ACIL ALLEN

Default Market Offer 2025-26

LRMC estimates for South Australia

6 March 2025

About ACIL Allen

ACIL Allen is a leading independent economics, policy and strategy advisory firm, dedicated to helping clients solve complex issues.

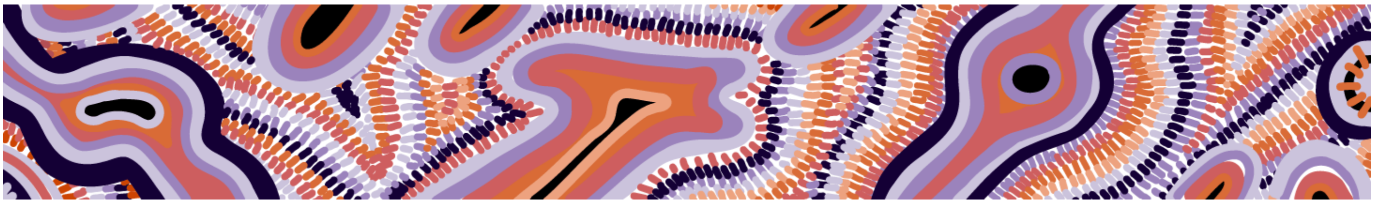
Our purpose is to help clients make informed decisions about complex economic and public policy issues.

Our vision is to be Australia's most trusted economics, policy and strategy advisory firm. We are committed and passionate about providing rigorous independent advice that contributes to a better world.

Report to:

Australian Energy Regulator

ACIL Allen acknowledges Aboriginal and Torres Strait Islander peoples as the Traditional Custodians of the land and its waters. We pay our respects to Elders, past and present, and to the youth, for the future. We extend this to all Aboriginal and Torres Strait Islander peoples reading this report.



Goomup, by Jarni McGuire

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1 Brief

ACIL Allen has been engaged by the Australian Energy Regulator (AER) to support the AER in estimating the wholesale energy cost (WEC) for the determination of Default Market Offer (DMO) prices.

The current approach to estimating the wholesale energy cost (WEC) is a market-based approach, which uses the ASX Energy futures market contract prices and trade volumes as inputs to the estimation of the WEC.

The AER would like to investigate an alternative methodology for estimating the cost for a retailer supplying electricity to residential and small business customers in South Australia (SA).

Therefore, the AER has engaged ACIL Allen to produce an estimate of the long run marginal cost (LRMC) of meeting an incremental increase of system demand in SA.

2 Approach

We have used Plexos to undertake this work, based on the Step Change scenario from the 2024 ISP. From the Plexos modelling we have obtained the hourly LRMCs of meeting an incremental increase of system demand in SA. We then scaled the LRMC to account for the difference in the load shape of the SA system demand (which is what is used in Plexos) and the load shape of the SAPN NSLP and small interval meter import load. We have done this using the brownfield and greenfield approaches.

Therefore, we have provided two LRMC estimates:

1. NSLP + Interval meter load (without exports) – Brownfield
2. NSLP + Interval meter load (without exports) – Greenfield

This briefing note summarises the following:

— The greenfield and brownfield methodologies
— The input assumptions adopted
— The results from the Plexos LRMC modelling
— The methodology to convert the LRMC results from Plexos into LRMCs for the given DMO SA load profiles
— The LRMCs for 2025-26 of the DMO SA load profiles and how these compare with the WECs from the market-based approach.

2.1 LRMC methodologies

We used Plexos to run the Step Change scenario from the 2024 ISP. The modelling was undertaken in long term planning mode. The objective of the model under long-term planning mode is to minimise the net present value of the total costs of the system over a long-term planning horizon. Total costs of the system include new build costs, fixed operation and maintenance costs (FOM), and generation costs (i.e., fuel and variable operation and maintenance costs).

The long-term modelling has been undertaken using a 7-year modelling horizon and 8-hour load blocks per day within the modelling horizon.

From the Plexos modelling we obtained the long-run cost of meeting an incremental increase in electricity demand in SA for each hour under 2 approaches – the Brownfield approach and the Greenfield approach.

Brownfield

Under the Brownfield approach, the existing generator fleet in SA remains in place and the model is run under the Step Change scenario assumptions. This approach considers the existing status of the supply side of the market and then assesses the long run costs of meeting an incremental increase in electricity demand.

This means however, that the capital cost of existing generators is not considered in the LRMC estimate – that is, they are treated as a sunk cost.

The drawback of this approach is that it excludes the capital costs of existing generation capacity. Another drawback to this approach is that it may not represent the most efficient or least cost generation mix to meet demand in this region.

Greenfield

Under the Greenfield approach, the existing generator fleet in SA is 'removed' from the Plexos database in 2025-26 and we allow Plexos to build out generation supply in SA at least cost. Therefore, the capital cost of all generators in SA are included in the LRMC estimate for the Greenfield approach. For this approach the existing generator fleet in the other regions of the NEM remains in place.

The drawback of this approach is that it is an unrealistic representation of the current market.

However, this approach represents an efficient capacity mix over the long-term planning horizon.

While not the focus of this report, neither of the LRMC approaches in our view are the best representation of the cost to a retailer to supplying electricity in SA because they are a theoretical measure of production cost only. The cost of supplying electricity in a given year in each NEM region will be determined not only by production costs but also by market characteristics such as supply and demand, and market concentration.

2.2 Input assumptions

We used the Step Change scenario from the 2024 ISP to undertake this exercise.

The Step Change scenario represents AEMO's Central case for its forecast and planning activities.

A summary of key input assumptions from the Step Change scenario are provide in **Table 2.1**.

Table 2.1 Input assumptions summary – 2024 ISP Step Change scenario

Parameter	Step Change scenario
National Decarbonisation targets	
National Decarbonisation target	At least 43% emissions reduction by 2030. Net zero by 2050.
Demand drivers	
Global economic growth and policy coordination	Moderate economic growth, stronger coordination
Australian economic and demographic drivers	Moderate
Energy Efficiency	Moderate
Consumer engagement e.g. VPP and DSP uptake	High (VPP) and Moderate (DSP)
CER uptake	
CER uptake (i.e. batteries, PV and EVs)	High
Hydrogen and Biomethane	
Hydrogen use	Medium-Low production for domestic use, with minimal export hydrogen.
Hydrogen blending in gas distribution network *	Up to 10% vol
Biomethane/ synthetic methane	Allowed, but no specific targets to introduce it
Scenario alignment	
Global/domestic temperature settings and outcomes	Applies RCP 2.6 where relevant (~ 1.8° C)
IEA 2021 World Energy Outlook scenario	Sustainable Development Scenario (SDS)
Build cost trajectories	
Generator and storage build costs	CSIRO GenCost NZE post 2050
Fuel price settings	
Gas prices	ACIL Allen (2023), Step Change
Coal prices	Wood Mackenzie (2021) & Oxford Economics Australia (2022): Central
Gas Market Settings **	
New gas supplies	As forecast in AEMO's 2023 GSOO
All other gas market settings	Consistent with AEMO's 2023 GSOO Orchestrated Step Change scenario

Source: AEMO

3 Results

Figure 3.1 compares the hourly LRMC on an average time of day (left panel) and distribution curve (right panel) basis in SA in 2025-26 under the Brownfield and Greenfield scenarios.

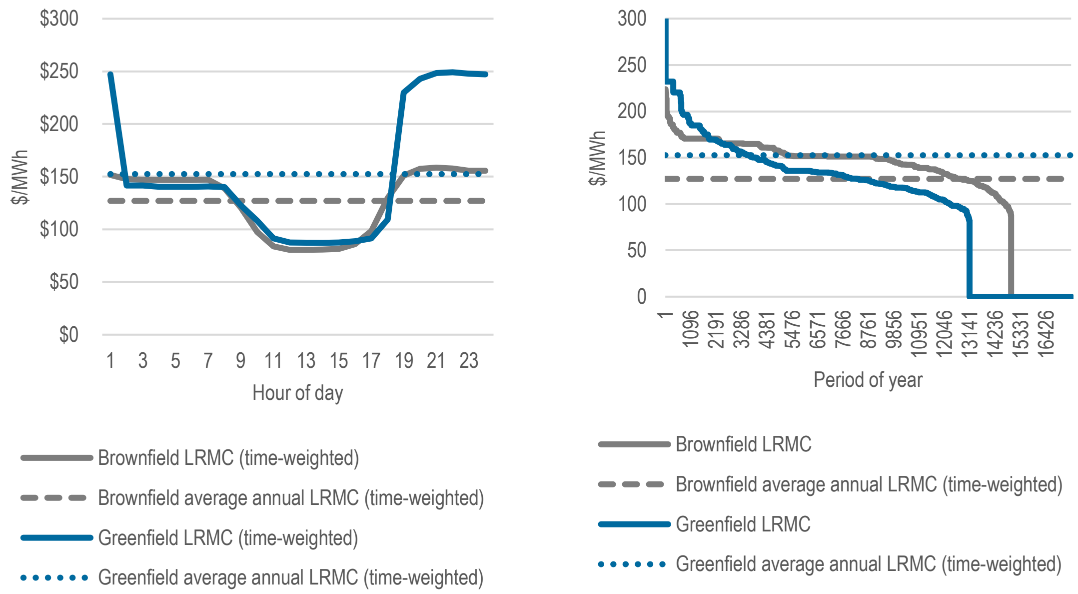
The average LRMC is presented on a time-weighted basis across the financial year 2026. Later in this report we show the LRMC weighted by the SA NSLP.

The LRMC under the Greenfield scenario reflects similar costs production across most periods of the day except for during evening peak periods, when compared with Brownfield scenario. However, during the evening the Greenfield outcomes are noticeably higher. This is due to the model developing a plant build which results in the price reaching the value of customer reliability (VCR) for seven hours on one day in the simulation year - which are valued at about $34,000. This indicates that an incremental MW of load would not be served (i.e. unserved energy (USE) would occur). The model is finding it cheaper to have these seven hours of valued at the VCR rather than build additional capacity for these 7 hours.

It is worth noting that in the LRMC analysis completed for DMO 6[1], the model developed a plant build which resulted in prices at the VCR on a small number of occasions as part of the least cost solution – but these occurred at the *same time of day across a small number of days* – rather than *seven hours on one single day*. This resulted in a much spikier time of day LRMC price profile.

Further, the distribution curves of the LRMC prices have changed noticeably from the DMO 6 analysis. The difference in plant mix will largely be driving this. For example, there is about 1 GW of BESS as part of the least cost solution in the year's analysis – whereas there was about 0.5 GW in the DMO 6 analysis. This difference in plant mix will in part be driven by the inclusion of the Capacity Investment Scheme (CIS) in the latest AEMO Plexos ISP database.

Figure 3.1 LRMC ($/MWh, real 2023) in SA by average time of day (left panel) and distribution curve (right panel) – 2025-26



Source: ACIL Allen modelling

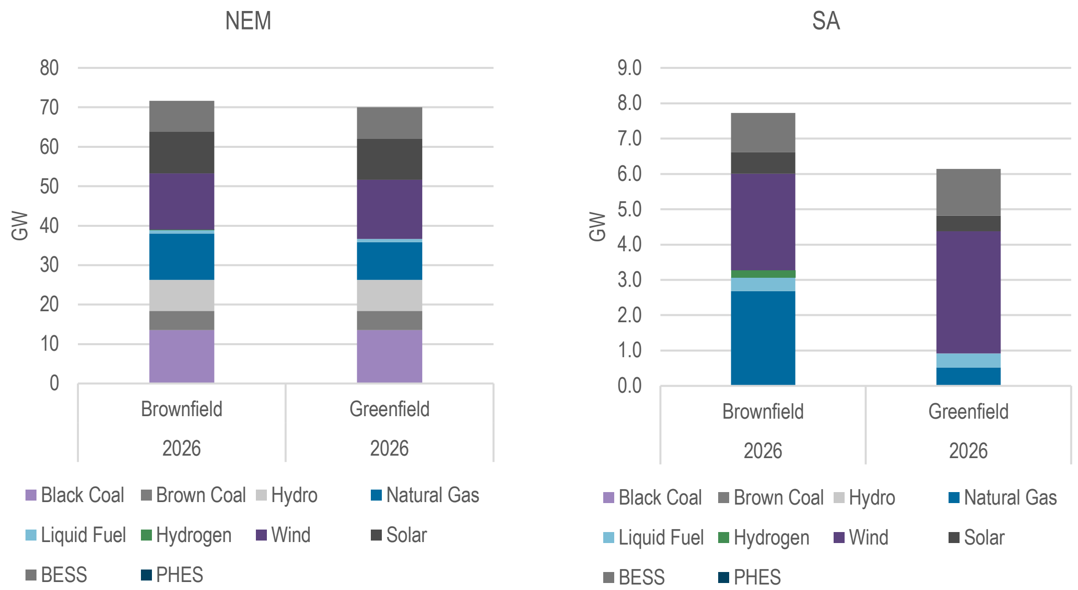
[1] https://www.aer.gov.au/documents/acil-allen-draft-determination-default-market-offer-prices-2024-25-long-run-marginal-cost-estimates-south-australia

Figure 3.2 compares installed capacity by fuel type in 2025-26 under the Brownfield and Greenfield scenarios in the NEM and SA.

There is noticeably less installed capacity in 2025-26 in SA under the Greenfield scenario, which is largely due to the model building less gas fired generation capacity, although there is slightly more wind capacity in the Greenfield scenario. This means that SA is relying more so on imports from Victoria and NSW in the Greenfield scenario during periods of higher demand and/or lower South Australian wind farm output.

Across the NEM the capacity mix is largely the same across both scenarios.

Figure 3.2 Installed capacity (GW) by fuel type in the NEM (left panel) and SA (right panel) – 2025-26

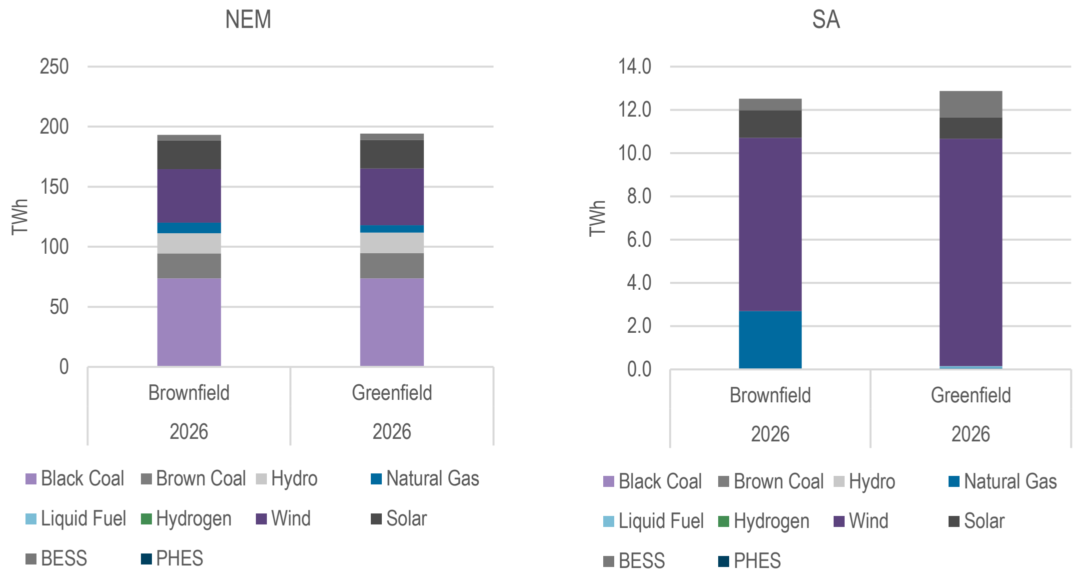


Source: ACIL Allen modelling

Figure 3.3 compares generation mix by fuel type in 2025-26 under the Brownfield and Greenfield scenarios for the NEM and SA. In SA under the Greenfield scenario, there is less generation from gas (-1.7 TWh) which is more than offset by an increase in wind generation.

Across the NEM the generation mix is largely the same across both scenarios.

Figure 3.3 Generation by fuel type (TWh) in the NEM (left panel) and SA (right panel) – 2025-26



Source: ACIL Allen modelling

3.1 Methodology for estimating the WEC using LRMC

We have taken the hourly LRMC values from the Plexos modelling for SA together with the 54 sets of hourly NSLP and interval meter import demand traces (the same set of 54 traces used in the WEC modelling) to calculate the LRMC for each of the 54 sets of NSLP and interval meter import traces. This is done for each of the 54 sets of demands by taking the sum-product of the hourly average time of day LRMCs and NSLP plus interval meter imports and dividing by the sum of the average time of day NSLP and interval meter imports.

The LRMC values produced by Plexos are reported by the model in real 2022-23 dollars, which we have inflated to account for inflation between 2022-23 and 2025-26.

We have then chosen the 75th percentile of the 54 LRMCs.

3.2 LRMC results

The 75th percentile LRMC of the SAPN NSLP and small interval meter imports for 2025-26 is:

— Greenfield: $181.93/MWh

— Brownfield: $142.48/MWh.

This compares with a WEC for the SAPN NSLP and small interval meter imports of $168.52/MWh (based on the trade weighted average contract price up to 13 January 2025). In other words, the WEC sits between the Brownfield and Greenfield LRMCs.

3.3 Summary

The LRMC approach represents the long-run cost of meeting an incremental increase in electricity demand. This approach is not the best representation of the cost to a retailer of supplying electricity in SA because it is a theoretical measure of production cost only.

The cost to a retailer of supplying electricity in any given year will be determined not only by production costs but also by market characteristics such as supply and demand, and market concentration, as well as being influenced by the changing view of the market in the lead up to the year of interest.

Under the Brownfield approach, the LRMC estimate does not represent the cost to a retailer of supplying electricity in SA in 2025-26. This is because the capital costs of existing generators are treated as sunk costs. However, generators enter the market to make a return on investment (whether they achieve this or not depends on how the market plays out over time).

The Greenfield approach is a better representation of the cost to a retailer of supplying electricity in SA because the capital cost of all generators in SA (built efficiently after removing all existing generators in this region) are included in the LRMC estimate. There are some limitations to this approach however, including that the most efficient build of generation capacity does not represent the existing supply mix, which may be less efficient or more costly.

Appendices

A Model

A.1 Plexos

Plexos is a globally recognised energy market simulation engine providing analytics and decision-support to modelers, generators, and market analysts— offering flexible and precise simulations across electric, water, gas and renewable energy markets.

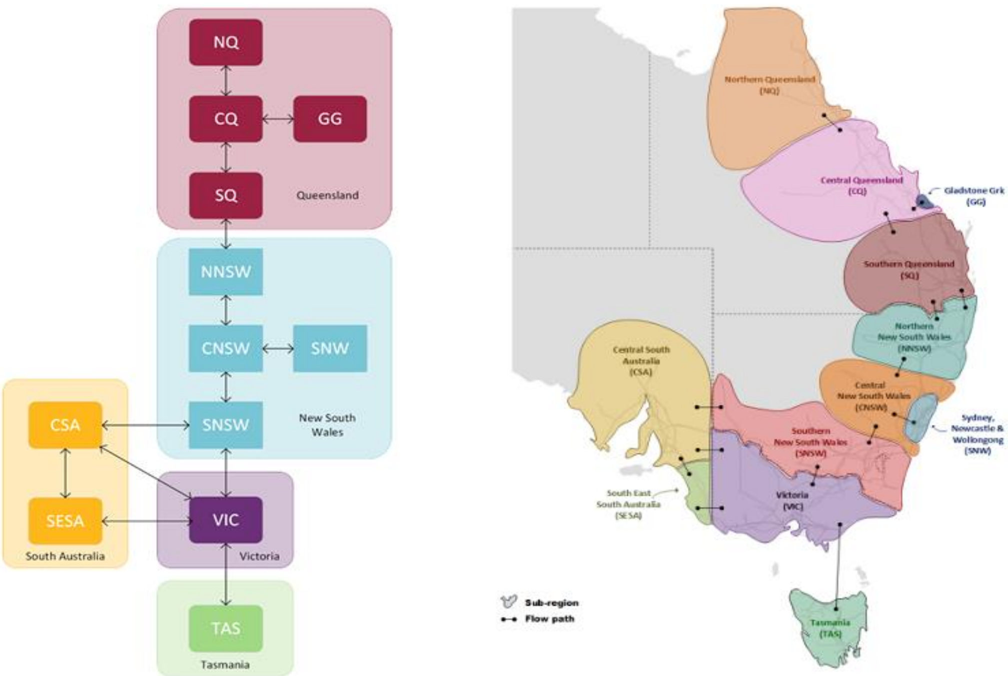
ACIL Allen utilises the Plexos modelling platform where least cost planning approaches to modelling are required. This work often draws from the Plexos database published by AEMO as part of the Integrated System Plan (ISP). This dataset forms the basis for the detailed long-term (DLT) planning component of the ISP and has been used in the past as the basis for RIT-T assessments.

The DLT divides the modelling horizon into multiple steps (four, seven-year blocks) which are optimised sequentially. The shorter optimisation windows allow a chronological optimisation of each day of the modelling horizon that preserves the original chronology of the demand and renewable resource time series, ensuring a more detailed representation of demand and VRE variability. Demand and VRE profiles are represented using a fitted chronology.

The DLT utilises a sub-regional representation of the NEM as shown in **Figure A.1** to better reflect current and emerging intra-regional transmission limitations.

A full description of the ISP methodology is available here: https://aemo.com.au/en/energy-systems/major-publications/integrated-system-plan-isp/2024-integrated-system-plan-isp/isp-methodology

Figure A.1 NEM topology as modelled by AEMO in the ISP



Source: AEMO ISP Methodology paper June 2023

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