Appendix I: PCF Model

In the PCF Model, prices and costs increase annually by a forecast general inflation rate (CPI).

$$\pi_j^{R,C} = \left[1 + \left(\frac{CPI}{100}\right)\right]^j , \quad (1)$$

Energy output q_j^i from each plant (*i*) in each period (*j*) is a key variable in driving revenue streams, unit fuel costs, fixed and variable Operations & Maintenance costs. Energy output is calculated by reference to installed capacity k^i, capacity utilisation rate CF_j^i for each period *j*. Plant auxiliary losses Aux^i arising from on-site electrical loads are deducted. Plant output is measured at the Node and thus a Marginal Loss Factor MLF^i coefficient is applied.

$$q_j^i = CF_j^i . k^i . (1 - Aux^i). MLF^i, \quad (2)$$

A convergent electricity price for the *i*th plant $(p^{i\varepsilon})$ is calculated in year one and escalated per Eq. (1). Thus, revenue for the *i*th plant in each period *j* is defined as follows:

$$R_j^i = (q_j^i . p^{i\varepsilon} . \pi_j^R), \quad (3)$$

If thermal plants are to be modelled, marginal running costs need to be defined per Eq. (4). The thermal efficiency for each generation technology ζ^i is defined. The constant term '3600'[1] is divided by ζ^i to convert the efficiency result from % to kJ/kWh. This is then multiplied by raw fuel commodity cost f^i. Variable Operations & Maintenance costs v^i, where relevant, are added which produces a pre-carbon short run marginal cost.

Under conditions of externality pricing CP_j, the CO_2 intensity of output needs to be defined. Plant carbon intensity g^i is derived by multiplying the plant heat rate by combustion emissions $\dot{g}^i$ and fugitive CO_2 emissions $\hat{g}^i$. Marginal running costs in the *j*th period is then calculated by the product of short run marginal production costs by generation output q_j^i and escalated at the rate of π_j^C.

$$\vartheta_j^i = \left\{ \left[\left(\frac{\left(3600/\zeta^i\right)}{1000} . f^i + v^i \right) + \left(g^i . CP_j \right) \right] . q_j^i . \pi_j^C \middle| g^i = \left(\dot{g}^i + \hat{g}^i \right) . \frac{\left(3600/\zeta^i\right)}{1000} \right\}, \quad (4)$$

Fixed Operations & Maintenance costs FOM_j^i of the plant are measured in \$/MW/year of installed capacity FC^i and are multiplied by plant capacity k^i and escalated.

$$FOM_j^i = FC^i . k^i . \pi_j^C , \quad (5)$$

Earnings Before Interest Tax Depreciation and Amortisation (EBITDA) in the *j*th period can therefore be defined as follows:

$$EBITDA_j^i = \left(R_j^i - \vartheta_j^i - FOM_j^i \right), \quad (6)$$

[1] The derivation of the constant term 3,600 is: 1 Watt = 1 Joule per second and hence 1 Watt Hour = 3,600 Joules.

Capital Costs $\left(X_0^i\right)$ for each plant *i* are Overnight Capital Costs and incurred in year 0. Ongoing capital spending $\left(x_j^i\right)$ for each period *j* is determined as the inflated annual assumed capital works program.

$$x_j^i = c_j^i . \pi_j^C, \tag{7}$$

Plant capital costs X_0^i give rise to tax depreciation $\left(d_j^i\right)$ such that if the current period was greater than the plant life under taxation law (*L*), then the value is 0. In addition, x_j^i also gives rise to tax depreciation such that:

$$d_j^i = \left(\frac{X_0^i}{L}\right) + \left(\frac{x_j^i}{L-(j-1)}\right), \tag{8}$$

From here, taxation payable $\left(\tau_j^i\right)$ at the corporate taxation rate $\left(\tau_c\right)$ is applied to $EBITDA_j^i$ less Interest on Loans $\left(I_j^i\right)$ later defined in (16), less d_j^i. To the extent $\left(\tau_j^i\right)$ results in non-positive outcome, tax losses $\left(L_j^i\right)$ are carried forward and offset against future periods.

$$\tau_j^i = Max\left(0, \left(EBITDA_j^i - I_j^i - d_j^i - L_{j-1}^i\right). \tau_c\right), \tag{9}$$

$$L_j^i = Min\left(0, \left(EBITDA_j^i - I_j^i - d_j^i - L_{j-1}^i\right). \tau_c\right), \tag{10}$$

The debt financing model computes interest and principal repayments on different debt facilities depending on the type, structure and tenor of tranches. There are two types of debt facilities – (a) corporate facilities (i.e. balance-sheet financings) and (2) project financings. Debt structures available in the model include bullet facilities and semi-permanent amortising facilities (Term Loan B and Term Loan A, respectively).

Corporate Finance typically involves 5- and 7-year bond issues with an implied 'BBB' credit rating. Project Finance include a 5-year Bullet facility requiring interest-only payments after which it is refinanced with consecutive amortising facilities and fully amortised over an 18-25 year period (depending on the technology) and a second facility commencing with tenors of 5-12 years as an Amortising facility set within a semi-permanent structure with a nominal repayment term of 18-25 years.

The decision tree for the two Term Loans was the same, so for the Debt where DT = 1 or 2, the calculation is as follows:

$$if\ j \begin{cases} > 1, DT_j^i = DT_{j-1}^i - P_{j-1}^i \\ = 1, DT_1^i = D_0^i . S \end{cases} \tag{11}$$

D_0^i refers to the total amount of debt used in the project. The split (*S*) of the debt between each facility refers to the manner in which debt is apportioned to each Term Loan facility or Corporate Bond. In most model cases, 35% of debt is assigned to Term Loan B and the remainder to Term Loan A. Principal P_{j-1}^i refers to the amount of principal repayment for tranche *T* in period *j* and is calculated as an annuity:

$$P_j^i = \left(\frac{DT_j^i}{\left[\frac{1-(1+(R_{Tj}^z + C_{Tj}^z))^{-n}}{R_{Tj}^z + C_{Tj}^z} \right]} \middle| z \begin{cases} = VI \\ = PF \end{cases} \right) \quad (12)$$

In (12), R_{Tj} is the relevant interest rate swap (5yr, 7yr or 12yr) and C_{Tj} is the credit spread or margin relevant to the issued Term Loan or Corporate Bond. The relevant interest payment in the *j*[th] period (I_j^i) is calculated as the product of the (fixed) interest rate on the loan or Bond by the amount of loan outstanding:

$$I_j^i = DT_j^i \times (R_{Tj}^z + C_{Tj}^z) \quad (13)$$

Total Debt outstanding D_j^i, total Interest I_j^i and total Principle P_j^i for the *i*[th] plant is calculated as the sum of the above components for the two debt facilities in time *j*. For clarity, Loan Drawings are equal to D_0^i in year 1 as part of the initial financing and are otherwise 0.

One of the key calculations is the initial derivation of D_0^i (as per eq.11). This is determined by the product of the gearing level and the Overnight Capital Cost (X_0^i). Gearing levels are formed by applying a cash flow constraint based on credit metrics applied by project banks and capital markets. The variable γ in our PF Model relates specifically to the legal structure of the business and the credible capital structure achievable. The two relevant legal structures are Vertically Integrated (VI) merchant utilities (issuing 'BBB' rated bonds) and Independent Power Producers using Project Finance (PF).

$$iif\ \gamma \begin{cases} = VI,\ \frac{FFO_j^i}{I_j^i} \geq \delta_j^{VI} \forall\ j \left| \frac{D_j^i}{EBITDA_j^i} \geq \omega_j^{VI} \forall\ j \right| FFO_j^i = (EBITDA_j^i - x_j^i) \\ = PF, Min(DSCR_j^i, LLCR_j^i) \geq \delta_j^{PF}, \forall\ j \left| DSCR_j = \frac{(EBITDA_j^i - x_j^i - \tau_j^i)}{P_j^i + I_j^i} \right| LLCR_j = \frac{\sum_{j=1}^{N} \left[(EBITDA_j^i - x_j^i - \tau_j^i).(1+K_d)^{-j} \right]}{D_j^i} \end{cases} \quad (14)$$

Credit metrics[2] (δ_j^{VI}) and (ω_j^{VI}) are exogenously determined by credit rating agencies and are outlined in Table 2. Values for δ_j^{PF} are exogenously determined by project banks and depend on technology (i.e. thermal vs. renewable) and the extent of energy market exposure, that is whether a Power Purchase Agreement exists or not. For clarity, FFO_j^i is 'Funds From Operations' while $DSCR_j^i$ and $LLCR_j^i$ are the Debt Service Cover Ratio and Loan Life Cover Ratios. Debt drawn is:

$$D_0^i = X_0^i - \sum_{j=1}^{N} \left[EBITDA_j^i - I_j^i - P_j^i - \tau_j^i \right].(1+K_e)^{-(j)} - \sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)} \quad (15)$$

Relevant rates and associated credit metrics appear in Table A1.

---

[2] For Balance Sheet Financings, Funds From Operations over Interest, and Net Debt to EBITDA respectively. For Project Financings, Debt Service Cover Ratio and Loan Life Cover Ratio.

Table A1 – Interest Rates, Equity Returns and Credit Metrics

Project Finance		100% PPA	75% PPA
Debt Sizing Constraints			
- DSCR	(times)	1.25	1.39
- Gearing Limit	(%)	80%	70%
- Default	(times)	1.05	1.05
PF Facilities - Tenor			
- Term Loan B (Bullet)	(Yrs)	5	5
- Term Loan A (Amortising)	(Yrs)	7	7
PF Facilities - Pricing			
- Term Loan B Swap	(%)	4.11%	4.11%
- Term Loan B PF Spread	(bps)	180	195
- Term Loan A Swap	(%)	4.21%	4.21%
- Term Loan A PF Spread	(bps)	209	229
- Refinancing Rate	(%)	6.16%	6.31%
Expected Equity Returns	(%)	9.0%	9.5%

Balance Sheet		
Credit Metrics (BBB Corporate)		VI* Utility
- FFO / I	(times)	4.2
- Gearing Limit	(%)	40.0
- FFO / Debt	(%)	20%
Bond Issues		
- 5 Year	(%)	5.43%
- 7 Year	(%)	5.58%
- 10 Year	(%)	5.68%
Commonwealth Bonds		
- 10 Year	(%)	4.21%
Expected Equity Returns	(%)	10.0%

* Vertically Integrated, BBB Rated

At this point, all of the necessary conditions exist to produce estimates of the long run marginal cost of power generation technologies along with relevant equations to solve for the price $(p^{i\varepsilon})$ given expected equity returns (K_e) whilst simultaneously meeting the constraints of δ_j^{VI} and ω_j^{VI} or δ_j^{PF} given the relevant business combinations. The primary objective is to expand every term which contains $p^{i\varepsilon}$. Expansion of the EBITDA and Tax terms is as follows:

$$0 = -X_0^i + \sum_{j=1}^{N}\left[\left(p^{i\varepsilon}.q_j^i.\pi_j^R\right) - \vartheta_j^i - FOM_j^i - I_j^i - P_j^i - \left(\left(p^{i\varepsilon}.q_j^i.\pi_j^R\right) - \vartheta_j^i - FOM_j^i - I_j^i - d_j^i - L_{j-1}^i\right).\tau_c\right].(1+K_e)^{-(j)} - \sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)} - D_0^i \qquad (16)$$

The terms are then rearranged such that only the $p^{i\varepsilon}$ term is on the left-hand side of the equation:

Let $IRR \equiv K_e$

$$\sum_{j=1}^{N}(1-\tau_c).p^{i\varepsilon}.q_j^i.\pi_j^R.(1+K_e)^{-(j)} = X_0^i - \sum_{j=1}^{N}\left[-(1-\tau_c).\vartheta_j^i - (1-\tau_c).FOM_j^i - (1-\tau_c).\left(I_j^i\right) - P_j^i + \tau_c.d_j^i + \tau_c L_{j-1}^i).(1+K_e)^{-(j)}\right] + \sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)} + D_0^i \qquad (17)$$

The model then solves for $p^{i\varepsilon}$ such that:

$$p^{i\varepsilon} = \frac{X_0^i}{\sum_{j=1}^{N}(1-\tau_c).P^{\varepsilon}.\pi_j^R.(1+K_e)^{-(j)}} + \frac{\sum_{j=1}^{N}\left((1-\tau_c).\vartheta_j^i + (1-\tau_c).FOM_j^i + (1-\tau_c).\left(I_j^i\right) + P_j^i - \tau_c.d_j^i - \tau_c L_{j-1}^i).(1+K_e)^{-(j)}\right)}{\sum_{j=1}^{N}(1-\tau_c).q_j^i.\pi_j^R.(1+K_e)^{-(j)}} + \frac{\sum_{j=1}^{N} x_j^i.(1+K_e)^{-(j)} + D_0^i}{\sum_{j=1}^{N}(1-\tau_c).q_j^i.\pi_j^R.(1+K_e)^{-(j)}} \qquad (18)$$

Appendix II: GPE Model

The GPE Model is a template interconnected gas system model that can be modified to represent local market conditions. The GPE Model assumes gas can be shipped from any supplier to any consumer subject to pipeline constraints, along with any gas shipper nomination constraints specified. The model is grounded firmly in welfare economics, with an objective function formally implemented by maximising the sum of consumer and producer surplus after satisfying differentiable equilibrium conditions:

Nodes, Demand and Supply

In the GPE Model, let $\mathbb{N}$ be the ordered set of nodes in our interconnected gas market with $|\mathbb{N}|$ being the total number of nodes in the set. Let η_i be node i where

$$i \in (1..|\mathbb{N}|) \wedge \eta_i \in \mathbb{N}, \qquad (19)$$

Let Q_i be the aggregate maximum demand for all consumer segments at node η_i expressed in TJ/d. Let Ψ_i be the set of gas suppliers at node η_iLet $\bar{\mathrm{P}}\psi_i$ be the maximum productive capacity of supplier ψ_i at node η_i, expressed in TJ/d. Let $\rho\psi_i$ be the quantity of gas supplied at node η_i by supplier ψ_i where

$$\psi_i \in (1..|\Psi_i|), \qquad (20)$$

Let c_i be the quantity of gas delivered to node η_i, expressed in TJ/d.

Pipelines

In the GPE Model, let Y be the ordered set of pipeline segments in the system and $|Y|$as the number of pipeline segments in the set. Table A2 sets out the ordered set of pipelines.

Table A2: Pipelines and Pipeline Capacity

Gas Pipeline (t_j)	Pipeline Name	Length (km)	From Node (η_i)	To Node (η_i)	Max Flow (TJ/d) (fc_i)	Tariff ($/GJ) ($p_k$)
CBR	Canberra to Dalton	58	Dalton	Canberra	52	$1.23
CGP	Carpentaria Gas Pipeline	840	Ballera	Mt Isa	119	$1.34
EGP	Eastern Gas Pipeline	797	Longford	Sydney	362	$2.90
LMP	Longford to Melbourne Pipeline	174	Longford	Melbourne	1030	$1.99
MAP	Moomba to Adelaide Pipeline	1185	Moomba	Adelaide	249	$0.83
MSP	Moomba to Sydney Pipeline	1300	Moomba	Sydney	446	$1.23
NVI	NSW - Victoria Interconnect	88	Culcairn	Young	223	$1.60
NVI_1	NSW - Victoria Interconnect	62.5	Melbourne	Culcairn	223	$1.60
QGP	Queensland Gas Pipeline	627	Wallumbilla	Gladstone	145	$1.08
RBP	Roma to Brisbane Pipeline	438	Wallumbilla	Brisbane	167	$0.63
SEAGas	South East Australia Gas Pipeline	689	Pt Campbell	Adelaide	314	$0.95
SWP	South West Pipeline	202	Pt Campbell	Melbourne	517	$2.31
QSN	QSN Link Pipeline	182	Ballera	Moomba	404	$1.34
SWQP	South West Queensland Pipeline	755	Wallumbilla	Ballera	404	$1.34
TGP_1	Tasmanian Gas Pipeline	740	Longford	Bell Bay	129	$2.55
TGP_2	Tasmanian Gas Pipeline	248	Bell Bay	Hobart	129	$2.55
APLNG	APLNG Pipeline	362	Surat	Gladstone	1700	$1.15
QCLNG	QCLNG Pipeline	543	Surat	Gladstone	1588	$1.15
GLNG	GLNG Pipeline	420	Surat	Gladstone	1400	$1.15
NGP	Northern Gas Pipeline	622	Tennant Creek	Mt Isa	106	$1.59

Sources: Simshauser & Gilmore (2025).

Let y_i connect to node j where

$$j \in (1..|Y|) \wedge y_i \in (1..|Y|), \quad (21)$$

Let $\mho_j$ and Υ_j be the two nodes that are directly connected to pipeline segment y_i where

$$\mho_j \in \mathbb{N}, \wedge \Upsilon_j \in \mathbb{N} \, | \mho_j \neq \Upsilon_j, \quad (22)$$

Let f_i be gas flow on pipeline segment y_i from $\mho_j$ to Υ_j expressed in TJ/d.

Let R be the ordered set of all paths. Let R_k be path k between two nodes η_x and η_y. Let r_{kj} be node j in path R_k where

$$j \in (1..|R_k|) \wedge r_{kj} \in R_k, \quad (23)$$

Let Y_r be the ordered set of pipeline segments in path R_k. Let y_{kj} be pipeline segment j in path R_k where

$$j \in (1..|R_k|) - 1, \quad (24)$$

Let fc_i be the maximum allowed flow along pipeline segment y_i. Let fm_i be the minimum allowed flow along pipeline y_i. Let fr_i be the flow of gas along path R_k. And let p_k be the cost of shipping 1 unit of gas (i.e. 1 TJ of gas) along path k, *subject to:*

$$\forall \mathrm{k}, \mathrm{w}, \mathrm{x}, \ \mathrm{r}_{kw} \neq r_{kx} | w \neq x, \quad (25)$$

and

$$\exists y_i \big| \mho_j = \mathrm{r}_{ki} \wedge \ \Upsilon_j = r_{k(i+1)} \vee \left(\Upsilon_{jg} = r_{ki} \wedge \mho_j = r_{k(1+i)}\right), \quad (26)$$

The purpose of equation (7) is to ensure that each node appears only once in a path, while the purpose of equation (8) is to ensure that all nodes are connected to the pipeline network. The flow on any given pipeline is the sum of flows attributed to all paths (that is, forward flows *less* reverse flows) as follows:

$$f_i = \sum_{k=1}^{R} fr_k | \, y_i \in R_K, \exists w{:}\, \Upsilon_i = r_{kw}^{\mho_i} = r_{k(w+1)} - \sum_{k=1}^{R} fr_k | \, y_i \in R_K, \exists w{:}\, \mho_i = r_{kw}^{\Upsilon_i} = r_{k(w+1)}, \quad (27)$$

The clearing vector of quantities demanded or supplied (including from storage facilities) in node $i = 1..n$, is given by the sum of flows in all paths starting at that node, less flows in paths ending at that node if applicable:

$$q_i = \sum_{k=1}^{R} fr_k | \, \eta_i = r_{k1} - \sum_{k=1}^{R} fr_k | \, \eta_i = r_{k|R_k|}, \quad (28)$$

Net positive quantities at a node are considered net supply $\rho\psi_i$ and negative quantities imply net demand c_i:

$$if\ q_i \begin{cases} \geq 0, \rho_{\psi i} = q_i \\ \leq 0, c_i = -q_i \end{cases}, \tag{29}$$

Demand Functions

Let $C_i(q)$ be the valuation that consumer segments at node η_i are willing to pay for quantity (q) TJ of gas. We explicitly assume demand in each period i is independent of other demand periods. Let $P_{\psi i}(q)$ be the prices that supplier ψ_i expects to receive for supplying (q) TJ of gas at node η_i.

Objective Function:

Optimal welfare will be reached by maximising the sum of producer and consumer surplus, given by the integrals of demand curves less gas production and pipeline costs. The objective function is therefore formally expressed as:

$$\mathrm{Obj} = \sum_{i=1}^{|N|} \int_{q=0}^{c_i} C_i(q)dq - \sum_{i=1}^{|N|} \sum_{\psi=1}^{\Psi_{(i)}} \int_{q=0}^{\rho\psi_i} \rho\psi_i(q)dq - \sum_{k=1}^{R} f_k . p_k \tag{30}$$

Subject to:

$$\mathrm{fm}_i \leq f_i \leq fc_i$$

$$0 \leq c_i \leq Q_i$$

$$0 \leq \ \rho\psi_i \leq \bar{\mathrm{P}}\psi_i.$$

Appendix III: NEMESYS Model

Let *H* be the ordered set of all half-hourly trading intervals.

$$i \in \{1 \ldots |H|\} \wedge h^i \in H, \quad (31)$$

Let *N* be the ordered set of nodes within the regional power system and let |*N*| be the total number of nodes in the set. Let η_n be node n where:

$$n \in (1..|N|) \wedge \eta_n \in N, \quad (32)$$

Aggregate final (grid-supplied) demand at each node comprises residential, commercial, and industrial consumer segments. Let *E* be the set of all electricity consumer loads in the model.

$$w \in \{1 \ldots |E|\} \wedge e_w \in E, \quad (33)$$

Let $V_w(q)$ be the valuation that consumer segment w is willing to pay for quantity q MWh of electricity. Let $q^i_{w,n}$ be the metered quantity consumed by customer segment w in each trading interval i at node n expressed in Megawatt hours (MWh). In all scenarios and iterations, aggregate demand is modelled as a strictly decreasing and linear function with own-price elasticity of -0.08[3] applied by reference to average wholesale prices p during solar periods, evening peak, and overnight periods against the equivalent 'base case' reference prices.

Generation investment and spot market trading are assumed to be profit maximising in a perfectly competitive market with all firms as price takers, thus yielding welfare maximising outcomes within the technical constraints outlined below. Let Ψ_n be the ordered set of generators at node n.

$$g \in \{1..|\Psi_n|\} \wedge \psi_{ng} \in \Psi_n, \quad (34)$$

Conventional plant are subject to a regime of both scheduled and forced outages. Planned outages are simulated at the rate of 35 days every 4th year, while forced outages are the subject of random simulations equivalent to ~3-6% per annum. Let $F(n, g, i)$ be the availability of each plant ψ_{ng} in each period i. Annual generation fleet availability is therefore:

$$\sum_{g=0}^{|\Psi_n|} F(n, g, i) \ \forall \ \eta_n, \quad (35)$$

Conventional plant face binding capacity limits and minimum load constraints. Let $\hat{g}_{\psi_{ng}}$ be the maximum productive capacity of generator ψ_{ng} at node n and let $\breve{g}_{\psi_{ng}}$ be the minimum stable load of generator ψ_n. Plant marginal running costs are given by mc_{ng}. Let $g_{\psi^i_{ng}}$ be generation dispatched (and metered) at node n by generator ψ_n in each trading interval i expressed in MWh. Let d^i_n be the cleared quantity of electricity delivered in trading interval i at node n expressed in MWh.

In our model, the Pumped Hydro plant form part of the incumbent plant stock and are a potential entrant. The pumped hydro fleet operates with imperfect foresight, using 'demand triggers' (MW) as a proxy for *water opportunity cost* as is frequently employed by long-duration storage assets. Pumped hydro plan operate as a single unit in each node. Define ρ^i_n as the *residual demand* in node n, being

[3] This elasticity estimate is consistent with Burke and Abayasekara (2018); AEMO, 2019 and Sergici *et al*., 2020).

demand plus net interconnector flows (imports) into node n (defined below) minus available variable renewable generation, defined as follows:

$$\rho_n^i = \sum_w q_{w,n}^i - \sum_{\bar{g}} \mathrm{F}(n, \bar{g}, i) - \sum_{\Omega_A} f_{An}^i, \quad (36)$$

where the sum over generating units is over zero marginal running cost renewable generators $\bar{g}$. Pumped hydro production is modelled to increase linearly from zero to nameplate capacity over a set range. Let $\xi_{+,0}$,n and $\xi_{+,full,n}$ (subject to additional constraints set out below) be the production range. This structure avoids sharp discontinuities in dispatch for small changes in demand. Similarly, let $\xi_{-,0}$ and $\xi_{-,full}$ be the demand range for charging (pumping) behaviour. These levels are set empirically to match typical operational behaviours, specifically at the 40th to 50th percentiles (charging) and 65th to 70th percentile of residual demand (generating).

Let SOC_n^i be the available stored energy for pumped hydro in region n, constrained by the nameplate storage capacity via $0 \leq SOC_n^i \leq SOC_n^{max}$, and satisfying the following energy balance timeseries:

$$SOC_n^{i+1} = SOC_n^i - g_{\psi_{n,phes}^i} \tau \times \{\gamma_n \; if \; g_{\psi_{n,phes}^i} < 0\} \quad (37)$$

where $\psi_{n,phes} \in \Psi_n$, τ is the simulation timestep, and γ_n is the average round-trip efficiency of the PHES fleet in that node. Initial conditions are $SOC_n^0 = SOC_n^{max}$. Finally, PHES charging load is constrained to be no more than the available renewable energy and coal capacity in each dispatch interval (i.e., the PHES will not charge off gas units). The PHES pumping load in each period is therefore given by:

$$g_{\psi_{n,phes}^i\,(pumping)} = (-1) \times minimum\ of \begin{cases} \hat{g}\psi_{n.phes} \times \min\left(1, \max\left(0, \frac{\rho_n^i - \xi_{-,full,n}}{\xi_{-,0,n} - \xi_{-,full,n}}\right)\right) \\ (SOC_n^{max} - SOC_n^i)/\tau/\gamma_h \\ \left(\sum_{g \in \psi_{n,coal}^i} \hat{g}\psi_{ng}\right) - \rho_n \end{cases} \quad (38)$$

For generation, output is similarly constrained to available SOC_n^i and the residual demand net minimum stable operating levels of coal units.

$$g_{\psi_{n,phes}^i(generating)} = minimum\ of \begin{cases} \hat{g}\psi_{n.phes} \times \min\left(1, \max\left(0, \frac{d_n^i - \xi_{+,0,n}}{\xi_{+,full,n} - \xi_{+,0,n}}\right)\right) \\ (SOC_n^i)/\tau \\ \rho_n - \left(\sum_{g \in \psi_{n,coal}^i} \check{g}\psi_{ng}\right) \end{cases} \quad (39)$$

Batteries arbitrage the highest and lowest demand periods on a day based on perfect foresight within the day. Batteries dispatch in the highest dispatchable demand periods and charge in the lowest periods. We assume batteries constrain their activity to one cycle per day, with commercial constraints described below. Given nodal battery $\hat{g}\psi_{n.bess}$ with nameplate energy storage capacity $S_{\psi_{n.bess}}$, for each simulation day D^d, let $\{\delta_n^{d,j}\}$ be the ordered (descending) set of *dispatchable demand* available to batteries defined as residual demand in node n net of either coal minimum load (if batteries can economically displace coal) or coal nameplate capacity (if batteries should preferentially displace gas),

$$\{\delta^{d,j}\} = \text{SortDescending}\left[\rho_{\mathrm{n}}^{\mathrm{i}} - \sum\nolimits_{g\in\psi_{n,coal}^{i}} \left[\breve{g}_{\psi_{ng}} \text{ or } \hat{g}_{\psi_{ng}}\right] - g_{\psi_{n,phes}^{i}}\right],$$

$$\rho_{n}^{i} \in \{1 \dots |D^{d}|\} \wedge D^{d} \subset H. \quad (40)$$

Dropping the superscript d and subscript n for clarity, battery dispatch q^j in each sorted interval is optimised to minimise the number of periods of non-zero dispatch $|\{1\ if\ q^j > 0\ else\ 0\}|$ subject to constraints that dispatch in each period is less than nameplate capacity $q^j \leq \hat{g}_{\psi_{n.bess}}$, is less than available demand $q^j \leq \delta^j$, and either $\sum_{j\ s.t.\ q^j>0} q^j = S_{\psi_{n.bess}}$ or $|\{1\ if\ q^j > 0\ else\ 0\}| = |\mathrm{D}|$ (i.e., the battery has either dispatched its total storage capacity across the day or there was insufficient dispatchable demand to do so).

By default, battery dispatch is constrained to never oppose PHES operation. Symmetric calculations are applied to battery charging, charging in the lowest *dispatchable demand* periods but constrained not to charge off gas, i.e., dispatchable demand is below coal headroom s.t. $\delta^j \leq \sum_{g\in\psi_{n,coal}^{i}}\left(\hat{g}_{\psi_{ng}} - \breve{g}_{\psi_{ng}}\right)$. Battery dispatch in each day is then remapped to the original indices to obtain the final net dispatch, $g_{\psi_{n,bess}^{i}}$ (positive for generation, negative for charging).

Let $p_{\psi^i}(q)$ be the uniform clearing price that all dispatched generators receive for generation dispatched or pay during charging, $g_{\psi_n^i}$. Were it not for network constraints, generation and transmission investment options, the problem to be solved is in fact a simple one:

$$\min_{q_n^i}\left(\sum\nolimits_i mc_{\psi_{ng}}^{i}\left(g_{\psi_{ng}^{i}}\right) q_n^i\right), \quad (41)$$

where

$$\exists\psi_{ng}^{i} | if\ \left(g_{\psi_{ng}^{i}}\right)\begin{cases} \neq 0, 0 < \breve{g}_{\psi_{ng}} < g_{\psi_{ng}^{i}} < \hat{g}_{\psi_{ng}} \forall\, \psi_n \\ = 0, 0 \end{cases} \wedge \left[\left(\sum q_{w,n}^{i} - \sum g_{\psi_{ng}^{i}}\right) / \sum q_{w,n}^{i}\right] \ngtr USE, \quad (42)$$

and

$$If\ \left(\sum q_{w,n}^{i} - \sum g_{\psi_{ng}^{i}} > 0 \middle| USE > 0, p_{\psi^i}(q) = \$17{,}500/\mathrm{MWh},\right), \quad (43)$$

Unserved Energy (USE) defines the reliability constraint. In the model, the NEM's reliability standard is used with USE not to exceed 0.002%. Eq.(12) constrains unit commitment of each generator $g_{\psi_{ng}^{i}}$ to within their credible operating envelope, and for the market as a whole to operate within the reliability constraint, USE. Eq.(13) specifies that any period involving load shedding, market clearing prices default to the Value of Lost Load of $17,500/MWh, noting this has a tight nexus with the reliability standard.[4]

[4] From a power system planning perspective, the overall objective function is to minimise $VoLL\ x\ USE + \sum_{i=1}^{n} c(G)\ |\ VoLL\ x\ USE + c(\bar{G}) = 0$, where $VoLL$ is the Value of Lost Load, USE is Unserved Energy, and where $c(G)$ is the cost generation plant, and $c(\bar{G})$ is the cost of peaking plant capacity. Provided these conditions hold, it can be said there is a direct relationship between Reliability and the VoLL. An alternate expression where reliability criteria is based on Loss of Load Expectation is $LoLE = CONE/VoLL$, where CONE is the cost of new entry. For an excellent discussion on the relationship between VoLL and reliability criteria, see Zachary, Wilson and Dent (2019).

Let Ŧ be the ordered set of transmission lines t_j linking nodes, and let |Ŧ| be the number of transmission lines in the zone.

$$t_j \in (1..|Ŧ|) \wedge t_j \in Ŧ, \quad (44)$$

Let Ω_A and Ω_B be two nodes directly connected to transmission line t_j where

$$\Omega_A \in \mathrm{N}, \wedge \Omega_B \in \mathrm{N} \,|\Omega_A \neq \Omega_B, \quad (45)$$

Let f_{AB} be the flow between the two nodes. Let $\hat{f}_j$ be the maximum allowed flow along transmission line t_j and let $\check{f}_j$ be the maximum reverse flow. The clearing vector of quantities demanded q_n^i or supplied at node n in each trading interval i is given by the sum of flows across all transmission lines starting at that node, less flows across transmission lines ending at that node, if applicable. Net positive quantities at a node are considered to be net supply $g_{\psi_n^i}$ $(i.e. \sum g_{\psi_{ng}^i})$ and negative quantities imply net demand V_n^i:

$$if\ q_n^i \begin{cases} \geq 0, g_{\psi_n^i} = q_n^i \\ \leq 0, V_n^i = -q_n^i, \end{cases} \quad (46)$$

Integration of plant costs in the model centres around the transposition of three key variables, Marginal Running Costs $mc_{\psi n}$ Fixed O&M Costs $FOM_{\psi n}$ & where applicable (annualised) new entrant generator Capital Costs, $K_{\psi n}$ and (annualised) new Transmission line Capital Costs, K_{tj}. These parameters are the key variables in the half-hourly power system model and are used extensively to meet the objective function.

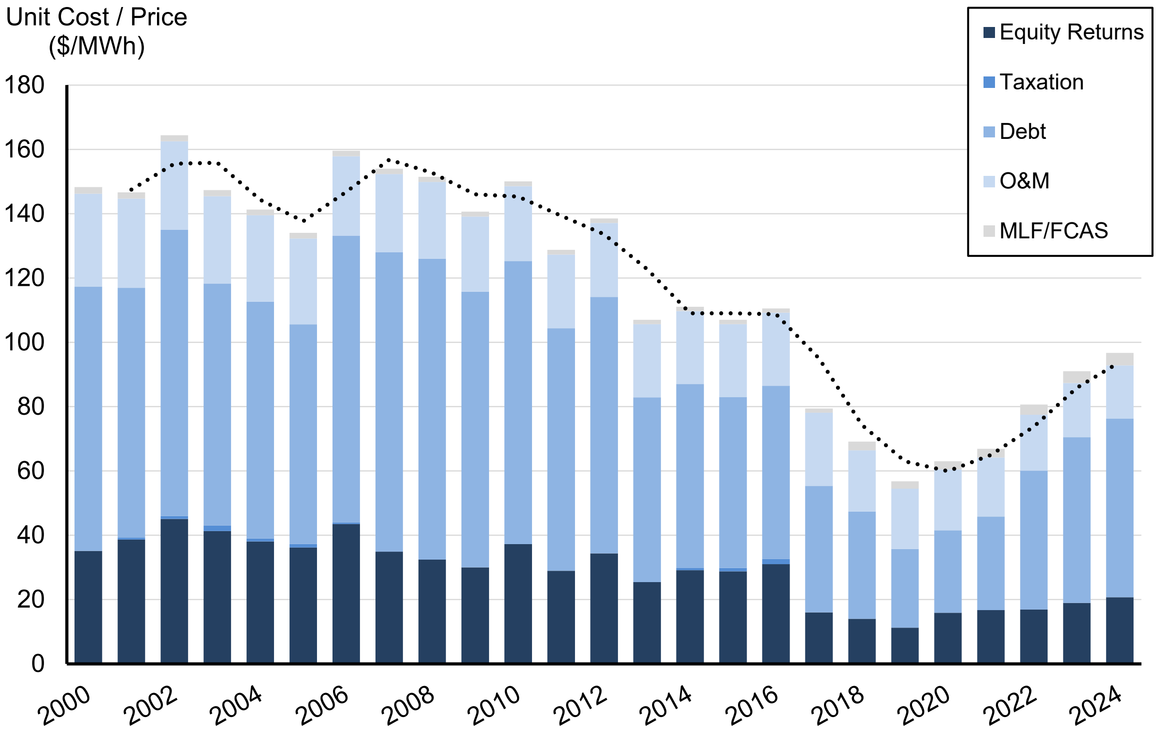
Optimal welfare will be reached by maximising the sum of producer and consumer surplus, given by the integrals of demand curves less marginal electricity production costs and any (annualised) generation $K_{\psi n}$ or transmission K_{tj} augmentation costs. The objective function is therefore expressed as:

$$\text{Obj} = \left[\sum_{i=1}^{|H|}\sum_{w=1}^{|E|}\sum_{n=1}^{|\mathrm{N}|}\int_{q=0}^{v_n} V_n(q_{n,w}^i)\partial q\right] - \left[\sum_{i=1}^{|H|}\sum_{n=1}^{|\mathrm{N}|}\sum_{\psi=1}^{|\Psi|}\int_{q=0}^{g_{\psi n}} mc_{\psi n}(q_{\psi,n}^n)\partial q + FOM_{\psi n} + \sum_{n=1}^{|\mathrm{N}|} K_{\psi n} + \sum_{j=1}^{|Ŧ|} K_{tj}\right], \quad (47)$$

S.T

$$0 \leq q_i \leq V_i \wedge \check{f}_j \leq f_i \leq \hat{f}_j \wedge 0 \leq \check{g}_{\psi i} \leq g_{\psi i} \leq \hat{g}_{\psi i}.$$

Appendix IV: Wind costs (2000 – 2025, constant 2025 dollars)



Source: Simshauser & Gilmore (2022)

Appendix V: NEMESYS Results

AVERAGE OF 100 Iterations	2005	Escalated 2005 --> 2025	Counterfactual Coal	Counterfactual Gas	Base Case 50% RE
Unit Cost	**$47.1/MWh**	**$88.7/MWh**	**$151.5/MWh**	**$150.3/MWh**	**$99.7/MWh**
Spot Price	$40.4/MWh	$76.1/MWh	$114.7/MWh	$112.4/MWh	$86.1/MWh
Unserved Energy	407 MWh		225 MWh	96 MWh	15 MWh
Unserved Energy	0.001%		0.001%	0.000%	0.000%
# VoLL Events	5.4		4.5	3.8	3.2
Renewable %	**0.0%**		**0.0%**	**0.0%**	**50.9%**
CO_2 Emissions	43.2 mt		46.5 mt	44.1 mt	23.9 mt
Sys. Max Demand	8,226 MW		11,822 MW	11,855 MW	11,219 MW
Sys. Energy Demand	49,402 GWh		56,359 GWh	58,269 GWh	55,495 GWh
Rooftop Solar	-		-	-	8,270 GWh
Pumping/Charging	627 GWh		650 GWh	667 GWh	3,881 GWh
Agg. Final Demand	50,029 GWh		57,009 GWh	58,936 GWh	67,646 GWh
Installed Capacity					
Coal	6,000 MW		6,000 MW	5,200 MW	3,600 MW
CCGT	350 MW		2,100 MW	3,500 MW	1,050 MW
OCGT	2,750 MW		4,000 MW	3,750 MW	4,750 MW
Wind	-		-	-	4,200 MW
Solar	-		-	-	5,700 MW
Rooftop PV	-		-	-	6,000 MW
Pumped Hydro	500 MW		500 MW	500 MW	1,200 MW
Batteries	-		-	-	850 MW
TOTAL Capacity MW	**9,600 MW**		**12,600 MW**	**12,950 MW**	**21,350 MW**
Coal ACF	87.7%		89.7%	89.5%	76.6%
CCGT ACF	41.6%		44.9%	54.3%	32.0%
OCGT ACF	8.9%		3.1%	1.7%	3.7%
Wind ACF	-		-	-	34.3%
Solar ACF	-		-	-	23.3%
Pumped Hydro ACF	11.2%		12.0%	11.0%	23.8%
Battery ACF	-		-	-	7.8%
Coal Fleet Availability	**92.0%**		**90.6%**	**90.6%**	**90.5%**
VRE Curtailment					**7.4%**
TXab Congestion Hrs	0 Hrs		0 Hrs	0 Hrs	27 Hrs
Fixed Costs					
Fixed Costs Coal	$1,445,400,000		$4,704,120,000	$4,074,808,608	$1,024,920,000
Fixed Costs CCGT	$109,149,600		$562,917,600	$938,196,000	$281,458,800
Fixed Costs OCGT	$195,129,000		$502,605,000	$469,098,000	$603,126,000
Wind	-		-	-	$1,227,234,331
Solar	-		-	-	$479,602,107
Pumped Hydro	$43,800,000		$65,700,000	$65,700,000	$293,810,400
Battery	-		-	-	$143,707,800
Variable Costs					
Coal	$461,099,105		$1,735,787,364	$1,518,127,075	$1,086,944,956
CCGT	$31,024,241		$803,797,872	$1,618,667,216	$286,014,539
OCGT	$103,836,387		$193,075,284	$100,748,085	$274,403,559
Pumped Hydro Sell	$46.6/MWh		$162.7/MWh	$138.4/MWh	$134.8/MWh
Pumped Hydro Buy	$22.4/MWh		$63.4/MWh	$99.4/MWh	$43.9/MWh