



Department of
**Energy and Economic
Diversification**

FESO 2027 Capacity expansion and dispatch modelling methodology

Appendix B



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1. Long-term capacity expansion modelling methodology

1.1. Overview

The long-term capacity expansion model (LT model) identifies the least-cost pathway for generation, storage, and transmission investments required to meet electricity demand whilst achieving decarbonisation objectives. The model uses mathematical optimisation to solve for the lowest-cost combination of investment and high-level operational decisions that satisfies physical and economic system requirements.



Long-term capacity expansion modelling will be conducted in PLEXOS, an energy market modelling platform used across industry, including AEMO and other jurisdictional planning bodies. PLEXOS enables economic, policy and technical constraints to be overlaid on the modelling of electricity capacity expansion and dispatch. It also allows optimisation parameters, such as temporal granularity and length of study period, to be tailored to the planning question.

1.2. Inputs

The long-term model takes various inputs representing the current and future electricity system including, but not limited to, existing generation parameters, current and future network constraints, demand projections, and capital cost forecasts. Full modelling assumptions are defined in the Draft 2027 FESO I&A workbook, but we have listed some important inputs in the table below.

Input	Description
Demand traces and peak demand	Half-hourly operational demand traces including the impact of CER (rooftop PV, behind-the-meter storage) and electrification provided by Western Power.
Renewable traces	Half-hourly traces for wind and utility solar using the synthetic weather reference year provided by Western Power.
Coal retirements	Announced State-owned and private coal retirement dates.
Existing and committed generation	Existing and committed generation parameters including capacity, duration, heat rates, round trip efficiency provided by market participants.

Input	Description
Capacity build limits	Maximum build quantities by technology, zone and year, reflecting land use, resource quality, social licence, supply chain and connection constraints.
Cost assumptions	Capital costs (with technology learning curves), connection costs, fixed and variable O&M, fuel prices and discount rate (WACC).
Forced outage rates	Full and partial forced outage rates and maintenance rates by facility class, applied as capacity derating in the long-term model.
Gas supply constraints	Gas pipeline flow and storage constraints to reflect limitations that impact GPG operations. The impact of non-GPG gas demand on leftover transport capacity for GPG is taken as a fixed input assumption.
State and Federal policies	Net zero 2050 decarbonisation constraint applied as part of the optimisation.
Transmission	Transmission network flow limits from Western Power
Transmission pathway	Committed and anticipated augmentations are fixed; candidate augmentations are co-optimised and determined by the model.
RCM settings	Reserve Capacity Target formulation, capacity credit assignment methodology by Capability Class, and ESR duration requirements.

1.3. Optimisation target

The capacity expansion model determines the investment pathway and high-level operational decisions that minimise the net present value of total costs over a 24-year planning horizon, subject to constraints. Total system cost comprises annualised capital costs of new generation, storage and transmission, fixed and variable operating costs and fuel costs.

The optimisation seeks the point at which additional capital expenditure is balanced against the avoided costs of generation, fuel, and load shedding. Therefore, the model also solves for least-cost generation but at lower temporal resolution than in the subsequent short-term dispatch modelling to determine detailed operational decisions and price outcomes. The temporal granularity in capacity expansion modelling must be sufficient to capture diurnal and seasonal patterns in demand and renewable output relevant to investment decisions.

1.4. Constraints

The least-cost pathway is determined subject to a series of requirements or 'constraints' which can represent the physical or economic characteristics of the system including:

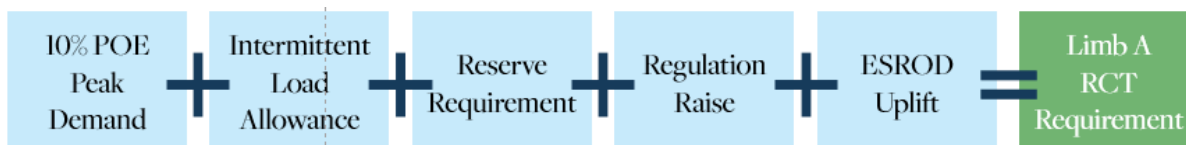
- Energy balance – supply must meet demand in all intervals;
- Facility constraints – plant capacities and storage duration, ramp rates, minimum stable levels, and outage-derated availability;
- Network constraints – inter-zonal transfer limits. More detailed constraint equations are reflected in the short-term dispatch modelling;
- Fuel constraints – gas pipeline flow and linepack constraints to reflect limitations that impact GPG operations.

- Policy constraints – decarbonisation targets;
- Build constraints – capacity build limits by technology, zone and year, and fixed coal retirement dates;
- Reliability and system security constraints – the Reserve Capacity Target and high-level security constraints.

1.5. Reserve Capacity Target

Investment adequacy in the WEM is underpinned by the Reserve Capacity Mechanism (RCM) and represented in the long-term model with a reserve capacity target (RCT). The RCT is developed and applied in each year of the modelling period to meet the reliability and reserve requirements set out in the ESM rules.

The first LT modelling iteration focuses on Limb A of the Planning Criterion, comprising the 10% POE peak demand forecast, plus the intermittent load allowance, reserve requirement, regulation raise requirement and ESROD uplift, as illustrated in the figure.



Subsequent LT modelling iterations will include Limb B informed by short-term dispatch and reliability modelling. The higher of the two limbs sets the RCT, which is a planning reserve margin that must be met in each year of the horizon. Facilities contribute to this margin through capacity credits assigned by Capability Class, as determined by AEMO. For each technology class, the model applies the average capacity credits of existing facilities to future years. New storage facilities are assigned capacity credits according to the ESROD, and new thermal facilities receive their full capacity while renewables receive a percentage that is approximate to their output.

1.6. Transmission

The SWIS is represented by 25 zones in the long-term model, with intra-zonal networks aggregated and inter-zonal transfer capability represented through transmission flows. This balances locational fidelity against tractability over a multi-decade horizon. Demand and supply are also represented by these 25 zones.

The model identifies the optimal transmission development pathway, which is a sequence of transmission investments in which the timing and sizing of projects maximise net economic benefit. While asset utilisation can be an indicative measure, this metric alone does not capture economic value: an augmentation with low annual utilisation can still provide high value where it avoids unserved energy or defers expensive generation investment. The techno-economic optimum is therefore the sequence of transmission projects that minimises the NPV of total system cost of meeting demand and policy objectives. In doing so, the model finds the “sweet spot” between additional transmission expenditure and reduced generation and load-shedding costs.

1.7. Outputs

The long-term capacity expansion identifies what new investments are required to meet future demand at least cost for a given set of input assumptions. Given the high levels of uncertainty about the future as the energy transition progresses, this analysis is repeated across a range of scenarios that reflect different views or states of the world. Its principal outputs are:

- **Capacity build schedule** – new entrant capacity by technology, zone and year, together with economic retirements;
- **Transmission development pathway** – the timing, location and sizing of network augmentations within the co-optimised plan.
- **Generation mix** – high level generation and dispatch decisions.
- **System cost** – annuitized build & FO&M costs for new generators, batteries and network augmentations; fuel and VO&M costs for generators.
- **RCM outcomes** – the Reserve Capacity Target.

Collectively, these outputs form a set of least-cost development pathways that provide a reference point for future system planning and investment decision-making. The capacity expansion plan and transmission build path are passed to the more detailed dispatch model, which validates operational feasibility and performance at half-hourly granularity and provides the interface with detailed power system modelling. Where the validation identifies material issues, results are iterated back into the long-term stages.

2. Short-term dispatch modelling methodology

2.1. Overview

Short-term (ST) dispatch modelling takes the development pathway defined by the long-term capacity expansion model and simulates the operation of the electricity system in more detail. Rather than optimising investment, the ST model takes the capacity build schedule and transmission development pathway identified by the capacity expansion model as a fixed input and determines the least-cost dispatch of electricity required to meet demand, plant availability and technical constraints in every interval over the planning horizon. In essence, it aims to replicate the WEM dispatch engine (WEMDE) by optimising dispatch based on participant bids.

The ST model includes more temporal and technical granularity than the capacity expansion model. Temporally, it sequentially solves every half-hour interval for the entire 24-year horizon rather than sampling specific days at hourly resolution or otherwise reducing temporal granularity as in the LT. The ST model also incorporates more detailed representation of network constraints, plant operating characteristics (including heat rates or must-run constraints) and storage behaviour than is tractable at the capacity expansion stage.

In this methodology, short-term modelling serves two purposes: first, as a validation tool, testing the operational feasibility and reliability of the investment pathway determined by the capacity expansion model; and second, to determine pricing and revenue adequacy outcomes. Where validation identifies material issues with the capacity expansion investment pathway, results are iterated back into the long-term modelling stage. More detail on reliability and revenue adequacy modelling can be found in sections 3 and 4.

2.2. Inputs

The dispatch model uses similar inputs to the long-term model but with some differences to represent the system at a higher fidelity. It takes the development pathway from the capacity expansion model as fixed, together with additional operational parameters and participant bids. The Draft 2027 FESO I&A workbook defines the full modelling assumptions, but we have listed some key inputs in the table below.

Input	Description
Demand traces and peak demand	Half-hourly operational demand traces including the impact of CER (rooftop PV, behind-the-meter storage) and electrification provided by Western Power.
Renewable traces	Half-hourly traces for wind and utility solar using the synthetic weather reference year provided by Western Power.
Capacity build and retirement schedule	As defined by the capacity expansion model.
Transmission expansion pathway	The timing, location and sizing of network augmentations determined by the capacity expansion model.
Plant operational parameters	Operational parameters such as capacity, duration, round trip efficiency, degradation, heat rates, ramp rates, minimum stable levels.

Input	Description
Generator bids	Generator bids represented as their short-term marginal costs to set the merit order for dispatch
Forced outage rates	Synthetic outage traces will be developed for reliability modelling
Gas supply constraints	Gas pipeline transport constraints and linepack storage to reflect limitations that impact GPG operations.
State and Federal policies	Net zero 2050 decarbonisation constraint applied as part of the optimisation.
Transmission	Transmission network flow limits from Western Power

2.3. Optimisation target

The short-term model uses the development pathway determined in the capacity expansion modelling to dispatch the market according to generators' bids, network constraints, demand, storage levels and other technical constraints. The ST model uses optimisation to determine the least-cost economic dispatch of electricity to meet demand in every half-hourly interval over the 24-year planning horizon.

Generating units are dispatched in merit order according to their SRMC-based bid, and the model solves for the dispatch and storage operation pattern that minimises total system operating cost in each interval, subject to the constraints outlined in the following section.

2.4. Constraints

The least-cost dispatch is determined subject to a series of constraints representing the physical and economic characteristics of the system, including:

- Energy balance – supply must meet demand in every interval;
- Facility operational and availability constraints – for instance, but not limited to plant capacities, ramp rates, minimum stable levels, and outage-derated availability;
- Network constraints – detailed inter- and intra-zonal transfer limits;
- Fuel constraints – fuel availability limits, consistent with the capacity expansion model; and
- Storage constraints – state-of-charge continuity and cycling limits.

2.5. Outputs

The short-term dispatch model projects future prices, generation, network flow and unserved energy outcomes at high fidelity. Its principal outputs are:

- Price outcomes – Real-Time Market (RTM) price;
- Dispatch outcomes – generation dispatch by unit (generator or battery);
- Network flows;
- Unserved energy (USE);

- Emissions; and
- Fuel offtake.

These principal outputs, among others, are combined and interpreted for the purposes of reliability, commerciality and price modelling as described in the subsequent sections.

3. Commerciality assessment

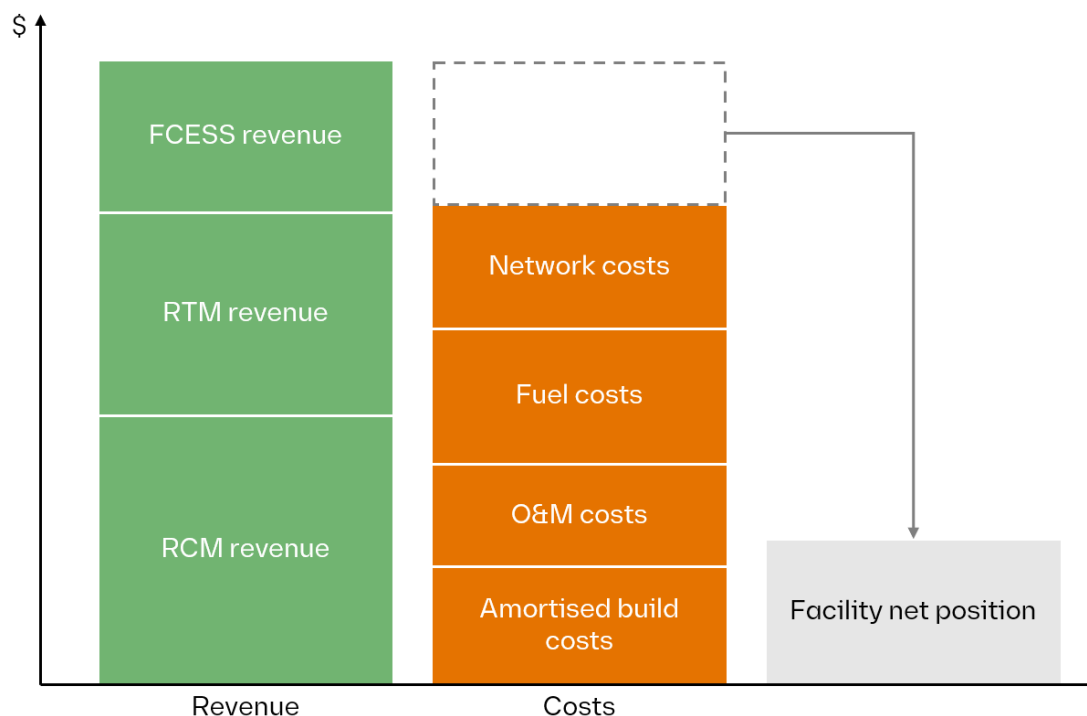
3.1. Overview

The commerciality assessment determines whether investors would build the development pathway identified in the long-term capacity expansion and dispatch least cost modelling. This tests if the facilities within the system can earn enough from the market to justify the costs committed to them.

An important note is that revenue adequacy cannot be inferred from the capacity expansion modelling alone. Realised revenue can depart from the implied cost recovery in the long-term capacity expansion modelling due to additional operational and network constraints, curtailment, and storage state-of-charge outcomes produced in the dispatch model. Therefore, it is important to assess revenue sufficiency so the FESO produces a development path that existing and new participants want to invest in and can operate profitably. If revenue shortfalls emerge ('missing money'), the market may not deliver the required pathway to achieve the transition, which may prompt policy development and further analysis.

3.2. Approach

The commerciality of each facility will be assessed by comparing projected revenue with total costs to determine the facility's net position, as shown in the figure below. This assessment will be completed at the individual level, allowing the study to identify which technologies are commercially viable under current market settings and which would require additional mechanisms or incentives to be developed. Certain inputs and outcomes from the least-cost capacity expansion and dispatch modelling are used to create the revenue and cost stacks.



Stack component	Source and treatment
RTM revenue	Half-hourly sent-out generation multiplied by the RTM price, taken directly from the short-term dispatch simulations, with loss factors applied consistently with the dispatch model. Storage is settled on both charge and discharge.
FCESS revenue	Revenue from frequency co-optimised essential system services — Regulation Raise and Lower, Contingency Reserve Raise and Lower, and RoCoF Control Service — where these are represented in the dispatch model. NCESS is excluded.
RCM revenue	Taken from the long-term capacity expansion model, which determines the Reserve Capacity Target and the indicative Reserve Capacity Price trajectory for each Capacity Year. Facility revenue is the Capacity Credits assigned to the facility multiplied by that price, with Capacity Credit assignment by Capability Class and ESR Duration Requirement treatment following the RCM methodology.
Amortised build costs	Capital costs are annuitised over the facility's economic life using the capital cost trajectory (including technology learning curves), connection cost and the WACC applied in the capacity expansion model, so that cost recovery is tested against the same cost basis used to build the pathway.
O&M costs	Fixed O&M per MW per annum and variable O&M per MWh of sent-out generation, together with start costs where unit commitment is represented, and storage degradation and augmentation cost over asset life.
Fuel costs	Fuel offtake from the dispatch solution, using facility heat rates and the scenario fuel price trajectory, including gas transport cost consistent with the gas supply constraints applied in the dispatch model.
Network costs	Network charges facing the facility, consistent with the network cost inputs provided by Western Power and with the network component of the delivered cost stack.

We do not consider other sources of revenue from bilateral contracts, hedging, certificates, and network support agreements, so results reflect only a market-revenue perspective, which is conservative and understates the revenue certainty a contracted facility would experience.

3.3. Outputs

The net position, total revenue less total costs, will determine if the facility can operate profitably in the market for each year and is interpreted as follows:

- **If the net position is greater than zero** — the facility is able to recover its costs through existing market revenue streams; and
- **If the net position is less than zero** — the facility is not able to recover its costs through existing market revenue streams and is unlikely to be developed without an additional mechanism or payment.

This will provide insight into the facilities and archetypes at risk, such as those with persistent negative net positions. It will also identify the causes and use them to inform policy development. Supporting outputs include detailed facility-level revenue and cost build-ups across tested scenarios. Together, these outputs test the least-cost pathway against the commercial reality required to deliver it.

4. Pricing and cost methodology

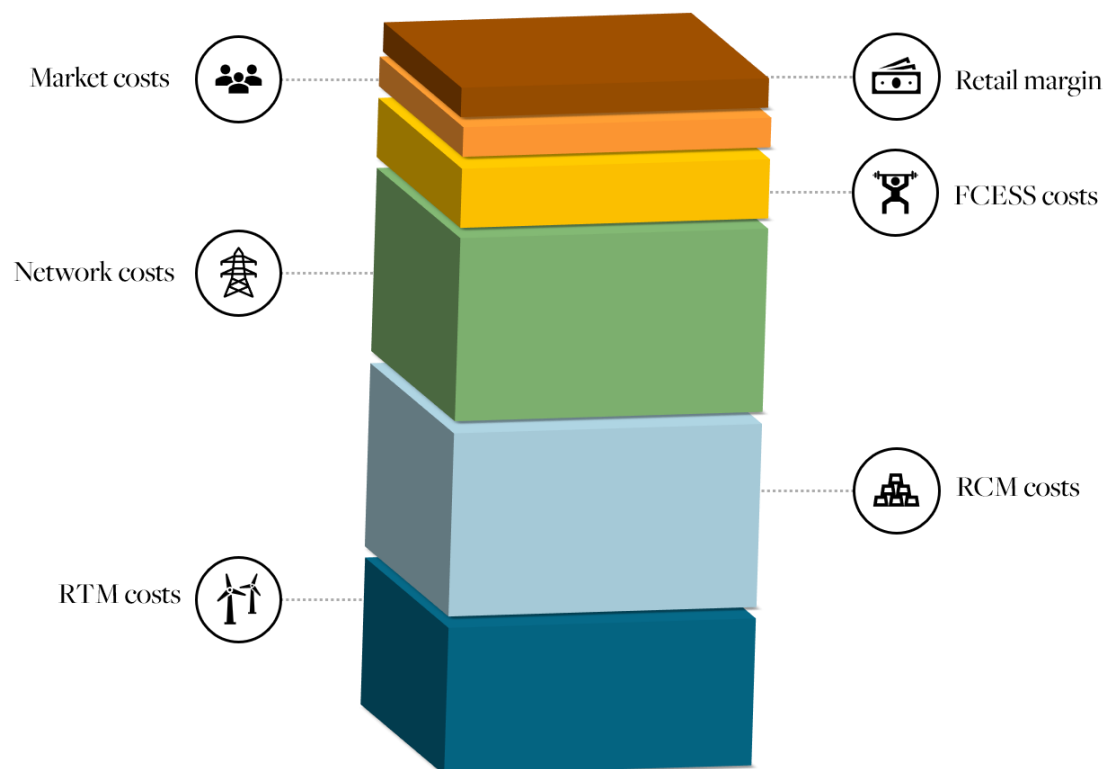
4.1. Overview

The FESO will also investigate the total costs of delivering the optimal development pathway to consumers and how those costs change over time. This analysis will help inform potential customer bills and, where regulated tariffs are held below the cost of supply, government subsidy payments.

Two pathways can be close in net present value terms and still produce materially different trajectories of delivered cost per MWh. They may differ when capital is committed, how much of the cost sits in the network rather than in generation, and how tightly the market prices scarcity. Making that trajectory visible, and identifying which component drives it, allows the FESO to inform decisions on affordability and on the fiscal exposure that follows from holding tariffs at their current level, alongside the investment and reliability questions.

4.2. Approach

Modelling inputs and outputs will be combined to develop a bottom-up cost stack which will be used to analyse end-to-end energy costs. The cost stack comprises six components, including RCM, RTM, FCESS, network and market costs and a retailer margin, as represented in the diagram below.



The derivation of each component of the cost stack is set out in the table below.

Stack component	Derivation and treatment
RTM costs	Derived directly from the pricing and dispatch outcomes of the short-term modelling. Energy consumed in the SWIS is settled at the half-hourly RTM price.
RCM costs	The Reserve Capacity Price is calculated using the BRCP forecast and the reserve capacity balance output by the capacity expansion model. Total RCM cost is that price multiplied by the Capacity Credit allocation forecast, accounting for transmission pricing, the ESR Duration Requirement and other relevant market settings.
FCESS costs	FCESS costs are derived directly from the shadow prices on the reserve constraints in the ST dispatch model. The shadow price on each constraint is the marginal cost of meeting that requirement in the interval, which is the price the service would clear at and multiplying it by the quantity enabled gives the cost of each service.
Network costs – transmission	Transmission costs will be extrapolated based on the latest Access Arrangement methodology, so revenue is built up from the regulated building blocks (return on the asset base, depreciation, operating and maintenance costs and tax). Operating and maintenance costs are projected forward, and expansion costs will be informed by Western Power. Augmentation enters the asset base as projects are commissioned and is recovered over the asset life, so the investment cost is spread over the years consumers would bear it.
Network costs – distribution	Distribution tariffs are escalated in line with forecast DER uptake, recognising that distribution costs are driven less by bulk energy volumes than by the network's exposure to DER, which alters peak and minimum flows.
Market costs	AEMO market fees and regulatory levies recovered from market participants, informed by AEMO and escalated across the horizon.
Retail margin	The retail margin will be a percentage uplift of the total cost stack to account for expenditure associated with acquiring customers, billing and call centres.

4.3. Outputs

The cost stack answers what the development pathway costs to deliver, how that cost evolves over the 24-year modelling horizon, and which components drive it. It will include the following outputs:

- **Total delivered cost stack** — \$/MWh and aggregate dollars by year and scenario, decomposed into RTM, RCM, FCESS, transmission, distribution and market cost components;
- **Component trajectories** — each component reported separately over time;
- **Bill and subsidy indicators** — delivered cost against prevailing regulated tariff levels indexed to CPI, indicating the implications for customer bills and for the subsidy payments required to maintain them.

Together, these outputs place the affordability consequences of each development pathway alongside reliability and commerciality implications, so the trade-offs are known and investment decisions can be guided by a holistic view of each workstream.