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Demand shocks from the gas turbine fleet in Australia's National Electricity Market

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Abstract
The long run task of Australian power system planners is to identify the structural adjustment pathway associated with retiring the National Electricity Market's (NEM) coal fleet. System planning models seek to do this at minimum cost subject to a reliability constraint. This involves the deployment of low-cost intermittent wind and solar resources with a mix of dispatchable, flexible 'firming' assets. Coal's energy-producing role is thus replaced by renewables, and firming duties by short duration batteries, intermediate duration pumped hydro and the last line of defence – gas turbines. As it turns out, the mix of firming assets is crucial. In this article, we examine 12 (anonymised) electricity market model forecasts in the post-coal era and find all have a surprisingly heavy reliance on gas turbines during critical event winter days. Using a dynamic partial equilibrium model of the east Australian gas market, we test the severity of what appear to be demand shocks from an emergent gas turbine fleet. The episodic demand shocks present as intractable, particularly if batteries and pumped hydro plant are 'underweight' within the aggregate generating portfolio. Adequate time is available for policymakers to respond in an orderly manner.

Keywords *gas markets, gas turbines, renewables, firming capacity.*

JEL Classification *D52, D53, G12, L94 and Q40.*

EPRG WORKING PAPER

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1. Introduction

The National Electricity Market or 'NEM' commenced 25 years ago at a time when coal plant dominated the aggregate supply function. In the early 2000s, the ~30GW coal fleet had 91% energy market share. Hydro and gas-fired generation played a relatively modest role with ~4% market share each. Until recently, the NEM was the OECD's most coal-intensive power system. This context underscores the challenge of Australia's decarbonisation task. At the time of writing in 2024, coal's market share had fallen to 56% and the renewable market share had risen to 39%.

The relative growth in NEM aggregate demand throughout the 2000s was primarily in peak periods, at which point the role of natural gas and gas turbines became more prominent (Nelson and Simshauser, 2013). Falling capital costs, short start-up and shut-down times, and pliable fuel procurement meant the gas turbine became the optimal technology for peaking duties throughout the world's deregulated electricity markets (Rehman et al., 2015; Guittet et al., 2016). In Australia's NEM, 35 gas turbine projects (c.$14.2 billion) were committed over the period 1998-2021, representing 9600MW of generating capacity in a market with a maximum demand of 35,000MW (Simshauser and Gilmore, 2022). However, gas turbines are largely constrained to peaking duties with NEM energy market shares in the 4-8% range.

The task of decarbonisation means the power system's supply-side will experience material changes in technology, and in operating duties. Given largely inelastic aggregate demand in the medium run, the role of baseload plant may eventually become redundant following an influx of intermittent wind and solar PV. Coal plant minimum stable loads are incompatible with high levels of stochastic Variable Renewable Energy (VRE) output (Simshauser and Wild, 2024). The historic functions of 'intermediate plant duties' and 'peaking plant duties' may similarly be altered to collectively form 'firming duties' with this dispatchable fleet comprising short duration batteries, intermediate duration pumped hydro and gas turbines – the latter being the *'capacity of last resort'* during renewable droughts (see for example Gilmore et al., 2022, 2023).

The purpose of this article is to examine the role of gas turbines and their role as the capacity of last resort. In particular, our focus is on the parallel functioning, and capacity, of the network of natural gas pipelines to cope with 'demand shocks' (i.e. peak daily flows) from the NEM's gas turbine fleet in a post-coal, high VRE environment.

Examination of the gas market has been systemically overlooked in academic research and applied NEM power system modelling exercises – including by the market operator. In all power system planning models with very high levels of VRE, the *capacity of last resort* takes on a critical role vis-à-vis power system reliability. With few exceptions, all NEM models, and all NEM modellers, currently rely on gas turbines to balance power system demand in a manner that meets the over-arching energy policy objective function, viz. to minimise cost subject to reliability (and CO_2 emissions) constraints.

In this article, we examine outputs from 12 power system models and 10 modellers (anonymised) for two future years 3035-3036. This period was deliberately selected because the majority of the coal-fired fleet is assumed to have been retired and replaced by VRE. All models and all modellers signal sharp episodic increases in gas turbine plant duties – surging for 5-10 days at a time during winter months when renewable output is lowest. Crucially, all modellers assume an *endlessly flexible* gas market. The assumption of 'endlessly flexible gas markets' has proven to be entirely reasonable over the past two decades.

This article tests the normative electricity market model assumptions by identifying the outer operating boundary of the adjacent market for natural gas, given known market conditions. We do so by relying on a nodal model of the Australian east coast gas market capable of identifying daily flow limits – the same model which predicted the 2018 gas market shortfalls on Australia's east coast in the pages of this journal almost 10 years go.[1]

To summarise our results, gas turbine output during periods of renewable droughts in winter months in a post-coal era appears to be incompatible with the outer operating envelope of Australia's eastern gas market as we currently understand it. The fleet of gas turbines will be much larger in the 2030s, and their activity more intensive in short bursts, creating a particularly acute peak load problem. While sufficient 'gas commodity' exists, the east coast network of gas pipelines and gas storages are inadequate. Their augmentation, and alternate supply options, will therefore be critical. The upside to our analysis is that sufficient time exists to do so.

This article is structured as follows. In Section 2, we present a brief review of literature. Section 3 introduces some gas market fundamentals. Section 4 provides an overview of our gas market model and inputs. Section 5 examines model results. Policy implications and concluding remarks follow.

2. Review of literature

Our literature review covers two distinct topics relevant to our subsequent analysis: i). the evolution of power system planning, and ii). the east Australian gas market.

2.1 The evolution of power system planning

The objective function of power system planning has historically focused on minimising costs subject to a reliability constraint. The optimal mix of generation plant could be identified through static partial equilibrium models dating back to Boiteux (1949), Turvey (1964) and Berrie (1967). The maths behind these static models made it possible to identify the optimal mix of base (e.g. coal, nuclear), intermediate (e.g. combined cycle gas turbines, coal) and peaking (e.g. open cycle gas turbines burning gas or liquid fuels, hydro and pumped hydro) plants against an inelastic aggregate demand function represented by a fixed load duration curve. Reserve plant margins required to meet the reliability constraint were similarly solved mathematically, with the relevant formulation first expressed in Calabrese (1947).

Later, Booth (1972) and others would devise dynamic partial equilibrium frameworks through Linear Programming models comprising security-constrained unit commitment methods which efficiently accounted for stochastic plant availability and back-solved requisite reserve plant margins to manage the *Loss of Load Probability*. In theory at least, the accuracy of plant investment programs for a given load curve were enhanced dramatically. Such models inevitably underscore the critical role of gas turbines undertaking peaking and reserve plant duties, particularly from the 1990s when their entry costs plunged relative to other forms of peaking applications (Rehman et al., 2015; Guittet et al., 2016).

[1] See Simshauser and Nelson (2015a). See also 2018 AFR article by Matthew Stevens on Gas Shortages.

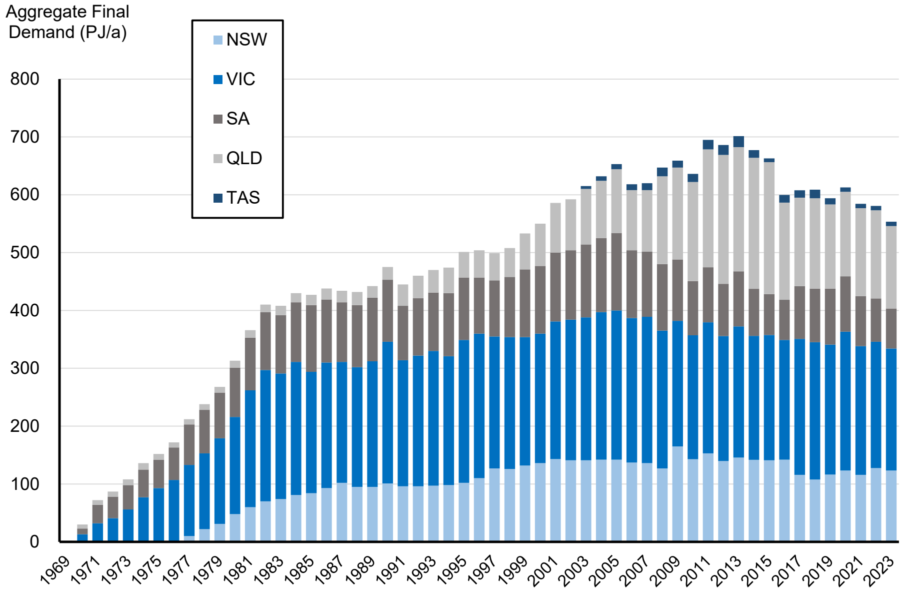
Dynamic, security-constrained, unit commitment models and the associated partial equilibrium framework have long been an indispensable planning tool for power system planners. This has been amplified in the 21st century, with the objective of power system planning having been re-stated to minimising costs, subject to reliability *and* CO_2 emissions constraints. Static models can be adapted to capture the implications of early-stage intermittency (see Martin and Diesendorf, 1983), but once VRE market share exceeds ~20%, the complexity of the 'firming task' means such models break down (Simshauser and Newbery, 2024). Dynamic models thus become essential to capture the fundamental change in plant operating duties, including the fading role of the "baseload" plant.

Coal plant start-up times are measured in hours, not minutes. Therefore, they remain on-line 24 hours per day. As renewables increase their market share, periods of excess supply occur, resulting in negative price events. A large, inflexible coal fleet in the presence of rapidly rising intermittent renewables can be expected to confront a rising number of negative price events (Nelson et al., 2022). This is especially prevalent in solar-rich regions such as Queensland, where negative price events have risen from 9 hours in 2018 to over 800 hours in 2024. Furthermore, the synchronicity of rooftop and utility-scale solar during daylight hours results in falling minimum grid-supplied loads, meaning that not only do negative prices increase in frequency, but the load to be supplied is likely to fall below the minimum stable generation of coal plant, forcing their closure both economically, and physically (Simshauser and Wild, 2024). It is for this reason that a portfolio of dispatchable, flexible 'firming plant' comprising i). short duration utility-scale batteries, ii). intermediate duration pumped hydro and iii). gas turbines as the *capacity (and energy) of last resort* will become essential.

2.2 The east Australian market for natural gas

While the supply of natural gas on Australia's east coast can be traced at least as far back as 1899 in Roma (Queensland) its development at-scale occurred from the late-1960s (Vaiyavuth et al., 2008). Expansion followed quickly as Figure 1 illustrates. Growth was driven by the fact that natural gas was a cleaner, more efficient and reliable fuel than the town gas it replaced (Taylor and Hunter, 2018).

Figure 1: Eastern Australia aggregate final gas demand (1969-2023)



Source: Simshauser & Nelson (2015b), EnergyEdge GMAT[2].

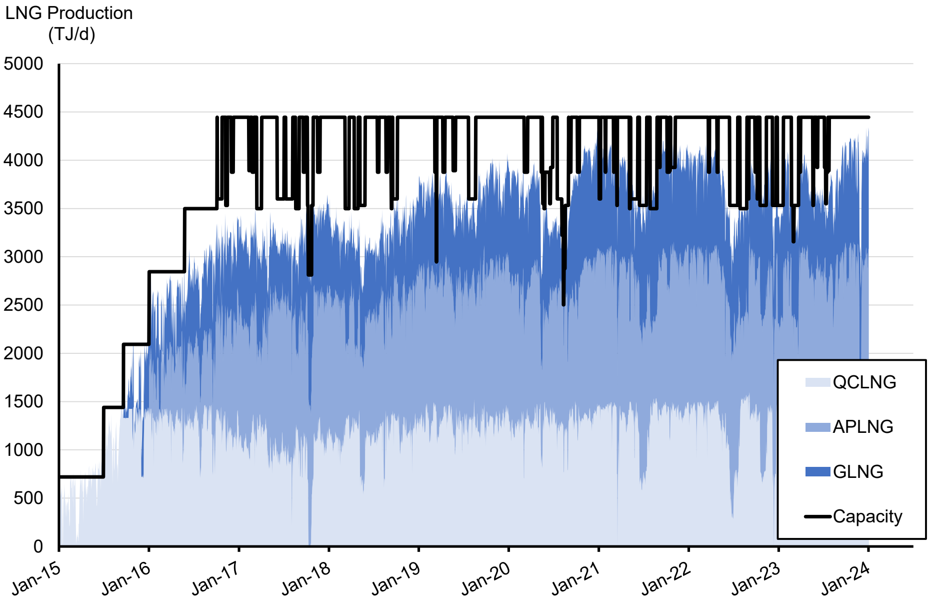
[2] GMAT, or 'Gas Market Analysis Tool', is a commercial product made available by EnergyEdge (https://www.energyedge.com.au/products/gas-market-analysis-tool-gmat/).

During the 1990s and early-2000s, substantial coal seam gas resources were discovered in the Surat Basin of southern Queensland (Towler *et al.*, 2016). By 2012, the so-called 'Proven and Probable' gas reserves totalled 40,000+ petajoules, dwarfing the ~7000 petajoules of existing conventional reserves (see Simshauser and Nelson, 2015a). These discoveries formed the foundation of a Liquified Natural Gas (LNG) export industry in Gladstone, Queensland (Billimoria et al., 2018).

The most prominent aspect of the run-up in gas reserves and the associated development of LNG export industry capacity (2007-2016) was the rapid change in market sentiment. Sentiment quickly turned from a positive economic development story to a negative one, characterised by sharply rising domestic gas prices (Wood and Carter, 2013; Grafton et al., 2018; Ledesma and Drahos, 2018) and risks of domestic supply shortfalls (Simshauser and Nelson, 2015a, 2015b; Billimoria et al., 2018).

Imbalances within the east Australian market for natural gas would ultimately have material impacts for electricity market prices as McConnell and Sandiford (2020) and Nolan et al. (2022) explain. To summarise the most important elements of the literature from 2015 onwards, the consistent theme involves the 'tightly balanced' supply-demand situation for natural gas given an inherent overbuild of LNG plant capacity in Gladstone. This structural imbalance is best captured through Figure 2. Here, the ramp-up of the three LNG export terminals (comprising six LNG 'trains') over the period 2015-2016 is identified by the solid black line series, with available capacity fluctuating thereafter in line with maintenance outages. The stacked area chart illustrates LNG production by facility. Note that LNG production rarely meets aggregate LNG plant capacity, which implies plant over-capacity. In consequence, domestic prices became inextricably linked to LNG export market prices in Australia for the first time.

Figure 2: Installed LNG plant capacity vs LNG production



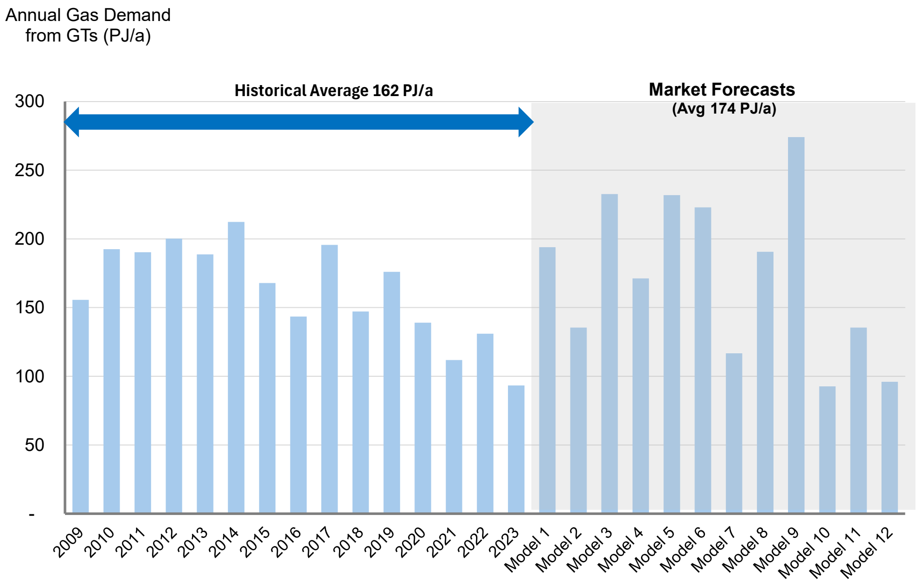
Source: Simshauser & Gilmore (2022), EnergyEdge GMAT.

3. Gas Market Fundamentals

Before commencing our quantitative analysis in Sections 4-5, it is worth highlighting what triggered our initial line of inquiry, and what we expected to find through gas market modelling. Recall from Section 1 we collated 12 power system model outputs from 10 electricity market participants and forecasters. Our period of interest was the future years 2035-2036, when the majority of coal generation plant is expected to have exited, and an emergent fleet of batteries, pumped hydro and additional gas turbine plant capacity is assumed to have been commissioned. Our focus was the forecast operational duties of gas turbine plant as the capacity (and energy) of last resort.

To provide context, Figure 3 collates historic gas used in electricity generation (2009-2023) and compares this with the 12 anonymised forecasts of gas used by gas turbines in the 2030s. Prima facie, there appears to be nothing unusual about the forecast model results. The average gas use over the period 2009-2023 was 162PJ/a, with a range of 93-212PJ/a. The anonymised forecasts of gas used by gas turbines in the post-coal 2035-2036 era averages 174PJ/a with a range of 76-270PJ/a. In a market comprising aggregate final gas demand of 1,900 PJ/a, these variations appear minor.

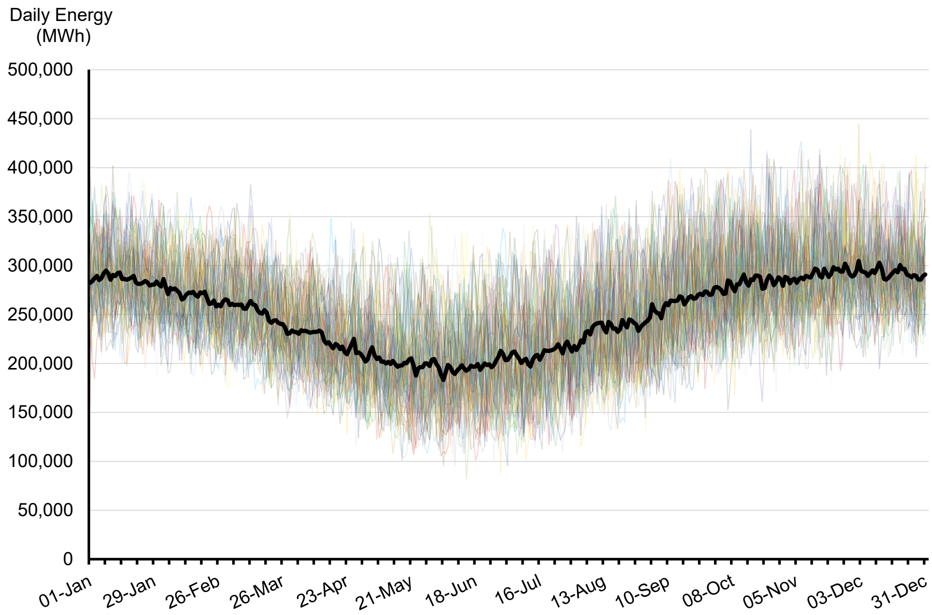
Figure 3: Historic vs Demand Forecasts for Gas used by Gas Turbines (PJ/a)



Source: EnerSource: EnergyEdge GMAT (historic results)

However, aggregate annual gas use overlooks intra-period use. Our interest is gas used during winter months, and our reasoning is best explained through Figure 4. This data, from Gilmore et al. (2022), collates 80 years of historic weather data applied to an optimal combination of wind and solar PV sites throughout Australia's NEM following the exit of coal, simulating daily VRE production.

Figure 4: NEM renewable production post-coal, based on 80 years of historic weather data



Source: Gilmore et al., (2022)

Notice in Figure 4 that during winter months there is a distinct depression in renewable output. Solar irradiation is naturally lower with shorter days, and as it turns out, most NEM wind resources exhibit distinctly lower capacity factors during winter as well. Consequently, we should anticipate higher levels of firming capacity activity during winter.

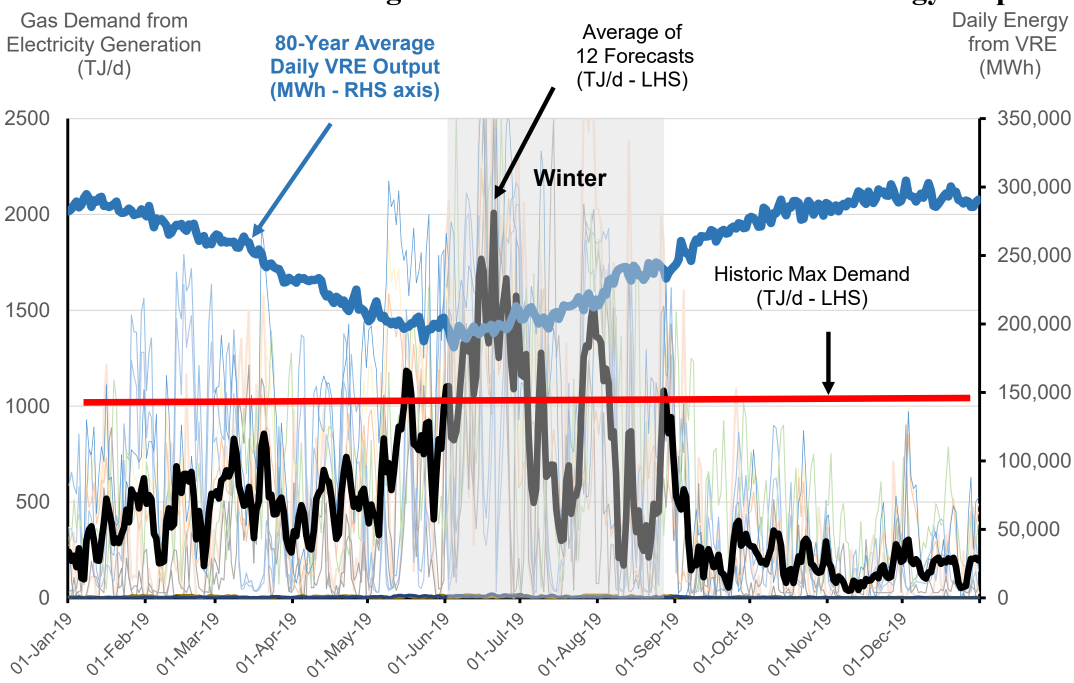
When we analysed the daily gas demand (TJ/d) for the future years 2035-2036 from the 12 forecast models, we found materially elevated gas use in all models as expected (see Fig.5 and also Table A1 in Appendix 1). Figure 5 illustrates these results and has three distinct data lines:

- First, the red horizontal line represents the historic maximum gas demand by gas-fired generation plant, at ~1170 terajoules per day (TJ/d) - LHS y-axis.

- Second, the thick blue line series illustrates average output from the optimised NEM renewables fleet based on 80-year historic weather data (transposed from Figure 4, RHS y-axis).

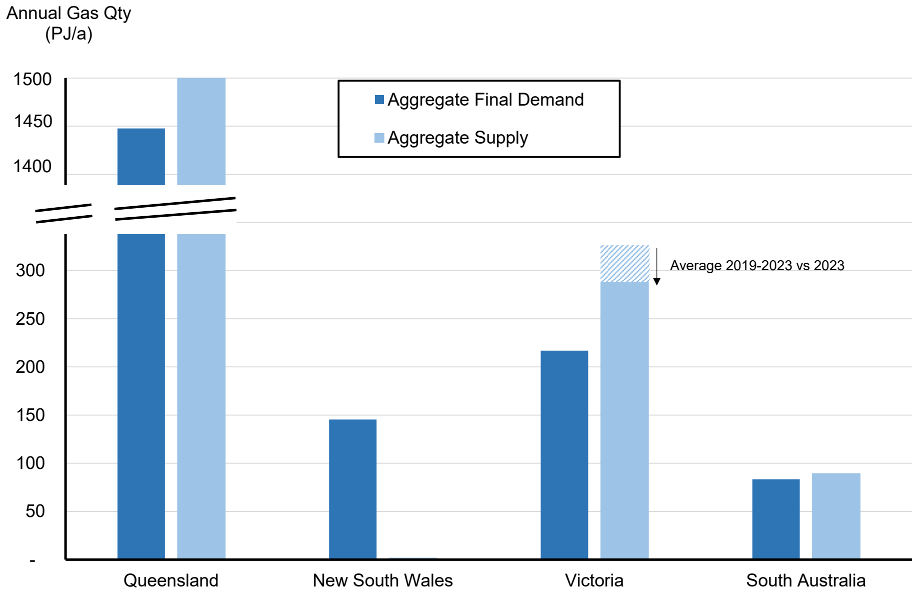
- Finally, the solid thick black line is the average of the gas used by gas turbines from the 12 forecast models (LHS axis). Each scenario is represented by a feint line. Note some scenarios exceed the LHS y-axis (see also Table A1 in Appendix 1).

Figure 5: Gas demand from gas turbines in 2035 vs renewable energy output



Results from Figure 5 suggest market stress events may occur during winter months when renewable output is lower, and, when domestic gas demand reaches its seasonal peak flows (i.e. due to coincident residential and commercial heating loads). It is worth identifying where the epicentre of any problem is likely to occur. By examining demand and supply by state over the period 2019-2023, historic imbalances are most pronounced in NSW (see Figure 6). And while not evident from the data, residential peak loads are highest in Victoria – a market in which local supply is anticipated to fall, according to the latest outlook from the Market Operator[3].

Figure 6: Aggregate final demand/supply imbalance by State (avg: 2019-2023)



Source: Energy Edge GMAT.

[3] See AEMO at https://aemo.com.au/en/energy-systems/gas/gas-forecasting-and-planning/gas-statement-of-opportunities-gsoo

To summarise, electricity market forecasts of the generation mix and the operating duties of plant in the post-coal environment routinely point to episodic surges in demand by the gas turbine fleet during winter months. Dynamic power system simulation models assume an endlessly flexible gas market. This context frames our modelling task – what are the existing operating boundaries of the east Australian gas market?

4. Gas Market Model – 'GPE Model'

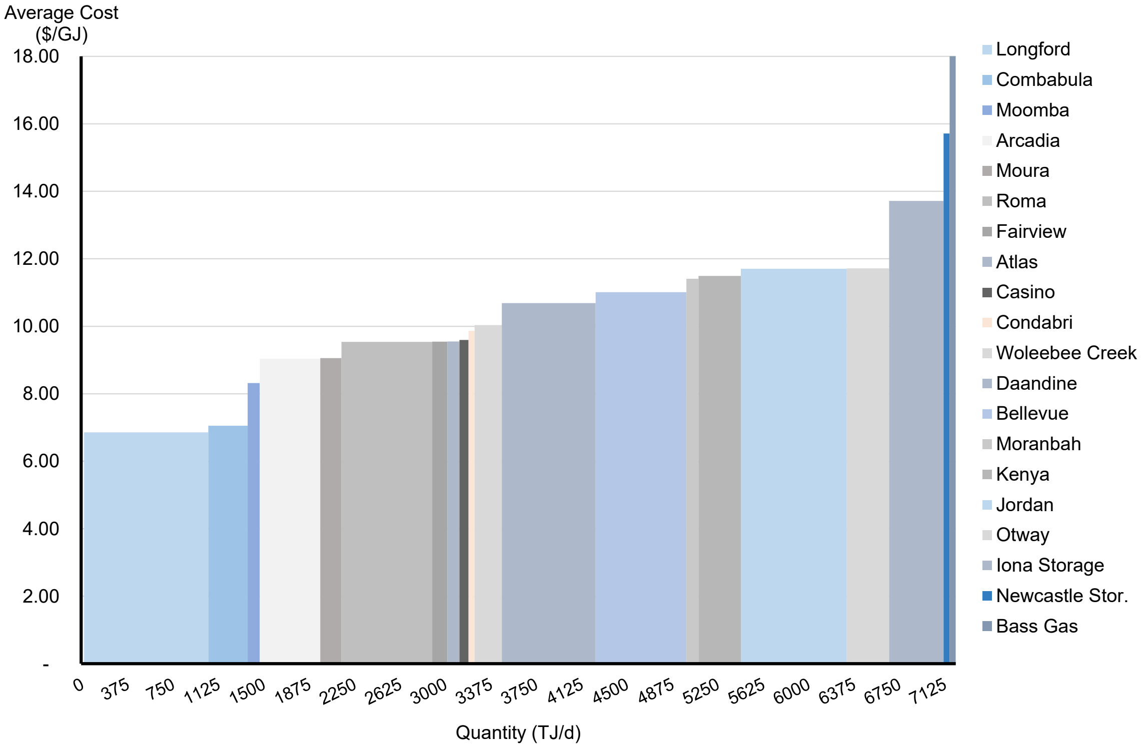
This Section outlines our data inputs and model logic. Our gas market model, known as the 'GPE Model', is a dynamic, partial equilibrium (LP) model representative of the east Australian gas market, including all major gas fields, major transmission pipelines and demand segments by location.

4.1 Aggregate supply function

Our model is populated with an aggregate supply function comprising all major operational Figure 7:gas fields on Australia's east coast. The detail of our supply-side is clearly set out in Figure 7. The most recent Gas Statement of Opportunities released by the Australian Energy Market Operator (see footnote #3) identifies rapidly falling supplies in Southern Australia, and the Bass Straight in particular. For our purposes, we hold the existing aggregate supply function constant. By implication, if they are not then our model results understate the problem to be solved. This is a very important caveat.

In Figure 7, each gas field or supplier is represented by their generalised average total cost. Estimated marginal costs for conventional gas fields are ~35% of average total cost, and unconventional coal seam gas is ~60%. The GPE Model accommodates multiple offer prices (paired with offer quantities). We use two offers per gas field, viz. marginal costs ($/GJ) in the first offer price band paired with the expected average annual output quantity (TJ/d). The second offer band is priced at average total cost and paired with maximum field output as the quantity. We assume the market is highly competitive. Consistent with Australian policy, no price on carbon has been included.

Figure 7: Aggregate gas supply function (east coast gas fields)



4.2 Gas Storage Assets

The GPE Model incorporates two critical storage assets which necessarily appear in both aggregate demand and supply functions (incl. Figure 7). The first of these is the Iona Storage facility (located at the Port Campbell node, see Figure 9), comprising 26 PJ – 8 PJ of which we treat as non-usable 'pad gas'. The plant has an injection rate into the network of 445 TJ/d, with a re-injection rate of 140 TJ/d. The second storage is the Newcastle facility connected to the Sydney node, comprising 1.5 PJ of storage (all usable) with an injection rate of 60 TJ/d and re-injection rate of 10 TJ/d. There are other storage assets throughout the eastern gas network, but as our subsequent model results reveal, these two storage assets are critically located, and hence are of central interest to our analysis.

Scheduling of storage assets requires bid/offer prices to be nominated. We co-optimise these via an ex-ante sub-routine within the model through a simple linear programming profit maximising function which incorporates a constraint to ensure storage assets are at full capacity prior to the start of each winter.

4.3 Aggregate final demand

Our model has been populated with aggregate final gas demand, daily resolution, for each gas node and each consumer segment using historic data from 2019 onwards. The GPE Model identifies three distinct consumer segments with the locational aggregate demand function:

1. gas use by domestic residential, commercial and industrial customers – collectively referred to as the 'DomGas' segment;

2. gas used in electricity generation; and

3. gas exports by the LNG fleet in Gladstone, Queensland.

Table 1 provides a statistical summary of aggregate final gas demand by the three consumer segments over the period 2019-2023 measured in PJ/a. We rely on 2019 and 2020 data as the base years in our forecast simulations.

Table 1: Aggregate final demand (PJ/a) by segment (2019-2023)

Final Demand (PJ/a)	2019	2020	2021	2022	2023
DomGas (Resi, C&I)	453	464	473	478	427
Electricity Generation	138	112	85	98	72
Final Domestic Demand	591	576	557	577	499
LNG	1,216	1,328	1,411	1,357	1,370
Aggregate Final Demand	1,807	1,904	1,968	1,934	1,869

Table 2 presents *daily maximum demand* over the same period, measured in TJ/d.

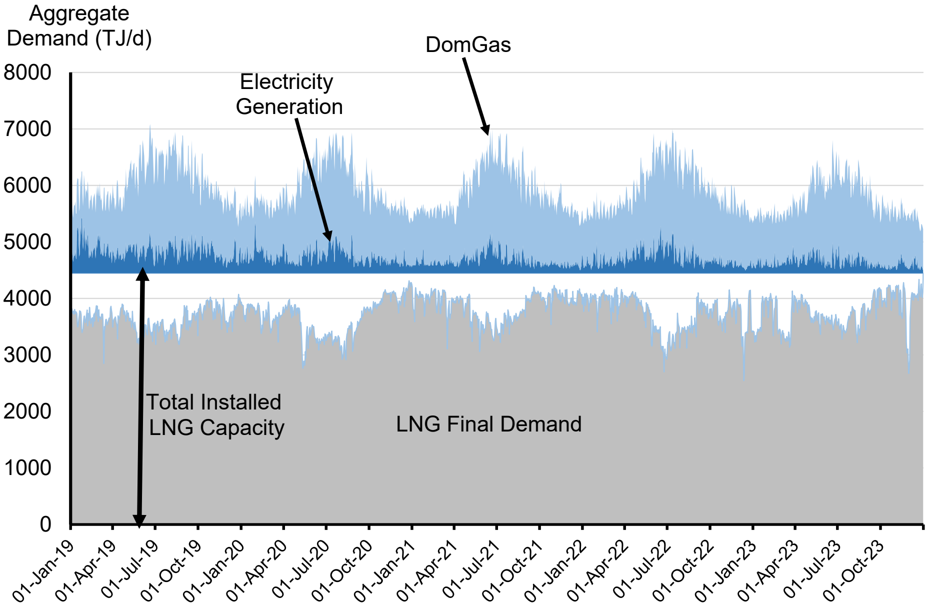
Table 2: Maximum final demand (TJ/d) by segment (2019-2023)

Max Demand (TJ/d)	2019	2020	2021	2022	2023
DomGas (Resi, C&I)	2,207	2,116	2,302	2,253	1,987
Electricity Generation	988	923	737	839	563
Max. Domestic Demand	2,789	2,647	2,854	2,826	2,550
LNG	4,023	4,157	4,314	4,196	4,341
Max. Final Demand	6,287	6,144	6,375	6,300	6,066

A detailed visual of the Tables 1-2 data is illustrated in Figure 8 (daily resolution). Note LNG fleet 'capacity' is distinguished from LNG 'final demand'. The grey shaded area denoted 'LNG Final Demand' depicts the gas historically consumed by the LNG terminals from 2019, whereas the white shaded area above this represents idle LNG capacity. This idle

LNG capacity technically represents demand for gas not satisfied due to price, gas availability, pipeline constraints, plant maintenance or some other reason. Next in Figure 8, the dark blue shaded area represents historic final gas demand from gas-fired electricity generators, while the light blue area represents historic DomGas final demand.

Figure 8: Aggregate final gas demand incl. LNG capacity from 2019



Source: Simshauser & Gilmore (2022), EnergyEdge GMAT.

Data from Figure 8, which was obtained from the energy market system 'GMAT[4]' has been loaded into the GPE Model. For our purposes, we define our aggregate final demand forecast for the mid-2030s 'post-coal environment' simulations in our GPE Model as follows:

1. DomGas Demand: base years 2019 and 2020 (per Figure 8) are entered and then reduced throughout the entire east Australian system by -8%. This reduction in DomGas demand reflects our assumed own-price elasticity estimate of -0.18 for natural gas, drawn from Li et al., (2022).

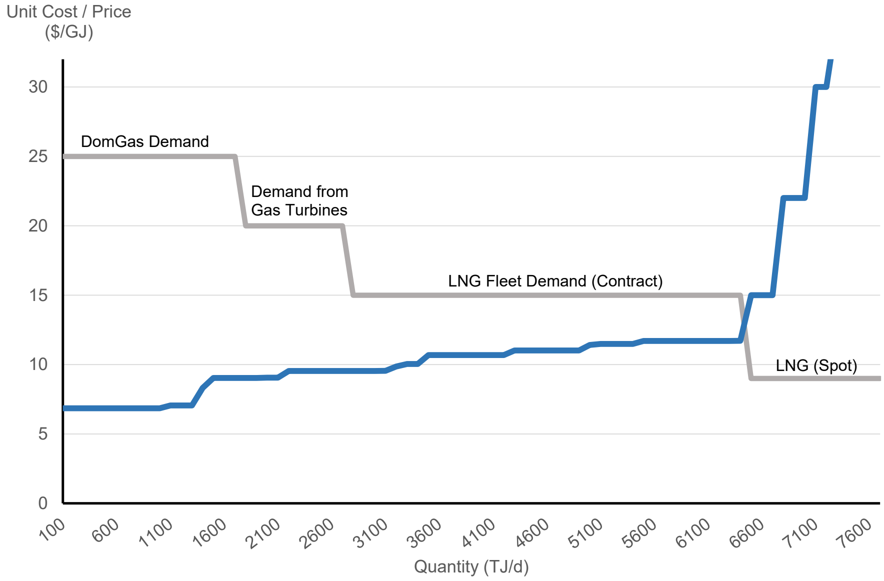
2. Historic gas used in electricity generation in 2019-2020 is removed from the dataset, and replaced by the array of forecast model results in Figure 5.

3. LNG demand is split between historic final demand (grey shaded area in Figure 8) and idle (but available) LNG capacity (white shaded area in Figure 8). The latter is bid into the market at the 'netback price' of natural gas, that is, the spot LNG cargo price (i.e. the Japan-Korea Marker[5]) less LNG production and transportation costs.

Structurally, a *stylised version* of the aggregate demand and supply curves in the GPE Model for a particular day during winter, in an unconstrained state, would look as follows:

[4] See also Footnote #2.
[5] See https://www.spglobal.com/commodityinsights/en/our-methodology/price-assessments/lng/jkm-japan-korea-marker-gas-price-assessments

Figure 9: Stylised aggregate demand and aggregate supply (daily resolution)



There are two critical points arising from inspection of Figure 9:

1. DomGas demand is to be satisfied first, followed by demand from Gas Turbines. This is a crucial assumption.

2. Consistent with the shape of the aggregate demand function in Figure 9, we assume LNG demand *is* endlessly flexible.

Noting the shape and structure of aggregate demand and aggregate supply in Figure 9, the only reason DomGas and/or Gas Turbine demand would not be satisfied on any given day would be due to constraints within the gas network, and exhausted local storages.

At this point, it is appropriate to introduce the shipping capacity constraints of the east coast gas network, as reflected in our GPE Model.

4.4 GPE Model structure

The east Australian gas market spans from Tennant Creek in the Northern Territory, through to Queensland incorporating major gas fields near Roma and LNG export terminals at Gladstone, then down to the southern markets of South Australia (Moomba fields), New South Wales, Victoria (Longford and Port Campbell production) and Tasmania. Figure 10 illustrates key demand centres, gas fields and gas transmission pipelines contained in our GPE Model.

Figure 10: GPE Model demand centres, gas fields and pipelines

Details of the gas transmission pipelines, pipeline lengths, connecting nodes, pipeline capacity (TJ/d) and pipeline tariffs (expressed in $/GJ) appear in Table 3. Given the number of pipeline routes and nodes, there are 286 plausible supply combinations and associated constraint equations along with 834 variables to solve in each trading interval (i.e. daily resolution).

Table 3: 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 ($/GJ) ($\rho_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.

4.5 GPE Model Logic

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 N be the ordered set of nodes in our interconnected gas market with $|\mathrm{N}|$ being the total number of nodes in the set. Let η_i be node i where

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

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

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

Let $\mho_j$ and $\mathrm{Ɣ}_j$ be the two nodes that are directly connected to pipeline segment y_i where

$$\mho_j \in \mathrm{N}, \wedge \, \Upsilon_j \in \mathrm{N} \, | \mho_j \neq \Upsilon_j, \quad (4)$$

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

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

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

$$j \in (1..|R_k|) - 1, \quad (6)$$

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:*

$$\forall \mathrm{k}, \mathrm{w}, \mathrm{x}, \; \mathrm{r}_{kw} \neq r_{kx} | w \neq x, \quad (7)$$

and

$$\exists y_i \big| \mho_j = \mathrm{r}_{ki} \wedge \, \Upsilon_j = r_{k(i+1)} \vee \left(\Upsilon_{jg} = r_{ki} \wedge \mho_j = r_{k(1+i)}\right), \quad (8)$$

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:

$$f_i = \textstyle\sum_{k=1}^{R} fr_k | \, y_i \in R_K, \exists w \colon \Upsilon_i = r_{kw}^{\mho_i} = r_{k(w+1)} - \sum_{k=1}^{R} fr_k | \, y_i \in R_K, \exists w \colon \mho_i = r_{kw}^{\Upsilon_i} = r_{k(w+1)}, \quad (9)$$

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:

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

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

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

Demand Functions

Let $\mathrm{C}_i(q)$ 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 $\mathrm{P}_{\psi i}(q)$ 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:

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

(12)

Subject to:

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

$$0 \leq c_i \leq Q_i$$

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

5. Model Results

In Figure 5, we identified demand surges from an emergent gas turbine fleet in future years 2035-2036. These spikes in demand appeared at various levels of intensity across all 12 electricity market forecasts. State gas imbalances identified in Figure 6 revealed NSW is likely to be a vulnerable region.

We therefore start our modelling sequence in Section 5.1 by examining the most significant demand shock scenario amongst our 12 forecast models. This scenario (which appears as 'Model 1' in Fig.3) can be briefly described as one in which renewable targets are met, coal plant closures occur as scheduled, but the NEM is underweight 'pumped hydro plant' and therefore has a much greater reliance on gas turbines to maintain security of supply in the electricity market model (a 16GW gas turbine fleet compared to the existing 10GW plant stock). The 'Model 1' scenario therefore represents a 'worst-case scenario', and we should therefore anticipate shortages due to severe gas network constraints and a lack of localised storage in southern markets (especially NSW and VIC).

Thereafter, we model 4 subsequent scenarios to examine the nature and timing of the gas market dynamics we identify. These subsequent scenarios appear in Sections 5.2-5.4.

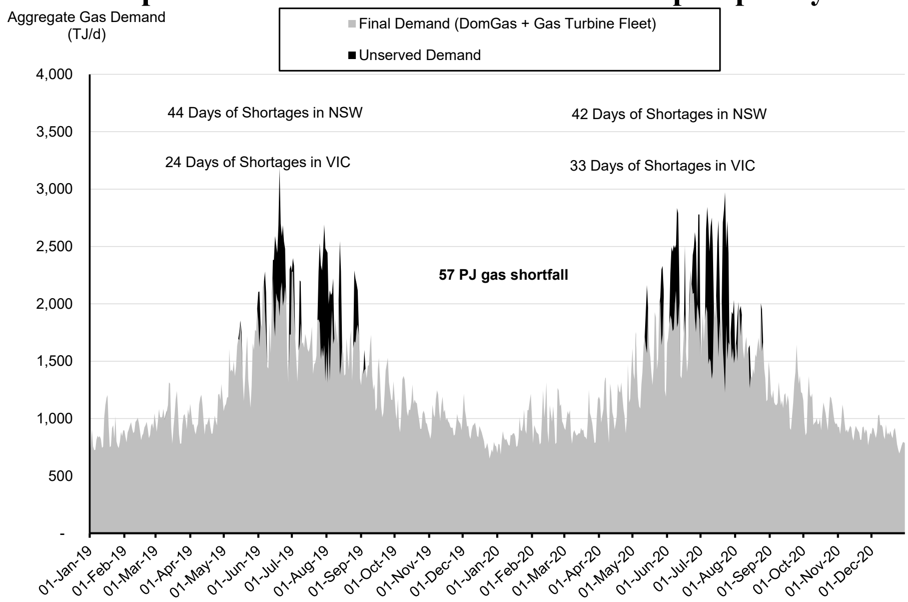
5.1 NEM with no new pumped hydro and heavy reliance on gas turbines

In the 'no new pumped hydro scenario', annual gas used by the gas turbine fleet equates to ~194 PJ/a. Prima facie, there is nothing unusual about 194 PJ of gas used by gas turbines in a single year. It sits neatly within the bounds of historic gas generation outcomes illustrated in Figure 3 (i.e. historic range = 93-212 PJ/a). However, this scenario exhibits as much as ~3000TJ/d of gas demand from gas turbines during critical event days on a NEM-wide basis (cf. 1170TJ/d historically).

Due to the diurnal and seasonal pattern of renewables, limited storage capacity of 4-hour batteries (which are uneconomic to provide reserve energy for infrequent events), and no new pumped hydros being developed, aggregate storages in both the electricity and gas market are frequently exhausted in the winter months. This 'Model 1' scenario is not contemplated by other modellers, or the Australian Energy Market Operator in their annual Integrated System Plan (AEMO includes ~8GW of new pumped hydro in its forecasts). GPE Model results for the east Australian gas market for this 'Model 1' scenario are illustrated in Figure 11.

In Figure 11, the first point to note is that 'Final Demand' is represented by the light shaded grey area and represents the combined 'demand served' for DomGas and the Gas Turbine Fleet. Conversely, 'Unserved Demand', depicted by the dark-shaded area, represents that component of gas turbine demand for natural gas which exceeds gas market capacity.

Figure 11: 2030s post-coal closure scenario with no new pumped hydro



In Figure 11, unserved gas demand is extensive. In aggregate across the two-year window, shortfalls equate to 57 PJ (26 PJ in year 1, 31 PJ in year 2). NSW is forecast to experience more than 40 critical events per annum, and somewhat unexpectedly, Victoria is forecast to experience more than 20 days of shortfalls per annum.

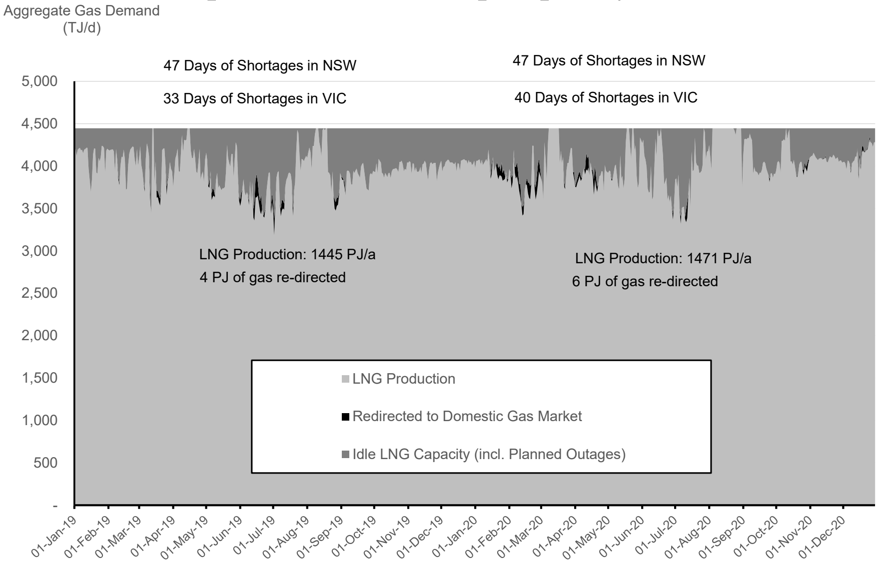
Recall our assumed merit order of demand (Figure 9) ranks DomGas and Gas Turbine segments ahead of LNG segment demand. The model assumes this due to the political economy of unserved domestic gas demand. Consequently, if it was merely a matter of inadequate availability of natural gas commodity, the model would curtail LNG facilities' consumption and re-direct the feedstock to the DomGas/electricity generation market.

Figure 12 illustrates the modelled impacts on LNG fleet operations. As it turns out, during the first simulated year the LNG fleet redirects just 4 PJ (out of its 1449 PJ demand schedule) to the domestic market in accordance with the merit order of demand. This occurs to varying degrees on 44 specific trading days. However, only 22 of the 44 days coincide with physical shortage events in southern markets. In other words, shortage events would be even more amplified were it not for the flexibility assumed by the LNG fleet.

During the second simulated year, the result is 6 PJ across 65 days, and curiously, only 5 of the 65 days coincided with critical event days in NSW. The most important implication of this is that the remaining 47 PJ of shortages across the two years are pipeline and/or local production and storage-deficit related events. The problem of unserved demand is thus structural – inadequate pipeline capacity between Queensland's gas fields and the southern markets of NSW and VIC, and inadequate local storage in Sydney and Melbourne.

Specifically, extensive pipeline constraints exist across the Moomba to Sydney Pipeline (~80 days per annum), Longford to Melbourne pipeline (~35 days per annum), South-West Pipeline (Port Campbell to Melbourne, ~28 days per annum), and the Southwest Queensland Pipeline and QSN Link (Wallumbilla to Ballera and through to Moomba, ~25 days per annum). Furthermore, the two critical gas storages are largely exhausted by early July each year, given total gas market loadings (see chart at Appendix I, Figure A-1).

Figure 12: LNG fleet operations - 'no new pumped hydro' scenario

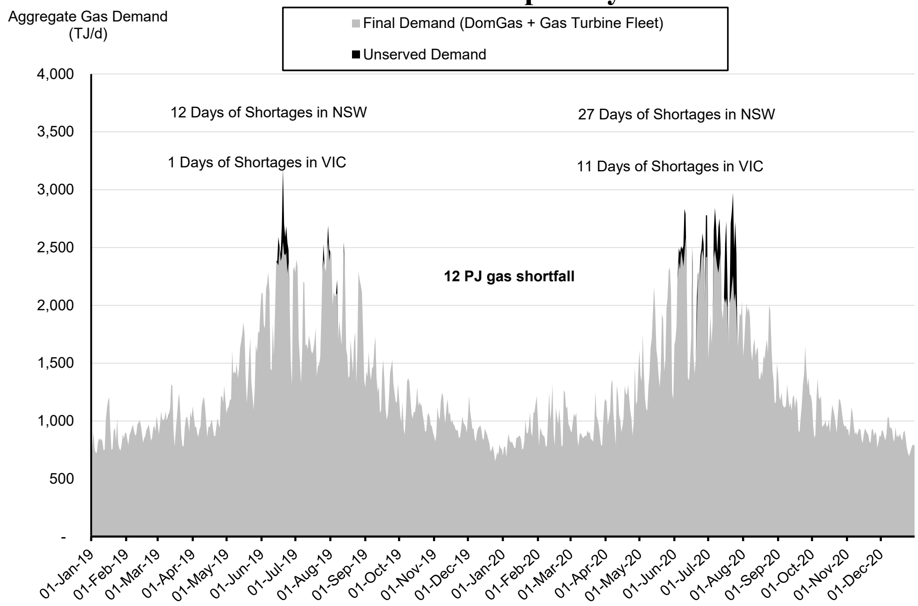


5.2 Impact of low-cost batteries and low-cost pumped hydro

The electricity market scenario with the most batteries and pumped hydro installed, and therefore the lowest annual reliance on gas turbine plant (at 135PJ/a) in the post-coal environment appears as 'Model 2' in Figure 3. In this scenario, gas turbine capacity equates to 11GW, some 5GW less than the 'Model 1' scenario in Section 5.1. GPE Model results for this scenario are illustrated in Figure 13.

The first point to note from Figure 13 is that the restructuring of the electricity market supply side materially reduces the frequency and intensity of strains placed on the gas market – far more than the number of Unserved Demand critical event days might suggest. Measured unserved demand across the two-year window reduces by ~80%, from 57 PJ to 12 PJ. Furthermore, the cumulative critical event days reduce by 65% from 143 to 51 days. However, Unserved Demand has not been eliminated and the source is once again constraints associated with the Moomba to Sydney Pipeline (~55 days per annum), Longford to Melbourne pipeline (~12 days per annum), South-West Pipeline (Port Campbell to Melbourne, ~26 days per annum), and the Southwest Queensland and QSN Pipelines (10-20 days per annum).

Figure 13: Low-Cost Batteries and 3PC Pumped Hydro scenario

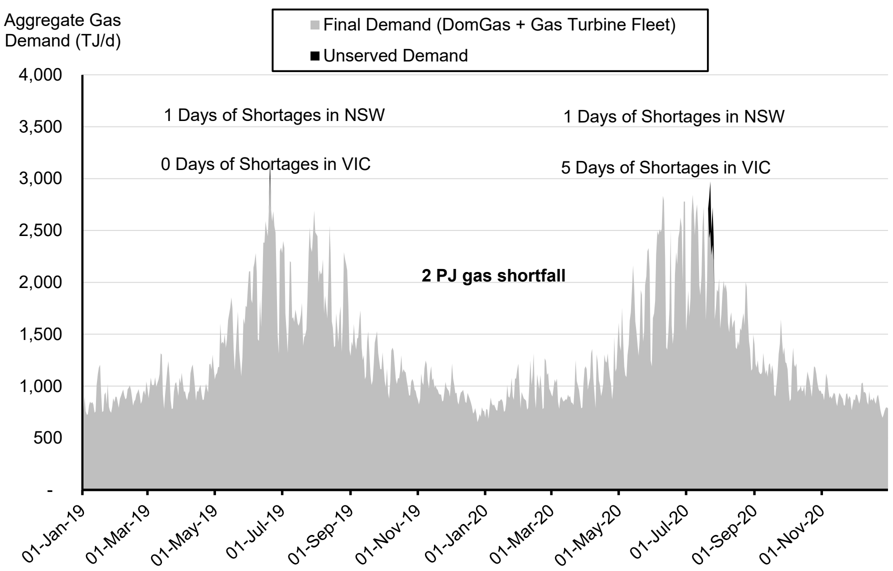


5.3 Adjusting pipeline capacity

Given residual episodes of Unserved Demand in Figure 13, our next scenario alters specific pipeline capacities (SWQP and QSN in Queensland, MSP in NSW and SWP in Victoria) by ~200TJ/d each. The cost of such augmentation would exceed $2 billion.

Two primary benefits follow. First, with better pathways gas storages prove to be more durable throughout the winter months, albeit still being exhausted prior to winter's end (see Appendix 1, Figure A-2). Second, critical event days are largely eliminated and year 2 exhibits single-digit event days at the end of winter.

Figure 14: Solving for 'y' – pipeline augmentation with 3PC pumped hydro



5.4 Timing of critical event days

Our final analysis tries to identify at what point the eastern gas market is likely to begin experiencing distress – noting the current market operates in equilibrium throughout the year. We return to scenarios from Gilmore (2024) which assess gas market loading *during* the coal plant exit phase. Specifically, we run the numbers for 10GW of coal (Model 11 scenario in Fig.3) and 5GW of coal (Model 12 scenario in Fig.3) remaining in-service.

With 10GW of coal remaining in service (Figure 15), there is only a single event day in NSW >100TJ in each of years 1 and 2. These critical event days may be adequately resolved through better (dispatchable) plant scheduling, drawing on linepack, or both. Augmentation of pipelines from Wallumbilla through to Moomba (in anticipation of further coal exit) would clear all imbalances.

Figure 15: 10GW of coal-fired generation plant in service

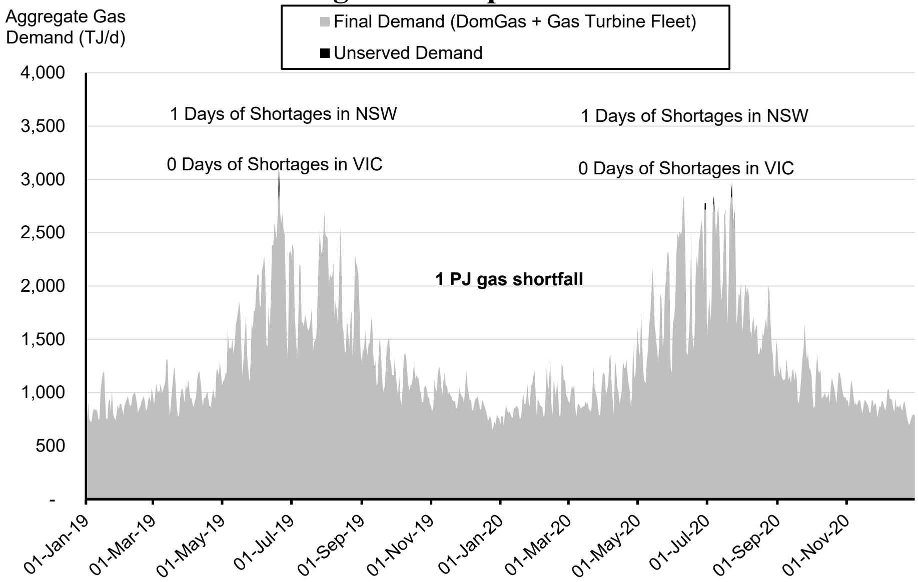
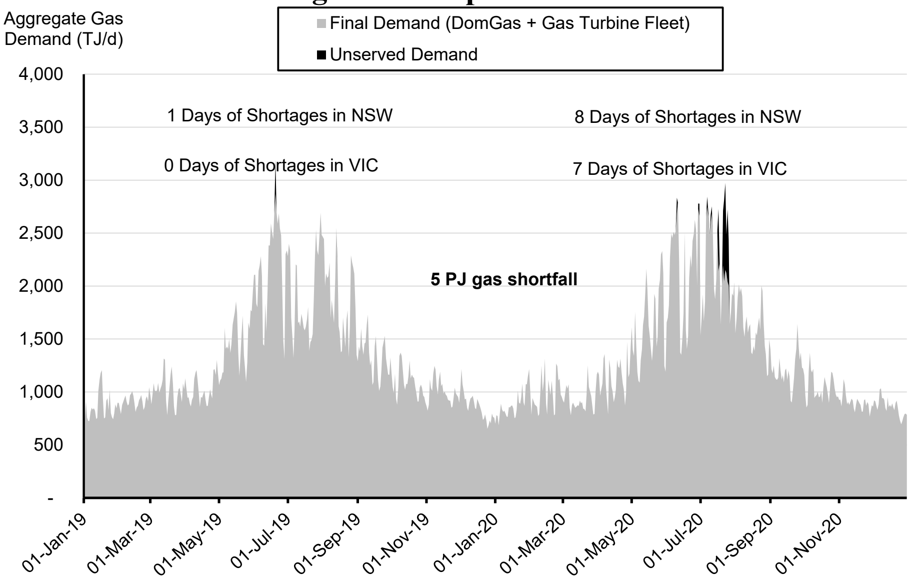


Figure 16 shows that with 5GW of coal remaining, there is a modest rise in critical event days in the second year, largely due to storages being exhausted before the end of winter and pipeline congestion consistent with that in Figure 13, albeit with less intensity. This suggests gas market problems may begin to amplify with less than 5GW of coal plant in service.

Figure 16: 5GW of coal-fired generation plant in service



6. Policy implications

In our modelling, we have held the gas market constant, and virtually upended the electricity market. And so at one level, it should not be surprising that unserved gas demand emerged as a result. Prima facie, one would expect both markets to develop in tandem. However, a closer look at policy settings makes this less obvious. First, two NEM jurisdictions have announced aggressive policies to electrify residential gas demand (see for example Hammerle and Burke, 2022)[6]. Second, the Commonwealth Government's Capacity Investment Scheme excludes gas turbines[7]. Third, the Australian Energy Regulator[8] has initiated a review of the form of regulation for the South West Queensland Pipeline – one of the most constrained in our model – which has resulted in the owner suspending plans for its augmentation.[9] And finally, following the turmoil experienced in the electricity market during 2022, the Commonwealth Government imposed an arbitrary price cap on the wholesale price of natural gas at $12/GJ (see Flottmann, 2024). Taken collectively, these policy signals must surely *weigh* on gas market investor sentiment. Indeed, for several years now the Australian Energy Market Operator has signalled looming shortages – and such warnings remain in force at the time of writing[10].

The potential for episodic, unmitigated demand shocks from the NEM's emergent gas turbine fleet is not in anyone's interests. Gas prices would be pushed higher, infrastructure capacity necessarily increases but utilisation rates may fall, and in worst-case scenarios, security of supply would be tested and likely breached in the markets for gas and electricity simultaneously. So what are the key observations and policy implications arising from our research? We would suggest the following:

- All forecasts by all modellers exhibited material dispatchable firming duties for the NEM's emergent gas turbine fleet following exit of the coal plant, with a notable intensity during the winter months of June and July. This aligns with well-documented winter season depressions in NEM renewable energy output due to lower solar irradiation and east coast wind speeds.

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[6] See also the Victorian Gas Substitution Roadmap at Help Us Build Victoria's Gas Substitution Roadmap | Engage Victoria
[7] See Capacity Investment Scheme - DCCEEW
[8] See https://www.aer.gov.au/news/articles/communications/consultation-opens-form-regulation-review-south-west-queensland-pipeline
[9] See https://www.apa.com.au/globalassets/asx-releases/2024/fy24-annual-report.pdf
[10] See https://aemo.com.au/-/media/files/gas/national_planning_and_forecasting/gsoo/2024/2024-gsoo-release-webinar.pdf?la=en

- We found episodic gas demand shocks during winter periods to be *highly problematic* for our model of the east coast gas market. If short duration batteries and/or intermediate duration pumped hydro plant were underweight, conditions deteriorated. Diversifying the firming task across a fleet of low-cost batteries, pumped hydro and gas turbines improved conditions considerably. Yet gas turbine duties still placed residual pressure on the market for natural gas during winter.

- Certain gas pipelines placed critical constraints on gas turbine operations during critical event days in NSW and Victoria. While some level of augmentation will alleviate some of the unserved load events, it is not immediately obvious through our model or inspection of Table 3 that augmentation of pipelines is viable for eliminating all events. This is ultimately a peak load problem and capital-intensive augmentations from Wallumbilla to Sydney (2200km) and further again for Melbourne for sporadic use is most unlikely to be economic. This suggests fuel supplies closer to loads, additional storages and alternate fields will be critical.

- Our model does not deal with gas pipeline 'linepack' (i.e. gas stored and available for use in pipelines) and this is to be acknowledged as an important modelling limitation. Prima facie, this limitation suggests we may have *overstated* the extent of the problem to be solved.

- On the other hand, our model did not examine the frequency of Maximum Hourly Quantity events. We focused only on the Maximum Daily Quantities demanded. As it turns out, the frequency of critical Maximum Hourly events occurs at ~19x the rate of Maximum Daily events (see analysis in Figure A-3, Appendix I). This suggests we may have *understated* the problem to be solved.

- Policy solutions need to commence investigations into additional storages, storable fuels and fuel sources located closer to the problem epicentre – Sydney and Melbourne. This may come in an array of formats including new gas storages, additional linepack, liquid (diesel) fuels and a requirement for all new gas turbines to be commissioned as 'dual fuel' plant.

- Axiomatically in the long run, the operation of gas turbines using natural gas is inconsistent with a policy of net zero emissions. Gilmore et al.,(2023) show that even at high fuel cost of hydrogen ($50/GJ), gas turbines remain critical to reliability given our current understanding of intermittent renewables and storage costs (see also Mountain, 2024).

7. Concluding remarks

Energy markets need to *transition to renewables*, not collapse due to poor structural adjustment planning. Structural adjustment of the NEM's supply-side involves the progressive exit of 30GW of coal-fired power stations, a process which commenced from 2012. Continuous entry of intermittent renewables (via shareholder and supply chain pressures) are driving coal exit, but reliability of supply requires that its capacity be replaced by a fleet of dispatchable assets, specifically, short duration batteries, intermediate duration pumped hydro and fuel based turbines as the last line of defence or *'capacity of last resort'*. While these firming assets compete against each other at the margins it is broadly accepted that no single generation technology can cost effectively mitigate intermittency, maintain grid stability and ensure security of supply (Javed et al., 2020; Gilmore et al., 2023;

Simshauser and Gohdes, 2024). In other words, a portfolio is required and our modelling revealed why this is the case vis-à-vis gas turbines.

We collated a series of market forecasts by market modellers with a special interest of the role played by gas turbines as the *capacity of last resort* in the latter- and final-stages of coal plant exit. We found episodic surges in gas turbine activity during winter months when renewable output experiences cyclical lows. When we tested gas turbine activity in a dynamic partial equilibrium model of Australia's eastern gas market, we found the potential for significant unserved demand during critical event winter days. The problem was prominent in NSW and Victoria.

Model results tend to suggest that the timing of the problem is likely to arise as the NEM's coal generation fleet falls to 5GW. As with all complex problems, resolution requires an array of policy responses and investment initiatives. The NEM's coal fleet is currently ~20GW and so sufficient time exists to identify and develop the mitigating set of assets – viz. a well-diversified firming fleet comprising batteries, pumped hydro and gas turbines to optimise gas use. And for the gas market itself, marginal network augmentations, additional gas storage and ensuring new gas turbines are dual-fuel and are able to be fired on other forms stored fuels.

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APPENDIX I

Table A1: Historic Gas Demand (2009-2023) vs 2035 Results (from the 12 Models)

Historical Market Results				Forecasts for 2035		
2009	156	976		Model 1 F'cast*	194	3,333
2010	192	837		Model 2 F'cast**	135	2,557
2011	190	1,135		Model 3 F'cast	233	2,316
2012	200	823		Model 4 F'cast	171	2,052
2013	189	874		Model 5 F'cast	232	2,167
2014	212	1,138		Model 6 F'cast	223	2,561
2015	168	858		Model 7 F'cast	117	2,614
2016	144	817		Model 8 F'cast	191	2,240
2017	196	1,022		Model 9 F'cast	274	2,656
2018	147	837		Model 10 F'cast	232	2,167
2019	176	1,171		Model 11 F'cast	93	2,109
2020	139	1,120		Model 12 F'cast	157	2,849
2021	112	892				
2022	131	984				
2023	93	713				
Average	163	946		Average of Models	188	2,008
Maximum	212	1,171				

* No Pumped Hydro. This scenario was used in Section 5.1 (see Fig.11-12)

**Low Cost Batteries and '3PC' pumped hydro. This scenario was used in Section 5.2 (Fig.13)

Figure A-1: Gas Storage Balances – no pumped hydro scenario

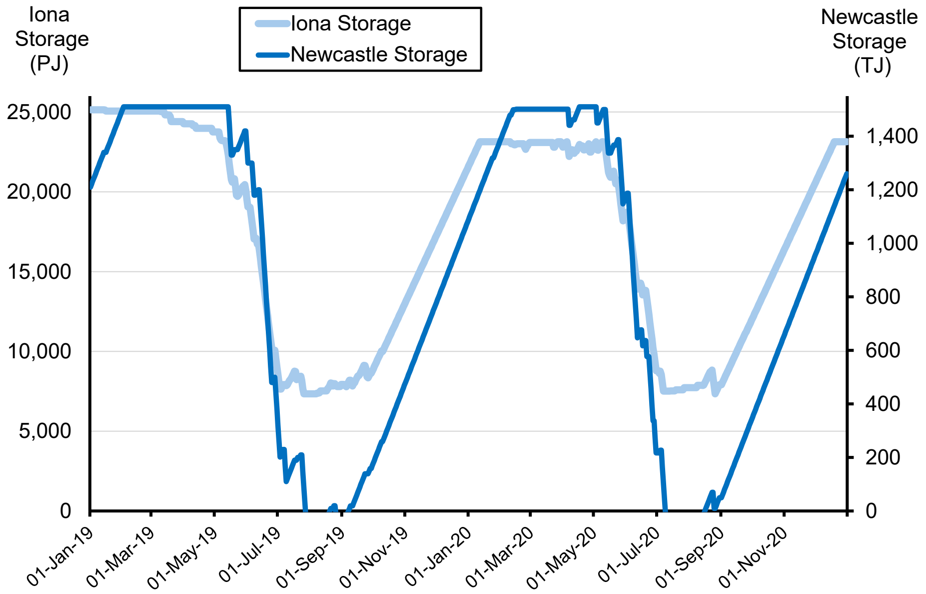

Figure A-2: Gas Storage Balances – adjusted pipeline scenario (vs no pumped hydro)

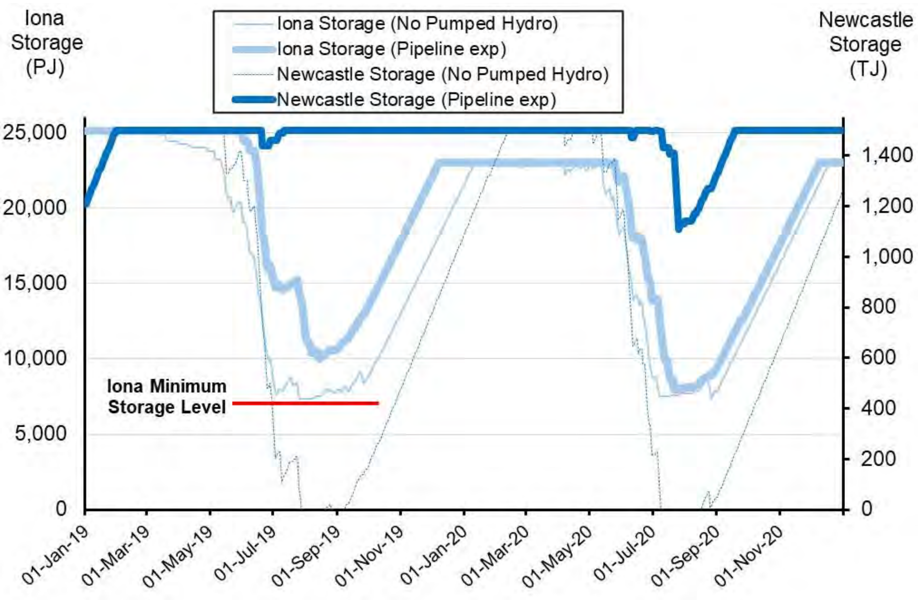

Figure A-3: NSW Gas Load Duration Curve: Daily vs Normalised Hourly Max. Quantity