the 2022 ISP Step Change (CDP12) scenario. See also the break-down of capacity by region in Appendix A.

[9] Note that this particular process is in progress at the time of writing this memorandum. We therefore share the specifics of the ISP assumptions we will replicate and we will share the results of this replication in our model once they become available.

Figure 4.2: NEM Capacity, 2023-2051



Source: AEMO (June 2022), 2022 Final ISP Results Workbook – Step Change – Case CDP12

Like the ISP, our PLEXOS model database includes:

- Existing and scheduled (programmed in) generators and storage units, which enter and exit the system on pre-established dates. As explained above, we align these plants and their capacity to the assumptions contained in the 2022 ISP Step Change PLEXOS database;

- "Candidate" generators and batteries, that a PLEXOS long-term simulation can choose to add to the system to meet increased demand and other system requirements, following a cost optimisation logic.

To replicate the ISP's build pattern of new capacity, we rely on the ISP published capacity outlook by region and REZ.[10] For renewable candidates (wind and solar) we constrain new build in our model to match total capacity by REZ and region as published in the 2022 ISP through custom constraints in PLEXOS. The PLEXOS simulation optimally allocates the target capacity to the nodes within each REZ, based on total costs, nodal demand and available transmission capacity. For gas and storage candidates we follow a similar procedure at regional level. We therefore recreate the ISP capacity outlook in a nodal dimension.

[10] AEMO (30 June 2022), 2022 Integrated System Plan - Supporting material: Generation outlook. URL: https://aemo.com.au/energy-systems/major-publications/integrated-system-plan-isp/2022-integrated-system-plan-isp. Accessed 10 August 2022.

4.2.2. Specifications of “candidate” plants for new capacity build

The Step Change “CDP12” scenario does not build any additional coal, biomass, hydrogen, solar thermal and offshore wind capacity. Therefore we only allow our model to build new gas, wind and solar plant. Storage capacity expansion covers large scale batteries and pumped hydro storage (PHES). We constrain PLEXOS to build 1-hour, 2-hour, 4-hour and 8-hour large-scale batteries.[11] We model entrant Pumped Hydro as batteries, with the same methodology described above, except we use 8-hour, 24-hour and 48-hour batteries and different cost profiles, also based on the ISP assumptions.

In the case of new renewable capacity, we do not have an individual generation trace for most nodes, as is the case for existing wind and solar capacity. We have used traces by REZ for the missing nodes, published as part of the 2022 ISP PLEXOS model.

We adopt 2022 ISP assumptions on build costs of new technology. We use the different build cost profiles for each of the new technology per year and per sub-region in the case of natural gas and storage candidates, and by REZ for wind and solar.

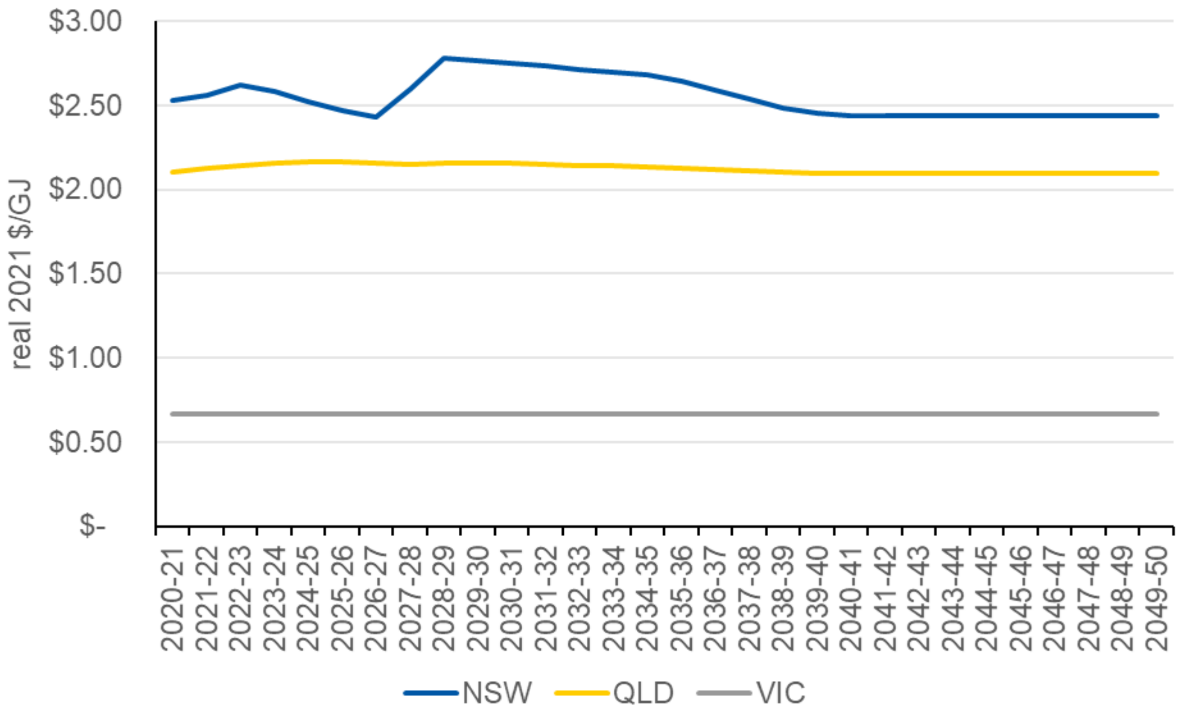
We constrain the number of nodes at which construction of gas and renewable plant can take place. We also constrain building of wind and solar new capacity to REZ and non-REZ areas where the ISP models new build. For thermal generators, we constrain new construction to nodes with existing generation outside of metropolitan areas. For large-scale batteries, we build both within and outside REZs (including the nodes already selected for thermal build and nodes with existing renewable generators). Construction of Pumped Hydro is constrained to areas with existing hydro generation, as a proxy for areas with terrain and hydro-geological conditions suitable for this technology.

[11] A 4-hour battery is a battery that that takes 4 hours to discharge at full capacity (for instance, a 1 MW battery can generate 4 MWh with a full charge)

5. Fuel Prices

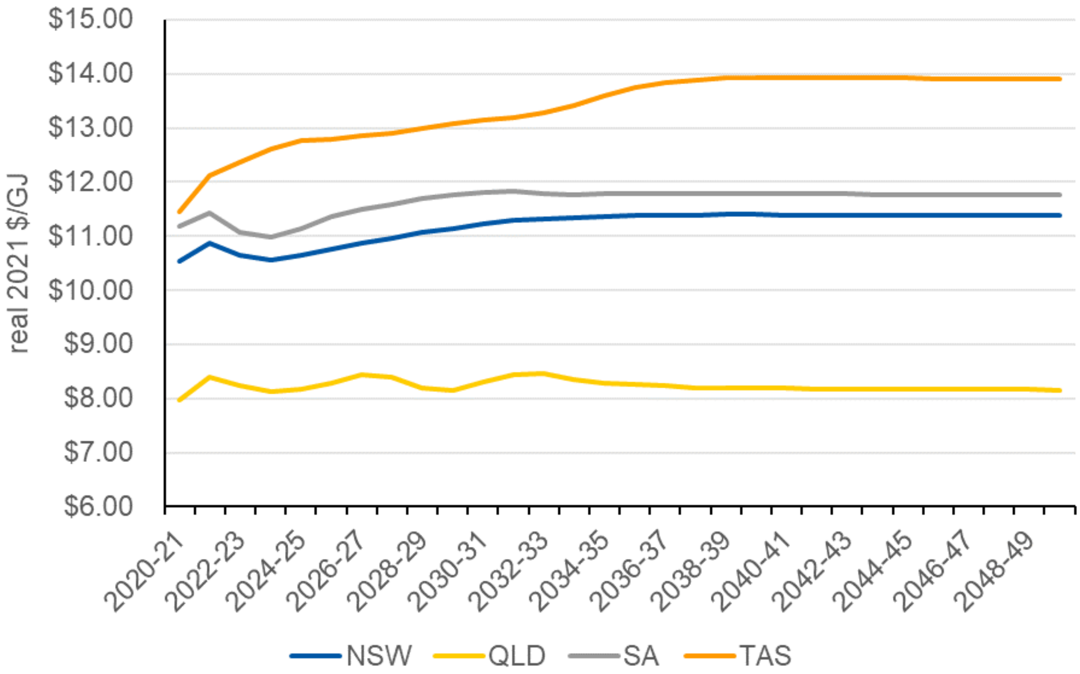
We use ISP 2022 assumptions on fuel prices in real 2021 $/GJ, as shown in Figure 5.1, Figure 5.2, and Figure 5.3 below. As can be seen from the Figures, AEMO forecasts that gas prices will rise in real terms until the mid-2030s before plateauing until the end of the modelling horizon. Coal prices remain broadly flat in Queensland and Victoria but decrease from 2030 to their level in 2020 in New South Wales.

Figure 5.1: Average Coal Prices, Step Change Scenario



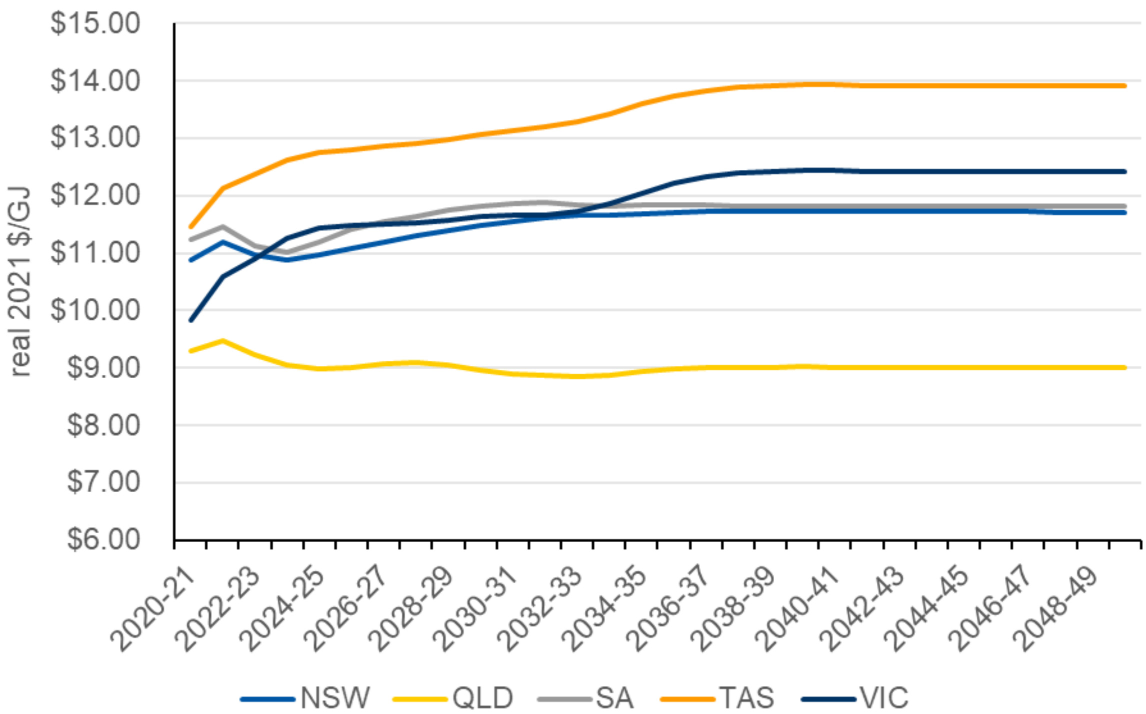
Source: AEMO (June 2022), 2022 ISP Inputs and Assumptions Workbook.

Figure 5.2: Average Gas Prices (CCGT), Step Change Scenario



Source: AEMO (June 2022), 2022 ISP Inputs and Assumptions Workbook.

Figure 5.3: Average Gas Prices (OCGT & Steam), Step Change Scenario



Source: AEMO (June 2022), 2022 ISP Inputs and Assumptions Workbook.

6. Main Modelling Runs and their Use in CMM/CRM Assessment

We will use our PLEXOS nodal model, with the generation and transmission assumptions outlined in the previous chapters, to run short-term simulations of dispatch and pricing outcomes in the NEM. These runs will serve as baseline for "status quo" outcomes in the absence of access reform and "optimal" dispatch outcomes under reform. We will also use outputs from these runs to inform our calculations of the key elements of the CMM options and CRM such as differentials between regional reference prices and LMPs at each node, generator access and entitlements to redistribute congestion rent. We describe our two main model runs, how we use them to assess CMM/CRM options and potential sensitivities we will consider below.

Note that the focus of this memo is on key inputs and assumptions for our nodal model. We therefore do not describe the methodology for access and entitlement calculation under each option considered in this document.

6.1. Our Two Main Modelling Runs: "Cost-Reflective" and "Disorderly" Bidding

We base our analysis on two main types of modelling runs, representing potential "optimal" dispatch under access reform and the current status quo of the NEM, respectively. Both runs are short-term dispatch runs in PLEXOS and assume the same capacity mix, modelled on the ISP Step Change Scenario as described in Section 4.2.1

We define our first modelling run as **"cost-reflective"**, as generators bid their available capacity in every half-hourly interval at a price equal to their short-run marginal cost. This is the optimal outcome that an access reform aims to achieve through efficient price signals.

Our **"disorderly bidding"** run, on the other hand, reflects the incentives currently present in the NEM to bid at the market floor for plants behind transmission constraints whose bids are settled at the RRP. Generators that have a marginal cost below the RRP but are in an export-constrained node are overcompensated for their generation by the difference between the LMP and the RRP. In such circumstances, they have incentives to bid to the market floor price of *minus* $1,000/MWh in order to be dispatched by AEMO in preference to lower-cost plant (known as "race to the floor bidding"). Distorting bids therefore has the potential to increase system costs because AEMO selects the lowest-cost combination of plant to meet load given the bids submitted.

We identify the incentive to bid at the floor in PLEXOS through the following method:

1. **Identify Pattern of Competitive Dispatch ("Cost-Reflective" Run):** Run the "cost-reflective" run described above. In this run, generators bid their short-run marginal cost as an offer price and PLEXOS selects the cost-minimising dispatch.
2. **Identify Generators with an Incentive to Race to the Floor (Off-Model Manipulation):** From the cost-reflective run in step 1, in every half-hour of the modelling horizon we identify generators that:
   A. Generated below their available capacity;
   B. Had a short-run marginal cost lower than the price they would have received under regional settlement for half-hour;

C. Satisfy only B) and not A), but *a generator at the same node satisfies both.*

These generators have an incentive to bid to the market floor price in order to secure priority dispatch and earn the regional reference price. We exclude all generators located at regional reference nodes from this set, as they would not realistically face a constraint. We also exclude all storage and PHES units from this dynamic; however, we will be able to observe differences in storage operation between the cost-reflective and disorderly runs.

3. **Distort Bidding and Re-run Dispatch ("Disorderly" Run):** Re-run PLEXOS such that generators identified in step 2 are constrained to bid *minus* $1,000/MWh in all half-hours where they have an incentive to race to the floor. All generators bid their SRMC in the remaining settlement periods.

We can run these two types of runs for a series of sample years (e.g. 2025, 2030, 2035, 2040), to observe the impact of disorderly bidding over the ISP modelling horizon.

6.2. Use of the "Cost-Reflective" and "Disorderly" Runs in Each CMM/CRM Option

The "cost-reflective" and "disorderly" runs provide data for us to derive the key outcomes of the different CMM and CRM options considered. The table below summarises the modelling tools proposed for calculating generation, LMPs, RRPs and access parameters for each market design option: this information allows us to calculate generators' and storages' revenues and therefore distributional effects of each option.

Table 6.1: Usage of PLEXOS Runs Under Different CMM/CRM Options

Design Option	Source for Generation, LMP, RRP	Source for Access Calculation
CCM – Pro-rata Access	PLEXOS cost reflective bidding	Pro-rata Access Allocation Formula*
CCM – Pro-rata Entitlement	PLEXOS cost reflective bidding	Pro-rata Entitlement Allocation Formula*
CCM – Winner-takes-all	PLEXOS cost reflective bidding	Generation based on PLEXOS disorderly bidding
CMM – Inferred economic dispatch	PLEXOS cost reflective bidding	Generation based on PLEXOS cost reflective bidding
CRM	PLEXOS cost reflective bidding	Generation based on PLEXOS Disorderly bidding

**See ESB working papers for access and entitlement calculation formulas*

The main group of runs described in Table 6.1 uses PLEXOS cost-reflective bidding as we assume that the CMM/CRM will incentivise plants to bid their true cost, as they are settled for congestion relief or increase under the mechanisms under consideration. We are also considering introducing several sensitivities for each option to explore specific circumstances, such as:

- Using disorderly bidding instead of cost-reflective as a source for dispatch outcomes, to illustrate that such behaviour would become unprofitable for generators under the CMM/CRM;
- Allocating access/entitlement excluding out-of-merit generators, to study the difference in financial outcomes for these generators with and without the mechanism;

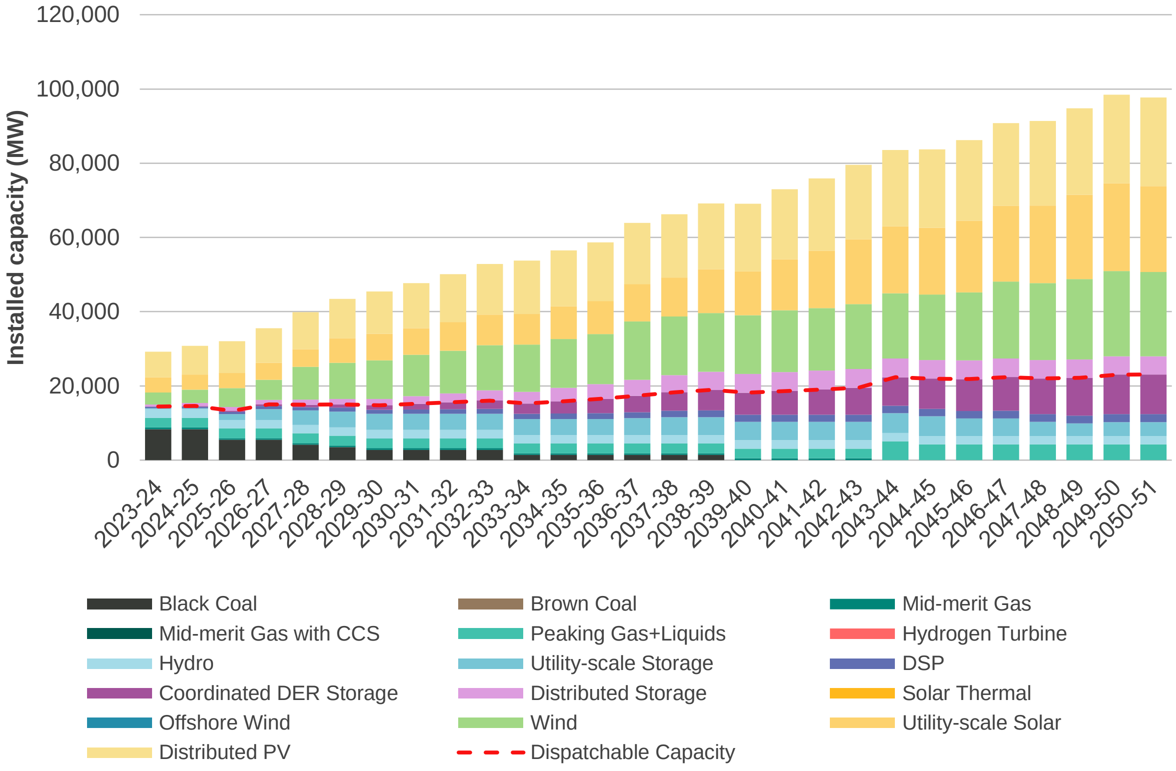
- Accounting for a percentage of capacity subjected to PPA agreements; the profits of these generators takes into account the PPA strike price; and
- Accounting for an imperfect uptake of the CRM, where a subset of generators opt-out of the CRM.

We will provide further illustrations of the methodology for each option and sensitivity in future documents.

Appendix A. Break-down of ISP Installed Capacity by Region

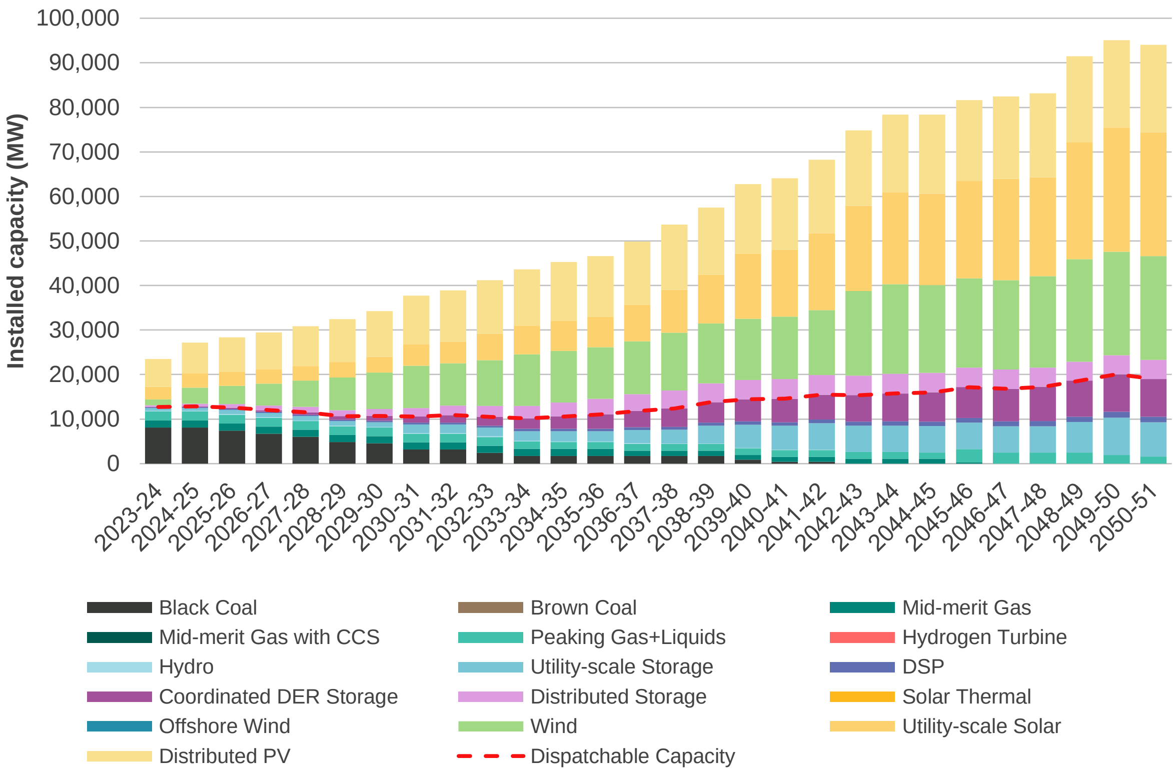
The charts below represent the break-down of installed capacity as projected by the 2022 ISP Step Change Scenario (CDP12 case). We report this information as it forms the basis of the PLEXOS constraints which we will use to align generation and storage capacity between our model and the ISP.

Figure A.1: NSW Capacity, 2023-2051 (MW)



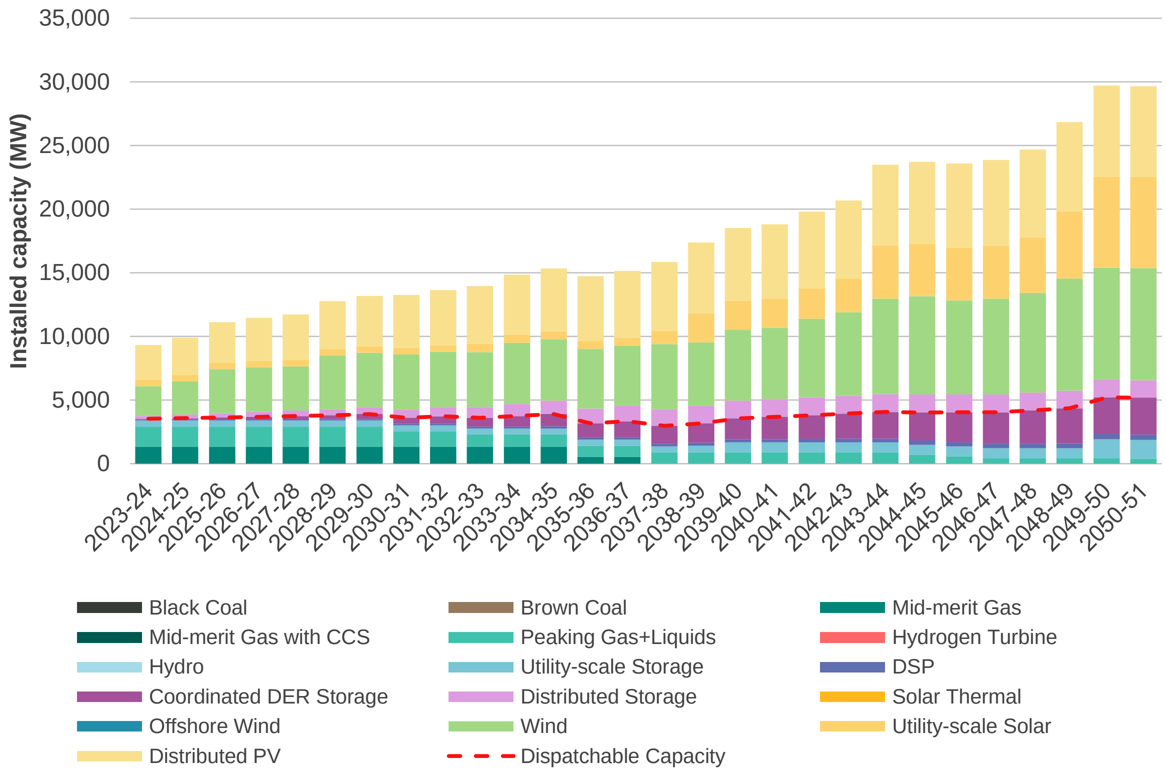
Source: AEMO (June 2022), 2022 Final ISP Results Workbook – Step Change – Case CDP12

Figure A.2: QLD Capacity, 2023-2051 (MW)



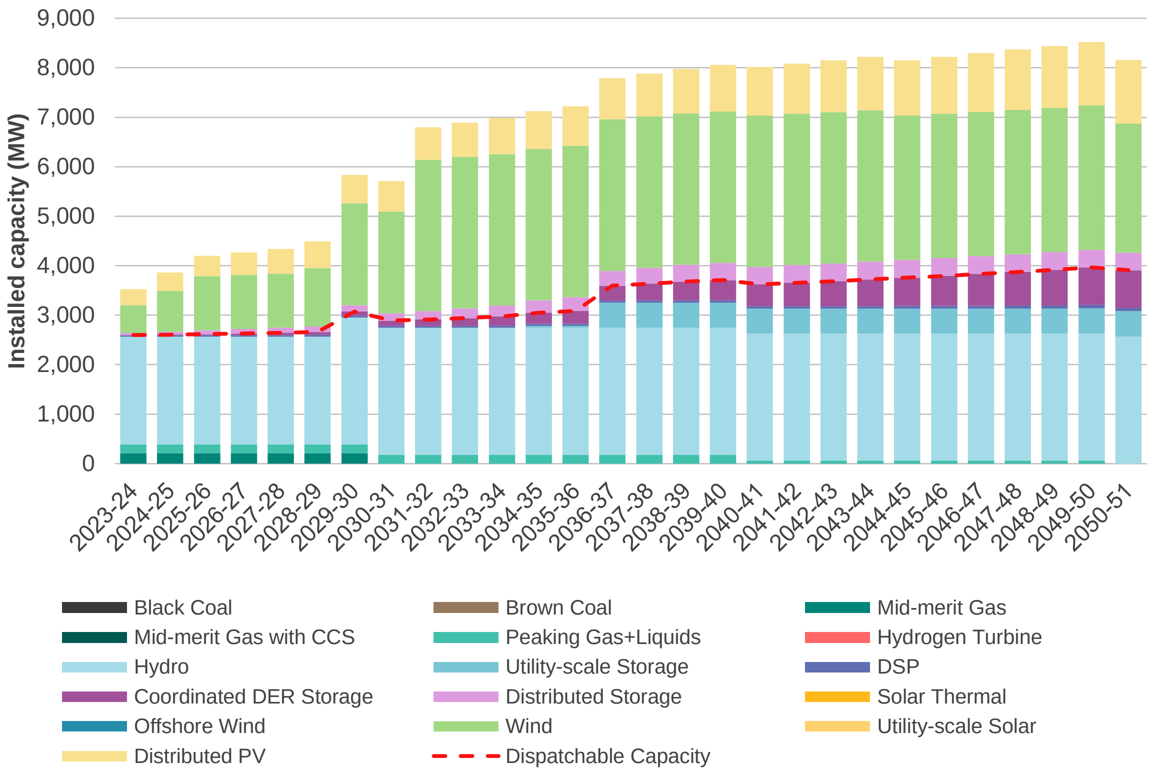
Source: AEMO (June 2022), 2022 Final ISP Results Workbook – Step Change – Case CDP12

Figure A.3: SA Capacity, 2023-2051 (MW)



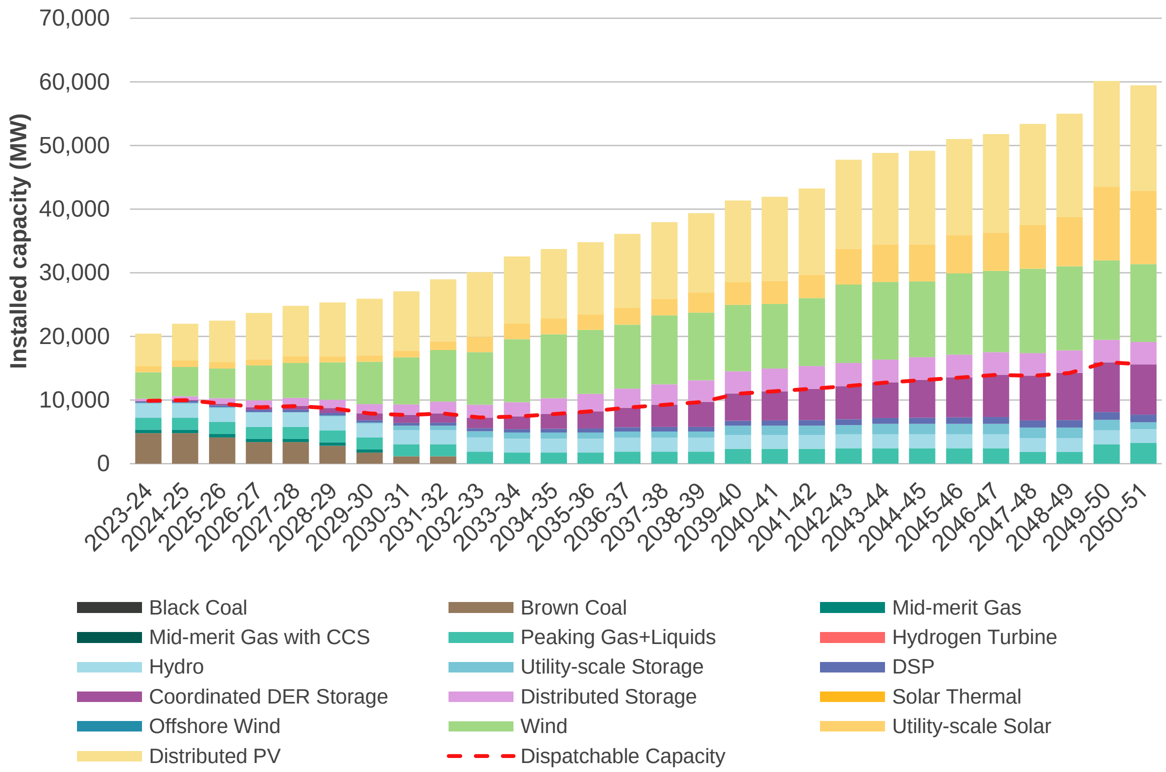
Source: AEMO (June 2022), 2022 Final ISP Results Workbook – Step Change – Case CDP12

Figure A.4: TAS Capacity, 2023-2051 (MW)



Source: AEMO (June 2022), 2022 Final ISP Results Workbook – Step Change – Case CDP12

Figure A.5: VIC Capacity, 2023-2051 (MW)



Source: AEMO (June 2022), 2022 Final ISP Results Workbook – Step Change – Case CDP12

Appendix B. PLEXOS Implementation of ISP Projects

Eyre Peninsula Link

- Description:
  - A new 132 kV double-circuit line from Cultana to Yadnarie, with the option to be energized at 275 kV if required in the future
  - A new 132 kV double-circuit line from Yadnarie to Port Lincoln
- Status: Committed
- Implementation date: December 2022
- Network capacity: Cultana-Yandarie 300 MVA, Yadnarie-Port Lincoln 240 MVA

Table 2: Plexos implementation of Eyre Peninsula Link

Line	Max Flow (MW)	Min Flow (MW)	Resistance (p.u.)	Reactance (p.u.)
Cultana-Yadnarie	285	-285	0.097683	0.369315
Yadnarie-Port Lincoln	228	-228	0.0894	0.338

Source: AEMO, Draft 2022 Integrated System Plan.

Northern Queensland REZ (QREZ) Stage 1

- Description:
  - Conversion of one side of the coastal 132 kV double-circuit transmission line to permanently operate at 275kV, as the third transmission line between Ross and Woree substations
  - Associated line reactor at the Woree Substation end
  - Establishment of a 275 kV bus at Woree Substation
  - Construction of a 275 kV bay at Ross Substation
  - Installation of a 275/132 kV transformer at Tully Substation
- Status: Anticipated
- Additional network capacity (MW): up to 500MW of new generation
- Implementation date: November 2023

Table 3: Plexos implementation of the Northern QREZ Stage 1

Line	Max Flow (MW)	Min Flow (MW)	Resistance (p.u.)	Reactance (p.u.)
Woree to Ross	546.25	-546.25	0.018966	0.1465

Source: AEMO, Draft 2022 Integrated System Plan.

Sydney Ring

Option 1: Sydney Ring Northern 500 kV loop

- Description:
  - A new 500 kV double-circuit line between Eraring substation and Bayswater substation
  - A new 500 kV substation near Eraring (Additional scope added by AEMO)
  - Two 500/300 kV 1,500 MVA transformers at Eraring substation.
- Status: Actionable
- Additional network capacity (MW): 5,000, to accommodate new generation from North of Bayswater and 2/3 generation from Centra West NSW
- Timing: July 2027

Table 4: Plexos implementation of Sydney Ring

Line	Max Flow (MW)	Min Flow (MW)	Resistance (p.u.)	Reactance (p.u.)
Bayswater to Eraring 1	2500	-2500	0.000872	0.011718
Bayswater to Eraring 2	2500	-2500	0.000872	0.011718

Source: AEMO, Draft 2022 Integrated System Plan.

Option 2: Sydney Ring Southern 500 kV loop

- Description:
  - A new 500 kV double-circuit line from the Bannaby substation to a new overhead/underground transition site
  - 8 km of tunnel installed underground 500 kV cables from the transition site to new substation in the locality of South Creek (Additional scope added by AEMO)
  - Establish 500/330 kV substation in the locality of South Creek
  - Cut-in both Eraring-Kemps Creek 500 kV circuits at the substation in the locality of South Creek
  - Two new 500/330 kV 1,500 MVA transformers at the new substation in the locality of South Creek
  - Replace a section of existing Bannaby-Sydney West 330 kV to double-circuit line between the locality of South Creek and Sydney West
  - Uprate the existing line between Bannaby and the locality of South Creek from 85C to 100C operating temperature
  - Cut-in Bayswater-Sydney West 330 kV line at South Creek.
  - Cut-in Regentville – Sydney West 330 kV line at South Creek
- Additional network capacity (MW): 4,500
- Option not implemented in Plexos

Central to Southern QLD

- Description:
  - Stage 1 – Mid-point switching substation on the Calvale-Halys 275 kV
  - Stage 2 – A new 275 kV double-circuit line between Calvale and Wandoan South and 275 kV line shunt reactors at both ends of Calvale-Wandoan South 275 circuits
- Status: Future
- Additional network capacity (MW): Stage 1 – North 300 MW, South 300 MW, Increase in REZ Network Limit NQ3: 300 MW; Stage 2 – North 900 MW, South 900 MW, Increase in REZ Network Limit NQ3 900 MW.
- Implementation date: 2038-39

Table 5: Plexos implementation of Southern QLD

Line	Max Flow (MW)	Min Flow (MW)	Resistance (p.u.)	Reactance (p.u.)
Calvale to Wandoan	900	-900	0.013000624	0.692257

Source:AEMC, 2022 Integrated System Plan.

Marinus Link 2

Option 1 – Cable 1

- Description – Cable 1:
  - A 750 MW monopole HVDC link between Heybrige (near Brnie) in Tasmania and Latrobe Valley in Victoria
  - Construction on a new 220 kV switching station at Heybridge adjacent to the converter station
  - Establishment of a new 220 kV switching station at Staverton
  - Construction of a new double-circuit 220 kV alternative current (AC) transmission line from Staverton to Heybridge via Hampshire and Burnie
  - Construction of a new double-circuit 220 kV AC transmission line from Palmerston to Sheffield
  - Cut-in both Sheffield-Mersey Forth double circuit 220 kV lines at Staverton
  - A new 500 kV switching station between HVDC converter station and Victorian transmission network in Latrobe Valley
- Status: Actionable
- Additional network capacity (MW):
  - Marinus Link 750 MW in both directions
  - Basslink and Marinus Link VIC to TAS 978 MW, TAS to VIC 1,228 MW, REZ T2 350 MW and T3 450 MW
- Implementation date: July 2029

Option 2 – Cable 2

- Description – Cable 2:
  –
- Status: Actionable
- Additional network capacity (MW):
  – Marinus Link 750 MW in both directions
  – Basslink and Marinus Link VIC to TAS 1,728 MW, TAS to VIC 1,978 MW, REZ T2 800 MW and T3 450 MW
- Implementation date: July 2031

Table 6: Plexos implementation of Marinus Link

Line	Max Flow (MW)	Min Flow (MW)	Resistance (p.u.)	Reactance (p.u.)
Burnie to Sheffield	239.8	-239.8	0.00884	0.04092

Line	Max Flow (MW)	Min Flow (MW)	Loss Base (p.u.)	Loss Increment	Loss Increment 2	Loss Allocation	Marginal Loss Factor	Marginal Loss Factor Back
Burnie to Sheffield	750	-750	4	-0.00392	0.00010393	0.5	0.9789	1

Source: AEMC, 2022 Integrated System Plan

Central West Orana

- Description: New transmission lines connecting to a 500 kV and 330 kV loop in the vicinity of the Central-West Orana REZ indicative location
- Status: Anticipated
- Additional network capacity (MW): 3,000
- Implementation date: 2024

Table 7: Plexos implementation of Central West Orana

Line	Max Flow (MW)	Min Flow (MW)	Resistance (p.u.)	Reactance (p.u.)
Wellington to Wollar 1	1000	-1000	0.004612	0.035225
Wellington to Wollar 2	1000	-1000	0.004612	0.035225
Wellington to Wollar 3	1000	-1000	0.004612	0.035225

Source: AEMC, 2022 Integrated System Plan

New England REZ

Implementaiton date: July 2027

Table 8: Plexos implementation of New England REZ

Line	Max Flow (MW)	Min Flow (MW)	Resistance (p.u.)	Reactance (p.u.)
Armidale to Tamworth	3000	-3000	0.004188	0.03195
Tamworth to Bayswater	3000	-3000	0.004188	0.03195

Source: AEMC, 2022 Integrated System Plan

Darling Downs REZ Expansion

Implementation date: July 2027

Table 9: Plexos implementation of the Darling Downs REZ Expansion

Battery	Capacity (MWh)	Max Power (MW)	Charge efficiency (%)	VO&M ($/MWh)
Darling Downs	100	25	90	1

Line	Max Flow (MW)	Min Flow (MW)	Resistance (p.u.)	Reactance (p.u.)
Halys to Western Downs	2500	-2500	0.00399	0.04636
Halys to Western Downs	2500	-2500	0.00399	0.04636

Source: AEMC, 2022 Integrated System Plan

South East SA REZ Expansion

Implementation date: July 2033

Table 10: Plexos implementation of South East SA REZ Expansion

Line	Max Flow (MW)	Min Flow (MW)	Resistance (p.u.)	Reactance (p.u.)
Tailem Bend to Tungkillo	592.8	-592.8	0.0046	0.0345
	Overload Max Rating (MW)		**Overload Min Rating (MW)**	
	620.35		-620.35	

Source: AEMC, 2022 Integrated System Plan

Gladstone Grid Reinforcement

Implementation date: July 2031

Table 11: Plexos implementation of Gladstone Grid Reinforcement

Line	Max Flow (MW)	Min Flow (MW)	Resistance (p.u.)	Reactance (p.u.)
Bouldercombe to Raglan	725.8	-725.8	0.00329	0.02569
Larcom Creek to Raglan	677.0935	-677.0935	0.00193	0.01508
Calliope River to Larcom	731.4525	-731.4525	0.00117	0.0078
Calvale to Calliope River	550	-550	0.00602	0.05051
	Overload Max Rating (MW)		**Overload Min Rating (MW)**	
Bouldercombe to Raglan	725.8		-725.8	
Larcom Creek to Raglan	677.0935		-677.0935	
Calliope River to Larcom	731.4525		-731.4525	

Source: AEMC, 2022 Integrated System Plan

QNI Connect

Implementation rate: July 2032

Table 12: Plexos implementation of QNI Connect

Line	Max Flow (MW)	Min Flow (MW)	Resistance (p.u.)	Reactance (p.u.)
Braemar to Bulli Creek	1080	-1080	0.00209	0.02489
Dumaresq to Bulli Creek	1080	-1080	0.0036	0.04516
Armidale to Dumaresq	1080	-1080	0.003798	0.04755

Source: AEMC, 2022 Integrated System Plan

Facilities Power to CQ

Implementation date: July 2033

Table 13: Plexos implementation of Facilities Power to CQ

Line	Max Flow (MW)	Min Flow (MW)	Resistance (p.u.)	Reactance (p.u.)
Bouldercombe to Stanwell	885	-885	0.00058	0.00697
Broadsound to Stanwell	885	-885	0.00416	0.05229

Source: AEMC, 2022 Integrated System Plan

Mid North SA REZ

Implementation date: July 2033

Line	Max Flow (MW)	Min Flow (MW)	Resistance (p.u.)	Reactance (p.u.)
Para to Templers West 1	425	-425	0.0025	0.01794
Para to Templers West 2	425	-425	0.0025	0.01794
Templers to Robertstown 1	425	-425	0.005212395	0.037404146
Templers to Robertstown 2	425	-425	0.005212395	0.037404146

Source: AEMC, 2022 Integrated System Plan

South West Victoria REZ Expansion

Implementation date: July 2033

Line (check acronyms)	Max Flow (MW)	Min Flow (MW)	Resistance (p.u.)	Reactance (p.u.)
Mortlake to Moorabool	1500	-1500	0.00121	0.0154
Moorabool to Sydenham	1500	-1500	0.00045	0.00647

Source: AEMC, 2022 Integrated System Plan

S9 Leigh Creek

Line	Max Flow (MW)	Min Flow (MW)	Resistance (p.u.)	Reactance (p.u.)
Davenport to S6	79	-79	0.00041	0.000824