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APPENDICES

Policy sequencing: on the electrification of gas loads in Australia's National Electricity Market

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Appendix I: J-Solve

Model Logic

J-Solve is a least-cost expansion planning and constrained dispatch model for an interconnected electricity system. Optimal welfare will be reached by minimising the sum of plant stock capital costs, production costs, and any costs of unserved energy. The optimisation determines the generating capacity (and if applicable storage capacity) of each unit, and its corresponding generation (and charging) in each period, as well as the amount of unserved energy or curtailed negative demand in each period.

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, and ultimately seeks to maximise welfare in the market for natural gas. This objective is formally implemented by maximising the sum of consumer and producer surplus after satisfying differentiable equilibrium conditions. Model logic is as follows.

Nodes, Demand and Supply

Let T be the ordered (time sequential) set of dispatch periods, with $|T|$ being the total number of periods, and periods labelled by index t such that

$$t \in (1..|T|) \qquad (1)$$

Each period has a duration Δt.

Let R be the ordered set of regions in our interconnected electricity market with $|R|$ being the total number of regions in the set, and each region denoted by index i such that

$$i \in (1..|R|) \qquad (2)$$

Let $D_{i,t}$ be the aggregate demand for all consumer segments at node i in time period t, expressed in MW, which may be negative due to non-market or embedded generation. Let V_i be the set of generators at node i. Let P_{ij} be the maximum productive capacity of supplier j in region i, expressed in MW, and let $\mathrm{p}_{ij,t}$ be the production (in MW) of generator j in region i in time period t, where j

$$\mathrm{j} \in (1..|\mathrm{V}_i|) \qquad (3)$$

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Generation is limited by nameplate capacity and availability percentage $A\%_{ij,t}$ in any period. Availability may be reduced either by underlying renewable trace determined by JWeather, or by planned or forced outages, or both.

$$0 \leq \mathrm{p_{ij,t}} \leq \mathrm{A\%_{ij,t}} \times \mathrm{P_{ij}} \leq \mathrm{P_{ij}} \ \forall\, i, j, t \tag{4}$$

Generation is limited by nameplate capacity and availability percentage $A\%_{ij,t}$ in any period. Availability may be reduced either by underlying renewable trace determined by JWeather, or by planned or forced outages, or both.

$$0 \leq \mathrm{p_{ij,t}} \leq \mathrm{A\%_{ij,t}} \times \mathrm{P_{ij}} \leq \mathrm{P_{ij}} \ \forall\, i, j, t \tag{5}$$

Storage assets

Let S_i be the subset of generator indices of in region i with energy storage.

Let the storage capacity for the relevant generator be Q_{ij} and the available storage level at the start of period t be $q_{ij,t}$. Let $c_{ij,t}$ be the charging rate in MW of the asset, where maximum charge and generation rates are assumed to be symmetric, such that:

$$0 \leq \mathrm{c_{ij,t}} \leq \mathrm{P_{ij}} \ \forall\, t \ \wedge \ i \in (1..|R|) \wedge j \in S_i \tag{6}$$

Charging is assumed to have efficiency η_{ij}, which is assumed to capture the roundtrip efficiency. Storage levels are tracked and constrain generation through the balancing equations:

$$p_{ij,t} \times \Delta t \leq \mathrm{q_{ij,t}} \quad \forall\, i, j, t \tag{7}$$

$$c_{ij,t} \times \Delta t \times \eta_{ij} \leq Q_{ij} - \mathrm{q_{ij,t}} \quad \forall\, i, j, t \tag{8}$$

$$q_{ij,t+1} = \mathrm{q_{ij,t}} - p_{ij,t} \times \Delta t + c_{ij,t} \times \Delta t \times \eta_{ij}, \ \ \forall\, i, j, t \tag{9}$$

To prevent edge effects a circular charge level constraint is applied such that

$$q_{ij,0} = q_{ij,t_{max}} - p_{ij,t_{max}} \times \Delta t + c_{ij,t_{max}} \times \Delta t \times \eta_{ij} \quad \forall\, i, j \tag{10}$$

Let Y be the set of all reference years modelled (with total years $|Y|$) and let T_y for $y \in Y$ be the set of ordered time indices for that year, and $T_{y,m}$be the set of indices. All indices are included such that the ordered concatenation yields the total ordered set of indices (i.e., time sequential ordering is preserved:

$$T_{1,1} \frown T_{1,2} \frown \ldots \frown T_{1,12} \frown T_{2,1} \ldots T_{|T|,11} \frown T_{|T|,12} = T \tag{11}$$

Total storage throughput has an annual cycle limit ζ_j, typically as required by battery warranty or maintenance schedules, such that:

$$\textstyle\sum_{t \in T_y} g_{ij,t} \Delta t \leq \mathrm{Q_{ij}} \times \zeta_\mathrm{j} \quad \forall\, y \in \mathrm{Y} \ \wedge \ i \in (1..|R|) \wedge j \in S_i \tag{12}$$

For existing hydro generators, minimum and maximum monthly and annual limits apply based on historical inflows and outflows for the corresponding reference year. These take the form of annual $\xi_{j,y}$ and monthly $\xi_{j,y,m}$ energy limits such that:

$\sum_{t \in T_y} g_{ij,t} \Delta t \ \leq \zeta_{\mathrm{j,y}} \quad \forall\, i, j, y$ iff g_{ij} is a hydro unit (13)

$\sum_{t \in T_{y,m}} g_{ij,t} \Delta t \ \leq \mathrm{Q_{ij}} \times \zeta_{\mathrm{j,y,m}} \quad \forall\, 1 \leq m \leq 12, i, j, y$, iff g_{ij} is a hydro unit (14)

Interconnectors

Let IC be the ordered set of transmission interconnectors in the system and $|IC|$as the number of transmission lines in the set. Let interconnector t_k $(0 < k < |IC|)$ connect nodes $r_{t_k,-}$ and $r_{t_k,+}$. Let flows from the negative to positive region are $f_{k,t}$, between forward and reverse interconnector flow limits $F_{k,+}$ and $F_{k,-}$,

$$F_{k,-} \ \leq f_{k,t} \leq F_{k,+} \ \ \forall\, k, t \tag{15}$$

Regional supply demand constraint

Supply must match demand in all regions in all periods, such that the sum of all generation in the region plus interconnector inflows minus interconnector outflows plus load shedding ($USE_{i,t}$>0, in megawatts) must equal the regional demand plus curtailment of negative demand $\gamma_{i,t} > 0$ (e.g., curtailment of behind the meter rooftop PV, in megawatts).

$$\sum_{j \in V_i} g_{ij,t} + \sum_{k \mid r_{t_{k,+}} = r_i} f_{k,t} - \sum_{k \mid r_{t_{k,-}} = r_i} f_{k,t} + USE_{i,t} = \mathrm{D_{i,t}} + \gamma_{i,t}$$

$$\forall\, t \ \wedge \ i \in (1..|R|) \tag{16}$$

Objective function

Capital costs are converted to annualised \$/MW/year figures through $C_{P,ij}$ for unit j in region i, and let $C_{Q,ij}$ be the analogous total annualised capex (\$/MWh/year) for storage capacity and let $R_{ij,t}$ be the marginal running cost, including fuel, O&M, etc. VCR_i is the value of customer reliability (\$/MWh) in region i, i.e., the cost attributable to $USE_{i,t}$. It is assumed to be constant in all periods, but could be made time dependent (e.g., higher or lower values in summer or winter).

$$\mathrm{Obj} = \sum_{i=1}^{|R|} \sum_{j=1}^{|V|} \Big(\big[C_{P,ij} \times P_{ij} \times |Y| + C_{Q,ij} \times Q_{ij} \times |Y| \big] + \sum_{t=1}^{|T|} R_{ij,t} \times g_{ij,t} \times \Delta t \Big) + \sum_{i=1}^{|R|} \sum_{t=1}^{|T|} VCR_i \times USE_{i,t} \times \Delta t \tag{17}$$

In addition to cost minimisation, reliability standards can dictate a maximum percentage of unserved energy σ, viz.

$$\sum_{t=1}^{|T|} USE_{i,t} \leq \sigma \times \sum_{t=1}^{|T|} D_{i,t} \ \ \forall\, i \in (1..|R|), \tag{18}$$

Appendix II: GPEM Model

1.2 GPE Model Logic

The GPEM Model is a template interconnected gas system model that can be modified to represent local market conditions. The 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

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

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

$$\psi_i \in (1..|\Psi_i|), \tag{2}$$

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. Let y_i connect to node j where

$$j \in (1..|Y|) \wedge y_i \in (1..|Y|), \tag{3}$$

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

$$\mho_j \in \mathbb{N}, \wedge\, \Upsilon_j \in \mathbb{N}\ |\mho_j \neq \Upsilon_j, \tag{4}$$

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

$$j \in\ (1..|R_k|) \wedge r_{kj} \in R_k, \tag{5}$$

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

$$j \in\ (1..|R_k|) - 1, \tag{6}$$

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:*

$$\forall \mathrm{k}, \mathrm{w}, \mathrm{x},\ \ \mathrm{r}_{kw} \neq r_{kx}|w \neq x, \tag{7}$$

and

$$\exists y_i \,|\, \text{Ʊ}_j = \mathrm{r}_{ki} \wedge \text{Ɣ}_j = r_{k(i+1)} \vee \left(\text{Ɣ}_{jg} = r_{ki} \wedge \text{Ʊ}_j = r_{k(1+i)}\right), \qquad (8)$$

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:

$$f_i = \textstyle\sum_{k=1}^{R} fr_k \,|\, y_i \in R_K, \exists w\!: \text{Ɣ}_i = r_{kw}^{\text{Ʊ}_i} = r_{k(w+1)} - \textstyle\sum_{k=1}^{R} fr_k \,|\, y_i \in R_K, \exists w\!: \text{Ʊ}_i = r_{kw}^{\text{Ɣ}_i} = r_{k(w+1)}, \qquad (9)$$

The set of Pipelines is as follows:

Gas Pipeline (t_j)	Pipeline Name	Length (km)	From Node (η_i)	To Node (η_i)	Max Flow (TJ/d) (fc_i)	Tariff ($/GJ) (ᵽ_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 & Nelson (2015a), updates from AEMO.

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:

$$q_i = \textstyle\sum_{k=1}^{R} fr_k \,|\, \eta_i = r_{k1} - \textstyle\sum_{k=1}^{R} fr_k \,|\, \eta_i = r_{k|R_k|}, \qquad (10)$$

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

$$if\ q_i \begin{cases} \geq 0, \rho_{\psi i} = q_i \\ \leq 0, c_i = -q_i, \end{cases} \qquad (11)$$

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:

$$\mathrm{Obj} = \sum_{i=1}^{|N|}\int_{q=0}^{c_i} C_i(q)dq - \sum_{i=1}^{|N|}\sum_{\psi=1}^{\Psi(i)}\int_{q=0}^{\rho\psi_i}\rho\psi_i(q)dq - \sum_{k=1}^{R} f_k.p_k \qquad (12)$$

Subject to:

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

$$0 \le c_i \le Q_i$$

$$0 \le \rho\psi_i \le \bar{P}\psi_i.$$

Appendix V - PF Model

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

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

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.

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

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:

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

If thermal plant 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

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

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:

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

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.

$$x_j^i = c_j^i.\pi_j^C, \quad (7)$$

Plant capital costs X_0^i give rise to tax depreciation (d_j^i) 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:

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

From here, taxation payable $\left(\tau_j^i\right)$ at the corporate taxation rate (τ_c) 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.

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

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

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:

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

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 $\left(I_j^i\right)$ is calculated as the product of the (fixed) interest rate on the loan or Bond by the amount of loan outstanding:

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

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 $\left(X_0^i\right)$. 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).

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

Credit metrics[2] $\left(\delta_j^{VI}\right)$ and $\left(\omega_j^{VI}\right)$ 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

[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.

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:

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

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:

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

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

Let $IRR \equiv K_e$

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

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

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

Table A1 – Technology Costs

Generation Technology		Wind	Solar	Battery	Pumped Hydro	OCGT
Project Capacity	(MW)	1,000	400	200	2,000	250
- Storage Capacity	(Hrs)	-	-	4	24	-
Overnight Capital Cost	($/kW)	3,300	1,600	525	2,525	1,613
- Storage	($/kWh)	-	-	225	70	-
- Contingency		-	-	-	30%	-
Plant Capital Cost	($ M)	3,300	640	409	12,007	397
Operating Life	(Yrs)	35	30	20	100	35
Annual Capacity Factor	(%)	35.0%	26.5%	14.7%	18.0%	5%
Transmission Loss Factor	(MLF)	0.990	0.970	1.000	1.000	1.000
Transmission REZ Costs	($/MW/a)	25,000	12,500			
Fixed O&M	($/MW/a)	50,000	20,000	10,000	20,000	1,000
Variable O&M	($/MWh)	0.0	0.0	0.0	1.0	8.0
FCAS	(% Rev)	-1.0%	-1.0%	4.0%	10.0%	2.5%

Table A2 – Capital Markets Inputs

Project Finance			
Debt Sizing Constraints			
- DSCR	(times)	1.8	
- Gearing Limit	(%)	0.4	
- Default	(times)	1.05	
Project Finance Facilities - Tenor			
- Term Loan B (Bullet)	(Yrs)	5	
- Term Loan A (Amortising)	(Yrs)	10	
- Notional amortisation	(Yrs)	15	
Project Finance Facilities - Pricing			
- Term Loan B Swap	(%)	4.09%	
- Term Loan B Spread	(bps)	180	
- Term Loan A Swap	(%)	4.19%	
- Term Loan A Spread	(bps)	209	
- Refinancing Rate	(%)	6.1%	
Expected Equity Returns	(%)	8.0%	
Balance Sheet Finacing			
Credit Metrics (BBB Corporate)		Merch	Reg.
- FFO / I	(times)	4.2	2.4
- Gearing Limit	(%)	40.0	65.0
- FFO / Debt	(%)	20%	9%
Bond Issues			
- 5 Year	(%)	5.45%	
- 7 Year	(%)	5.59%	
- 10 Year	(%)	5.65%	
Commonwealth Bonds			
- 10 Year	(%)	4.14%	
Expected Equity Returns	(%)	10.0%	