Attachment 6.2

CarbonTP Expert Report Underpinning Future of Gas

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CARBON TRANSITION PATHWAYS

Long run demand modelling for the Dampier to Bunbury Natural Gas Pipeline

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List of Abbreviations

ACCU	Australian Carbon Credit Unit
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AGIG	Australian Gas Infrastructure Group
APA	APA Group
ARENA	Australian Renewable Energy Agency
AU	Australia
AUD	Australian Dollars
BAU	Business As Usual
BESS	Battery Energy Storage System
BEV	Battery Electric Vehicle
CAGR	Compound Annual Growth Rate
CBAM	Carbon Border Adjustment Mechanism
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage/Sequestration
CCUS	Carbon Capture, Utilisation and Storage/Sequestration
CIS	Capacity Investment Scheme
CMD	Contracted Maximum Demand
CPG	Coal Powered Generation
CRC	Certified Reserve Capacity
CSBP	Cuming Smith British Petroleum and Farmers Limited
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DCCEEW	Department of Climate Change, Energy, the Environment and Water
DER	Distributed Energy Resources
DRI	Direct Reduced Iron
EIB	European Investment Bank
EPA	Environmental Protection Agency
ESOO	Electricity Statement of Opportunities
ETS	Emissions Trading Scheme
EU	European Union

EV	Electric Vehicle
FX	Foreign Exchange
FY	Financial Year
GJ	Gigajoule (1 x 109)
GPG	Gas Power Generation
GSOO	Gas Statement of Opportunities
GW	Gigawatt (1 x 109)
GWh	Gigawatt hour
HBI	Hot Briquetted Iron
HHV	Higher Heating Value
IRCR	Individual Reserve Capacity Requirement
IRR	Internal Rate of Return
LCOE	Levelised Cost of Electricity
LGC	Large-scale Generation Certificate
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
MDEA	Methyldiethanolamine
MVR	Mechanical Vapour Recompression
MW	Megawatt (1 x 106)
MWh	Megawatt hour
OCGT	Open Cycle Gas Turbine
PJ	Petajoule (1 x 1015)
PPA	Power Purchase Agreement
RCM	Reserve Capacity Mechanism
RCT	Reserve Capacity Target
REGO	Renewable Electricity Guarantee of Origin
RET	Renewable Energy Target
RTE	Round Trip Efficiency
SRMC	Short Run Marginal Cost
STC	Small-scale Technology Certificate
SWIS	Southwest Interconnected System
TJ	Terajoule (1 x 1012)
TPA	Third Party Aggregator
TRL	Technology Readiness Level
TW	Terawatt (1 x 1012)
TWh	Terawatt hour
US	United States
VPP	Virtual Power Plant
VRE	Variable Renewable Energy
WA	Western Australia
WEM	Wholesale Electricity Market

Executive Summary

There is likely to be a reduction in demand for gas volumes through the Dampier to Bunbury pipeline out to 2050 and beyond. The magnitude of this reduction is difficult to predict. Of no lesser significance is the anticipated change in utilisation patterns which together with the reduction in throughput may justify an adjustment to the tariff and impact how the pipeline is operated in the longer term. It is anticipated steady demand for gas will progressively be replaced by more erratic demand, with very high peaks driven by gas power generation during sustained periods of low renewables output.

Drivers of Dampier to Bunbury Natural Gas Pipeline (DBNGP) demand

The primary shippers of gas through the DBNGP are the power generation industry, alumina refining industry and chemicals and gas processing industry.

Between them these three industries account for ~470 TJ/d of throughput with respective shares of, 35%, 60% and 5% of the total which is ~80% of contracted capacity.

There are many variables which could impact the future demand for gas both in terms of total volume shipped and peak capacity requirements. The most influential of these variables are considered to be gas price, carbon price and electricity price, which is itself influenced by gas price. Together with relevant global commodity prices and technical readiness of electrification technologies these factors will influence the economics of electrification and continued commercial viability of industrial operations.

Each of the key variables will be heavily influenced by policy, for gas price the primary policy driver is the WA Domestic Gas Reservation Policy. For carbon price the Safeguard Mechanism is the key driver but the EU Carbon Border Adjustment Mechanism (CBAM) is also relevant and other countries may start to introduce carbon pricing and import taxes. Electricity price has multiple influences, but from a policy perspective, the Federal Government Capacity Investment Scheme (CIS), and state government environmental approval legislation are key influences on the speed, scale and cost of renewables build out which will directly influence price.

Out to 2050 the possible outcomes range from a stable demand, with reductions in some industries being offset by new sources of demand and increments in power generation, to a substantial reduction in demand resulting either from electrification of industry and large scale build out of renewables and storage and/or deindustrialisation due to unfavourable macro-economic conditions.

Range of outcomes

There is a range of potential decarbonisation pathways for WA with different implications for DBNGP utilisation both in terms of use patterns and volumes consumed. Here we have tried to consider a broad spectrum of conceivable influences to explore the fullest extent of outcomes primarily driven by domestic gas policy and government support for renewables, with sensitivities around a large span of carbon prices. These are manifested in three distinct schemes effectively defined by the speed and magnitude of renewable generation and energy storage additions to the SWIS.

1. **Base Case**
   Aligned with the Federal Government Capacity Investment Scheme incentives and a successful intervention in domestic gas policy.
2. **Medium Case**
   Aligned with the Australian Energy Market Operator (AEMO) reserve capacity requirements and a partially successful intervention in domestic gas policy.
3. **Accelerated Case**
   Aligned with a sustained high level of government intervention in renewables build out, and a failed intervention in domestic gas policy.

The cases are covered in more detail below.

The Base Case
Gridcog Scheme 1

In the base case there is potential for an increase in total gas demand to 2050

Little or no reduction is anticipated prior to 2035 with a more likely scenario being an increase in demand primarily driven by retirement of coal fired power generation, South32 switching from coal to gas and CSBP constructing a new ammonia plant. Some of this increase will be partially offset by growth in renewable generation, however the projections for renewables indicate they will be insufficient to cover both the anticipated growth in load and retirement of coal. New gas generation capacity is likely to be required to provide both adequate capacity to meet demand, and sufficient redundancy to ensure security of electricity supply.

Beyond 2035 the electrification of industry would remain commercially challenging due to sustained low gas prices and a reduction in industrial gas demand is considered unlikely without a significant increase in carbon prices or government intervention.

This case would strongly favour CCS as a decarbonisation solution which would support continued gas demand in the long term.
With little or no reduction in industrial gas demand and increased demand from power generation, the net impact overall would be to increase total gas demand ~10-20% above where it is today by 2031 when all coal is retired, and by up to ~25% by 2050 .

The Medium Case
Gridcog Scheme 2

In the Medium case there is potential for a modest reduction in gas demand to 2050.

Gas demand follows a similar profile to the base case out to 2035, although higher growth in renewables helps reduce demand for power generation by up to 80 TJ/d over the base case.

Between 2035 and 2040 demand is expected to start to decline due to electrification of industry and continued build out of renewables and storage. The first major industrial switch from gas to electricity is likely to be steam generation for alumina digestion, either through Mechanical Vapour Recompression (MVR) and/or electric element heating coupled with thermal storage, although when/if this occurs will be strongly driven by relative economics. Some of this reduction will be offset by increased demand for gas power generation to provide firming for the additional electricity consumption. This will result in a changing pattern of gas demand with lower stable volumes coupled with higher demand peaks.

Between 2040 and 2050 further reductions in stable demand are anticipated through alumina calcining either switching to electricity (considered most likely) or green hydrogen (less likely). If electrification is the favoured solution, it is likely some of the reduction will be offset by increased demand for gas fired electricity firming.

Additionally, by 2030 it is anticipated CSBP may have two ammonia plants online with two primary decarbonisation solutions available to them, Carbon Capture and Storage (CCS), or green hydrogen. Only green hydrogen would result in a reduction in gas demand and is currently considered to be the less likely option due to a challenging cost structure.

Beyond 2050 it is anticipated demand for gas will continue to decline as renewable costs continue to come down, making installation of excess capacity with higher levels of curtailment commercially competitive, especially in the face of higher carbon prices putting cost pressure on fossil fuel generation.

As the percentage of renewable energy in the grid increases, together with the overall load, the pattern of gas demand for electricity firming will change, migrating towards higher peaks with stable or decreasing average demand which has implications for capacity contracting and how the pipeline may be used in future.

Accelerated Case – Gridcog Scheme 3

The primary differences between the medium and accelerated cases are the degree to which gas firming is used to supply the grid and the speed of industrial electrification driven by high gas and carbon prices. At its limit this case could result in annual average gas demand in 2050 of <200 TJ/d based on all industry being electrified and gas power generation supplying only ~10% of the SWIS total annual electricity demand.

Accelerated build out of renewables and storage reduces the amount of electricity generated by gas. Deployment of Gigawatt scale offshore wind coupled with accelerated deployment of onshore wind and solar together with large quantities of longer duration storage could result in gas contributing only ten percent of power generation in 2050. Short term peak demand is also reduced as the excess renewables capacity and large quantities of storage are sufficient to manage intraday peaks, although reduced renewables output in winter will still require a large amount of gas firming capacity for several consecutive days.

Additional considerations

Down-side risks

Deindustrialisation is a possible outcome if decarbonisation is not commercially viable for the major shippers. Slower than anticipated cost reductions in renewables, high domestic gas prices, a high carbon price and lower commodity prices with the absence of a green premium emerging, could make continued operations commercially unviable. This may lead to temporary or permanent curtailment of production rapidly removing the gas demand associated with the affected industry.

It should be noted that a combination of both de-industrialisation and accelerated build out of renewables is considered highly unlikely as for large scale accelerated renewables deployment to occur low costs would be needed, supporting increased demand from electrification of industry, which could therefore be assumed to remain commercially viable.

Up-side

There is potential for DRI production in the mid-West given the renewables and magnetite resources in the region and, with the concentration of alumina production in the Southwest, it is not unreasonable to assume a low emissions aluminium smelter could make sense if sufficient low-cost renewable electricity could be made available.

A single world scale DRI plant could add up to 80 TJ/d (~10-15%) to firm capacity from 2030+ which could be progressively displaced by green hydrogen over the subsequent decade(s).

A world scale aluminium smelter could add up to 200 TJ/d of peak demand during periods of low renewables output. However, contracting this capacity annually when it is likely only 10-20% of it would be used might not be commercially attractive based on the current tariff arrangement and would negatively impact the economics of the project.

Patterns of demand

Electrification of industry would replace a steady demand for firm capacity gas with a much more variable demand for gas power firming. This would likely result in an overall reduction in contracted capacity from industry, however, the peak demand in periods of low renewables output, is likely to increase driven by gas power firming and may exceed the instantaneous capacity of the pipeline. To guarantee availability of power at peak times, peaker gas turbine operators may need to contract their maximum demand for the full year whilst only using it on a handful of occasions. This would significantly raise the effective cost per gigajoule of gas consumed with a knock-on impact on the spot electricity market prices. It would also be difficult to contract gas volumes from suppliers on this basis.

The shift in demand patterns and requirement for underutilised firm capacity is likely to drive pipeline users towards alternative solutions such as localised fuel storage to cover peaks, e.g.,

- Gas storage is expanded to smooth out short term peaks. Taking this to its natural conclusion would result in gas peakers being built with integral gas storage near to a large renewable generator to maximise grid capacity utilisation. Depending on the origin of the gas this might bypass the pipeline completely.

The above outcomes may reduce Capacity Reservation Tariff revenue requiring an increase in the tariff to cover costs. However, depending on the level of renewables penetration there is likely to remain a requirement for significant gas power generation in the winter driven by seasonal differences in renewables output. Covering several weeks of high demand with storage is unlikely to be economically viable and would require significant contracted capacity to ensure adequate power could be made available.

> "The shift in demand patterns and the requirement for underutilised firm capacity is likely to drive pipeline users towards alternative solutions such as localised fuel storage to cover peaks."

Introduction

CarbonTP are a WA based energy transition consultancy with a specific focus on hard to abate industries with practical local knowledge and expertise gained in project development and consulting interactions across a range of industries and energy transition themes including:

- Oil and gas production
- Carbon Capture and Storage (CCS)
- Hydrogen production (Green, blue and grey)
- Green steel production (Recycling and HBI)
- Alumina production
- Renewables and energy storage development
- ACCU generation

For this work CarbonTP partnered with Sunrise Energy Group to provide expertise in electricity supply modelling and help with understanding future gas demand for power generation in the Southwest interconnected System (SWIS).

CarbonTP were contracted by Australian Gas Infrastructure Group (AGIG) to model possible future gas demand profiles for the DBNGP based on a coherent narrative and logic using data provided by AGIG and other publicly available data together with our understanding of large local gas consumers and the decarbonisation technologies relevant to them.

The purpose of the modelling was to establish a diverse range of future gas demand profiles and use patterns together with an understanding of what would drive them, and to establish how this might impact usage of the DBNGP and the relative contribution of the tariff to the overall cost of delivered gas.

With an understanding of how the contribution of the tariff to the cost of delivered gas may change over time, AGIG can determine if adjustments to the tariff are justified to ensure any potential impacts are moderated.

Document structure

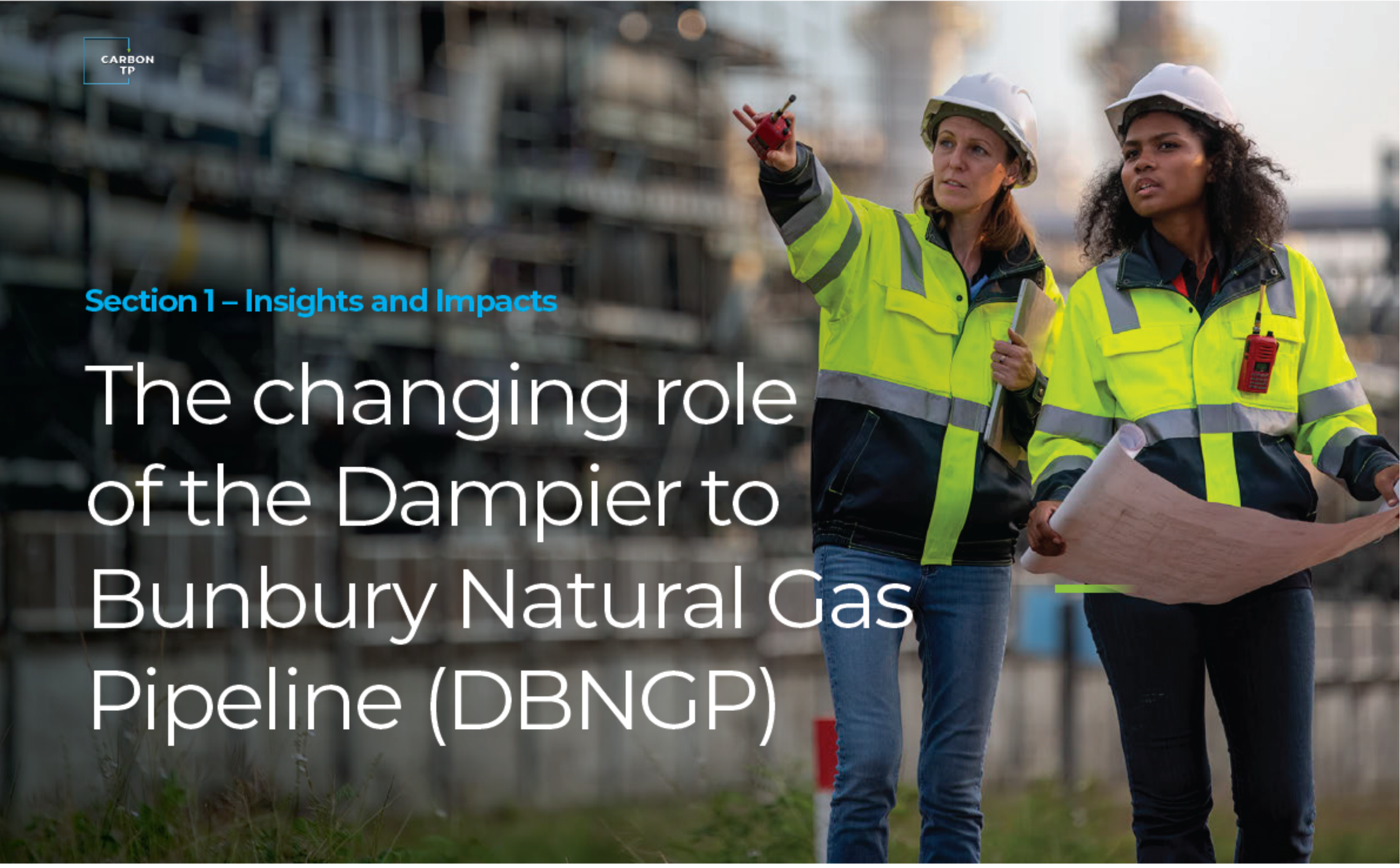
The document is divided into the following sections:

Section 1 – Insights and Impacts

- **The changing role of the Dampier to Bunbury Natural Gas Pipeline (DBNGP)** – This provides an overall description of the current role of the pipeline, contrasted with the future role of the pipeline and how this interacts with power generation and the development of the SWIS.
- **Summary of factors and impacts on gas demand** - This provides an objective summary of the key factors and impacts in relation to the main shippers of gas both now and in the future.
- **Analysis of key industrial shippers** – This provides an overview of the main gas shippers and their decarbonisation commitments together with an in depth exploration of the options they have to decarbonise and how these might affect gas consumption and demand profiles.

Section 2 – Modelling details and outputs

- **Approach to Modelling** – This section describes at a high level the approach that was taken to model the gas demand and the rationale for how the modelling was performed.
- **Modelling Process** - Stages of development – This section describes the steps taken to:
  - Identify gas shippers material to DBNGP revenue.
  - Identify and define influencing factors, input variables and contextual factors relevant to gas consumption.
  - Develop input variable profiles corresponding to different contextual factor outcomes.
  - Construct cases representing possible futures for the SWIS power generation assets.
  - Model the SWIS for each case using Gridcog software to forecast GPG gas demand.
  - Develop electricity price calculations based on input variables.
- **Modelling electricity demand to forecast gas power generation** – Details of Gridcog model This section describes in detail how the modelling of the gas demand for power generation was undertaken with subsections describing each of the schemes used to define the model inputs together with the results of the modelling.
- **Gas demand for GPG** – Model Insights – This section details the key outputs and insights from the Gridcog modelling regarding gas consumption patterns for power generation out to 2050.



Section 1 – Insights and Impacts

The changing role of the Dampier to Bunbury Natural Gas Pipeline (DBNGP)

Summary

The role of the DBNGP will change over time, migrating from one of providing a stable supply of gas to industry with some baseload and peaker power generation, to one of ultimately providing access to gas to firm power generation. As coal retires the role of gas generation will become more of a baseload provider before progressively returning to filling in peaks in demand and troughs in renewables generation. This pattern will be driven by electrification of industry shifting energy demand from the DBNGP to the SWIS, with progressive penetration of renewables in the SWIS driving gas from a base load generator, replacing coal, to a peaker service. With the forecast electricity load growth, it is possible future peak demand for GPG may exceed the instantaneous capacity of the DBNGP to deliver, although overall utilisation (annual throughput) is expected to remain stable or decline.

Without intervention the contribution of the tariff to the cost of gas delivered could increase, incentivising shippers to seek alternative solutions for energy and compounding the problem.

Appropriately managed, the DBNGP will be an integral part of the energy transition for WA, providing reliable low cost access to gas from the North and Perth Basin to gas power generators serving the SWIS.

Current state

Industry

The major industrial shippers currently consume gas at a relatively stable and predictable rate. Their optimal capacity contracting strategy has been one of over contracting by a small margin to ensure the required quantity of gas is supplied under all circumstances, e.g., in the event of a supplier production outage. The industrial shippers therefore use a high percentage of their reserved capacity, keeping their tariff costs per GJ relatively low compared to the cost of the gas they are purchasing.

The SWIS

The gas generators in the SWIS use a combination of capacity contracting strategies to cover baseload demand based on long term forecasts, and peak demand based on short-term forecasts. At the moment the pipeline capacity is sufficient to meet overall peak gas demand for industry and power generation combined, and therefore power generators can be relatively certain they will be able to contract sufficient capacity as necessary. However, that situation is likely to change.

The Pipeline

The DBNGP currently supplies ~1,000 TJ/d gas, primarily from the North of the state, but also from the Perth Basin to the Perth metro area, Pilbara, Mid West and South of Perth. The total supply equates ~600 TJ/d of full-haul equivalent *(explanation of the tariffing arrangement is provided below).*

The capital depreciation and cost of operating the line is recovered through a Reference Tariff which is currently a relatively small proportion of the cost of the gas delivered due to the high utilisation of the pipeline spreading this cost over >350 PJ/yr of delivered gas.

The Reference Tariff is comprised of a Capacity Reservation Tariff and a Commodity Tariff. The Capacity Reservation Tariff is paid to reserve capacity in the line 365 days per year, irrespective of whether that capacity is used on any given day or not, and the Commodity Tariff is paid per gigajoule of gas shipped through the pipeline. The tariff split is currently ~95:5 fixed:variable based on the approximate fixed:variable cost split as estimated by the regulator. The tariffs are scaled in proportion to the distance the gas has travelled through the pipeline with the maximum Full Haul distance being defined as 1,399 km and applicable to gas supplied in the North and delivered to Perth and further South.

Currently ~60% of the line capacity is taken up by annual capacity contracts with large industrial shippers and the power generation sector. The annual contracts can include variance from month to month to accommodate seasonal variation in demand. The remainder of capacity is reserved on an interruptible service basis and in the day ahead spot capacity market. Only those shippers with annual capacity contracts are guaranteed to be supplied with their contracted quantity of gas at all times.

At the present the total full haul tariff is ~$1.42/GJ comprised of:

- Capacity Reservation Tariff ~$1.34/GJ/day
- Commodity Tariff ~8.3 c/GJ

For a shipper reserving capacity in the line to guarantee availability of supply at all times, their effective tariff per gigajoule of gas delivered will depend on their utilisation of the capacity reserved, e.g., assuming a gas price of ~$9/GJ:

- At 100% utilisation the tariff would be $1.34 + 0.08 = $1.42/GJ delivered or ~16% of the cost of the gas
- At 80% utilisation the tariff would be $1.34/0.8 + 0.08 = $1.76/GJ delivered or ~20% of the cost of the gas.

At the present the total full haul tariff is ~$1.42/ GJ comprised of:

~$1.34/GJ/day

Capacity Reservation Tariff

~8.3 c/GJ

Commodity Tariff

Assuming a gas price of ~$9/GJ:

~16%

At 100% utilisation the tariff would be $1.34 + 0.08 = $1.42/GJ delivered or ~16% of the cost of the gas

~20%

At 80% utilisation the tariff would be $1.34/0.8 + 0.08 = $1.76/GJ delivered or ~20% of the cost of the gas.

Future state

Industry

If industries switch from gas to electricity, with the majority supplied by Power Purchase Agreements (PPAs) with renewable generators and storage providers, the role of gas in industry will transition from one of a baseload energy provider, with firm contracts and stable demand, to one of providing gas powered electricity firming to bridge the gaps in renewables generation.

Under such circumstances it is probable industrial shippers would relinquish some, if not all, of their firm pipeline capacity which currently accounts for approximately two thirds of contracted full haul capacity.

The more regular and predictable gaps in renewable generation driven by diurnal and seasonal patterns are likely to be managed through additional PPAs with gas fired power generators, thereby replacing directly contracted gas capacity, with a reduced volume of indirectly contracted capacity used for power generation by a third party.

The more irregular gaps in renewable generation caused by unpredictable weather patterns will also need to be covered through purchasing electricity from the spot market. It is also possible that where industrial shippers have their own gas fired power generation or co-generation units, they will retain sufficient firm pipeline capacity to ensure the generator will be available when required. This is discussed in more detail under the sections on individual shippers.

In periods of very high electricity demand, those industrial users with the ability to do so, may also turn down their operations to load shed and participate in demand side management schemes which are likely to play a significant role in managing the grid in future.

Also noteworthy is that heavy industries such as alumina refining, operate 24/7/365, and will have a flat electricity demand profile which will be more difficult to meet with renewables and storage than a typical non-industrial user profile with the characteristic overnight dip in demand, and are therefore likely to require comparatively more gas firming.

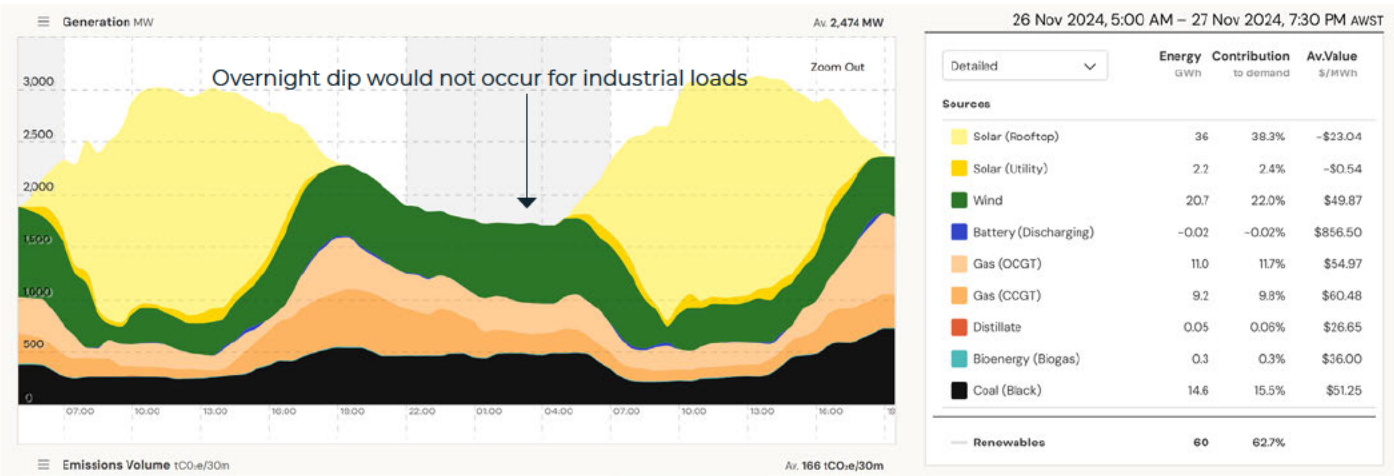


Figure 1 Example of typical current daily generation and load pattern in the SWIS (1)

The SWIS

In 2023 ~30% (6.3 GWh) of the electricity generated was from coal based generation. This is set to be fully retired by the end of 2030. Additionally, the total load is forecast to grow by ~100% over the next decade (See 2023 Wholesale Electricity Market (WEM) Electricity Statement of Opportunities (ESOO) Fig. 15) (2) with gas picking up a lot of the unserved load left by the coal retirements.

> *Note: Potential development scenarios and a more detailed discussion of the future of the SWIS are covered in detail under the section "Modelling electricity demand to forecast gas power generation – Details of Gridcog model"*

As the total load on the SWIS grows, the peak GPG capacity required to meet that load will also increase. Our SWIS modelling indicates that by 2035 peak GPG capacity of 4,000 MW may be required and this load does not include any electrification of heavy industry. The gas demand to generate 4,000 MW is ~1,000 TJ/d which, on its own, is approaching the maximum operational capacity of the pipeline. It is therefore anticipated that alternative solutions may be required to serve short term peaks, such as local gas or distillate storage.

The net effect of electrification on the pattern of gas demand will therefore be to progressively tie it to GPG generation profiles which will be dependent on renewable generation profiles in combination with load profiles. As industry electrifies and more renewables connect to the SWIS the total volumes of gas consumed will gradually decline while the demand peaks are likely to follow a steep upwards trajectory to meet a rapidly increasing load on the SWIS when renewable output is low.

Further into the future it is possible the peak demand for electricity firming may exceed the capacity of the pipeline to deliver.

The pipeline

We have established pipeline utilisation in the future is likely to be lower with peak capacity demand being higher and that the pipeline may be unable to service this peak. Without intervention, the net result of this will be an increase in the delivered cost of gas either through higher tariffs and/or lower utilisation of reserved capacity.

For example: A 200 MW GPG operator may need absolute certainty that they can access 50 TJ/d in case of a period of low renewable generation, but it is unlikely they will know well in advance when they need this capacity.

To ensure they are always able to supply power to meet such peaks in demand they would need to contract their peak capacity requirement on an annual basis as there are no guarantees that day ahead spot capacity will be available to them. However, they may only need their absolute peak capacity on a handful of days over the year.

With the current tariff arrangement, and assuming the same $9/GJ gas price as above, the implications of this are:

~750%

At 2% utilisation (~7 days per year) the tariff would be $1.34/0.02 + 0.08 = $67.08/GJ delivered or ~750% of the cost of the gas.

The above situation implies an average price per Gigajoule of gas consumed for peak generation of ~$76. With the potential limits on the pipeline's capacity to supply peak demand this would provide further incentive for power generators to look for alternative solutions such as local fuel storage. Diesel, or distillate, is a current solution to meeting extreme peaks in demand and we have calculated $76/GJ would be equivalent to a diesel price of ~$3.00/L on an energy equivalence basis, although this does not include for the capital costs of building a diesel storage facility or the cost of operating it and holding sufficient inventory to meet peak demand.

However, it is possible diesel storage or some alternative fuel storage could be a practical alternative to meeting short term, high peaks in electricity demand. In future, generators may therefore look to store distillate, or alternative fuels, to provide the certainty of fuel supply they need, which would marginally reduce pipeline utilisation and exacerbate the problem.

An alternative, and potentially better, solution would be to locate GPG local to a gas storage facility, e.g., a partially depleted gas reservoir, and fill the storage with a steady and predictable flow of gas which can be quickly drawn down during periods of peak power demand. This would smooth out the peaks in demand for pipeline capacity, reducing the requirement for excess capacity reservation.

There is also the option of connecting new gas peaking capacity to the pipeline via an oversized lateral. At an estimated cost of ~$2 million per TJ of storage with an assumed 7 cycles per year the levelised cost of storage is estimated to be ~$35/GJ which is much lower than the cost of reserving sufficient annual capacity in the pipeline to meet the occasional peak.[1]

It is recognised that the pipeline itself can use line pack to provide some level of storage and smooth out differences between supply and demand, however this may not be sufficient to manage future variability. Another primary effect of the increasing price of delivered gas is increasing the price of wholesale electricity. At ~$76/GJ the fuel cost for an OCGT would be ~$840/MWhe. Whilst OCGTs will only be providing a relatively small percentage of the total generation and much of the delivered energy will be through bilateral contracts, it is anticipated that gas generation will be setting the spot market clearing price more frequently in future.

Longer term outlook

Beyond 2050 it is hoped that most industries that have the potential to move away from gas will already have done so although this is in no way guaranteed.

The demand for gas will then most likely be dominated by gas for power generation to firm renewables with a steady decline in volume but still maintaining high peaks during extended periods of low renewables output which will still occur albeit less and less frequently.

Based on the above the gas consumption beyond 2050 will depend on the total load on the SWIS and the degree to which that load is served by renewable generation.

In the accelerated case, by 2050 ~90% of the dispatched electricity in the SWIS is from renewables buffered by storage. With a forecast load of 53 TWh/yr, if only 10% of that is met by gas peakers, the annual average daily consumption would be ~150 TJ/d, although this would vary considerably throughout the day and seasonally. Projecting forward to 2060 with a load growth of 2% p.a. to 65 TWh and assuming growth in renewable and storage capacity results in only 5% of electricity being supplied by gas peakers, the annual average daily consumption would be only ~80-110 TJ/d

Without fully considering and planning for the impact changes in energy sources and consumption patterns may have, it is possible there will be a spiralling increase in the cost per gigajoule of delivered gas with the capacity charge dominating the cost. This is likely to incentivise shippers to find alternative solutions further reducing utilisation and compounding the problem. Additionally, shippers who are not pro-active could find themselves paying very high prices and without sufficient cashflows to invest in alternatives.

Therefore we believe that careful management of the pipeline and tariff in the interim years is essential to ensure the pipeline continues to deliver value for the State and provides the lowest cost solution to facilitating the energy transition rather than becoming a stranded asset.

1 Details of calculation can be found in the Excel file, "Storage cost assessment"

Section 1 – Insights and Impacts

Summary of factors and impacts on gas demand

This section provides an objective summary of the key factors and impacts in relation to the main shippers of gas both now and in the future. Primarily we looked at power generation, alumina refining and ammonia manufacturing, as the largest consumers of gas, to understand what could impact their gas demand over the next three or more decades.

Note: *Demand does not account for whether all or part of the gas is delivered through the DBNGP, or how far the gas travels through the DBNGP, both of which are important considerations from a revenue perspective. These issues are addressed in detail in AGIG's internal modelling using data from this report as inputs.*

Further details and justification for assumptions can be found under the following section, "Analysis of key industrial shippers".

Gas power generation

Key factors

1. Electricity demand growth
2. Renewables penetration in the grid

Impacts

Table 1 Summary of key data in relation to gas power generation for the Base and Accelerated renewables deployment cases, compared with the present day.

Metric	Accelerated (2050)	Base (2050)	Current (2023)
Renewables penetration (%)	90	70	34
Percentage of electricity generated by gas (%)	10	30	38
Total annual electricity demand (TWh)	53	53	21
Annual gas generation (TWh)	5	15	8
Average gas generation output (MW)	570	1,800	880
Average gas demand (TJ/d)	150	460	230
Peak gas generation (MW)	3,100	6,400	2,400
Peak gas demand (TJ/d)	820	1,700	630
Implied gas capacity factor (%)[2]	18	28	37

Beyond 2050 the ratio between average demand and peak demand is expected to continue to rise with continued growth in demand and greater penetration of renewables.

2 This is calculated as average output divided by peak output. In reality the capacity factor will be lower as there will need to be at least 120% of peak capacity available to allow for unreliability and maintenance.

Alumina refining

Key factors

1. Curtailment (Temporary or permanent shutdown of the facility)
2. Electrification of steam generation
   a. Mechanical Vapour Recompression (MVR)
   b. Electric element heating coupled with thermal storage (Not evaluated)
3. Electrification of calcination (E-Calcination)
4. Green hydrogen based calcination (H-Calcination)
5. Carbon Capture and Storage (C-Calcination)

Impacts (TJ/d)

Table 2 Summary of impacts on gas demand of different technology options for decarbonisation of alumina refining

Factor	Kwinana	Wagerup	Pinjarra[3]	Worsely	Aggregate
Curtailment	-ve 65-70[4]	-ve 75-80	-ve 75-80	-ve 120-125[5]	-ve 335-355
MVR	N/A	-ve 50 offset[6] by +ve 5-20	-ve 40 offset by +ve 5-15	-ve 80 offset by +ve 10-30	-ve 170 offset by +ve 20-65
E-Calcination	N/A	-ve 30 offset by +ve 5-20	-ve 40 offset by +ve 10-30	-ve 50 offset by +ve 10-30	-ve 120 offset by +ve 25-80
H-Calcination[7]	N/A	-ve 30	-ve 40	-ve 50	-ve 120
C-Calcination[8]	N/A	+ve 1-4	+ve 2-6	+ve 2-6	+ve 5-16

3 Pinjarra values are exclusive of gas consumed by the Alinta operated Cogen unit
4 Already being implemented
5 Assumes all Worsley boilers have previously been converted from coal to gas
6 Offsets result from the additional GPG firming required to support the incremental electricity consumption
7 Assumes hydrogen is supplied from off grid system using only renewable generation
8 Additional gas demand with CCS comes from additional GPG firming required to support incremental electricity consumption associated with operating CCS facilities

Ammonia manufacturing

Key factors

1. Curtailment (Temporary or permanent shutdown of the facility)
2. Green hydrogen feed to process
3. CCS (Assumed to be applied only to process emissions)

Impacts (TJ/d)

Table 3 Summary of impacts on gas demand of different technology options for decarbonisation of ammonia manufacturing

Factor	Ammonia facilities[9]
Curtailment	-ve 50
Green Hydrogen[10]	-ve 50
CCS[11]	Negligible

9 Both of CSBP's ammonia facilities are treated as one as they will be essentially identical and will therefore have very similar economics for decarbonisation.
10 Assumes hydrogen is supplied from off grid system using only renewable generation
11 There would be a small additional gas demand associated with CCS from the additional GPG firming required to support incremental electricity consumption associated with operating the CO2 drying, compression and injection facilities.

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Section 1 – Insights and Impacts

Analysis of key industrial shippers.

This section provides an overview of the main gas shippers and their decarbonisation commitments together with an in-depth exploration of the options they have to decarbonise and how these might affect gas consumption and demand profiles.

Alcoa

ALCOA

Introduction

Alcoa have three facilities that consume large quantities of gas delivered by the DBNGP. These are the Kwinana, Pinjarra and Wagerup alumina refineries [redacted]

Alcoa have a net zero 2050 emissions target covering Scope 1 and 2 emissions with interim targets of a 30% reduction by 2025 and a 50% reduction by 2030 from a 2015 baseline. (3)

All three refineries emit more than 100,000 tCO_2 p.a. and are therefore covered by the Safeguard Mechanism (4) which imposes an emissions limit on individual facilities with a default annual reduction of 4.9% per annum which is adjusted down for trade exposed baseline adjusted facilities which may include alumina refining subject to certain financial criteria.

The Safeguard Mechanism requires emitters that are above their baseline in any given year to purchase Australian Carbon Credit Units (ACCUs) equivalent to the difference between their emissions and the baseline and there is therefore a financial incentive for Alcoa and any other operator of a covered facility to reduce their emissions. Additionally, the Safeguard Mechanism requires emitters using ACCUs to address an emissions gap which is greater than 30% of the baseline, to provide a written explanation as to why this is the case. At a base decline rate of 4.9% p.a. with additional reductions imposed by the phasing in of default emissions intensity baselines most emitters who take no action to reduce emissions will breach the 30% threshold between the fifth and seventh year, i.e. FY28-FY30. However, as alumina manufacturing is a trade exposed industry and Alcoa are already at the lower end of the emissions spectrum, they are not expected to reach the 30% threshold this decade.

Factors

There are multiple factors that could influence Alcoa's volume and pattern of gas consumption which are explored in detail throughout this section. The primary factors are:

1. Curtailment (Temporary or permanent shutdown of a facility)
2. Electrification of steam generation
   a. Mechanical Vapour Recompression (MVR)
3. Electrification of calcination (E-Calcination)
4. Green hydrogen based calcination (H-Calcination)
5. Carbon Capture and Storage (C-Calcination)

Curtailment

Kwinana

Alcoa recently made the decision to curtail production at the Kwinana alumina refinery which was influenced by a number of factors including its age, scale, operating costs and current bauxite grades, in addition to current market conditions. (5)

This will remove up to 65 TJ/d[12] of full haul gas demand from mid-2024.

The total volume of gas demand removed may depend on whether the plant is mothballed, with a view to restarting in future, or fully decommissioned as mothballing will likely require some systems to be kept live.

Wagerup and Pinjarra

If Alcoa were to curtail Wagerup and Pinjarra refineries this would result in an additional loss of ~160 TJ/d of gas demand.

The Kwinana refinery cost of production in 2023 was US$410/tonne which was US$160/tonne higher than Wagerup and Pinjarra. (6) At ~US$250/tonne Alcoa's remaining alumina refineries are in the 1st quartile of the global cost curve and due to their gas based energy supply and efficient design they are also in the 1st quartile of global emissions intensity. (7)

In light of the above and given the positive outlook for aluminium as a key element in enabling the energy transition with demand anticipated to increase across a range of applications, curtailment of Wagerup and Pinjarra due to is considered unlikely due to operating cost pressures or commodity prices.

Another risk factor that could result in curtailment is obtaining environmental approvals for the expansion of Alcoa's bauxite mines into new areas to access fresh supplies of bauxite once the existing areas have been mined out. Failure to obtain approvals in a timely manner could result in temporary or permanent closure of the refineries.

Electrification of steam generation – a) Mechanical Vapour Recompression (MVR)

What is it?

MVR is a technology that recovers waste heat that would otherwise go to atmosphere. It achieves this by taking low temperature low pressure steam, which is currently cooled and condensed then returned to a boiler as hot condensate, and adding energy to it to turn it back into higher temperature higher pressure steam. The energy is added through a series of electric motor driven compressors which raise both the pressure and temperature of the steam as it passes through them. In doing this, all of the heat in the steam is recovered rather than being wasted and primary energy input requirements can be reduced by a factor of up to three.

MVR's long term commercial success is dependent on availability of sufficient quantities of low-cost renewable energy and higher carbon prices together with successful demonstration of the technology at scale in an alumina refinery.

For full conversion of all WA refineries the additional power demand would be ~1+ GW which equates to ~40% of the current average demand of the entire SWIS and would require the build out of ~2-3 GW of new renewables with associated storage and transmission to facilitate it.

Review of MVR feasibility study

Alcoa has completed an ARENA funded study on the technical and commercial viability of retrofitting MVR to its Western Australian refineries (8). The conclusion of this study was that MVR could replace gas for steam generation with electricity used for steam compression at a ratio of approximately 0.1 MWh of electricity per GJ of gas. Approximately 60% of the power required would be to operate the MVR compressors with the remainder replacing self generated electricity from on site steam and gas turbines which would no longer be continuously operated.
MVR is relatively capital intensive with an investment cost of ~$220 per tonne of annual alumina production capacity. This equates to a $650 million investment for a refinery such as Wagerup.

12 Gas demand has been back calculated from the values provided in the MVR Retrofit and Commercialisation Report (8) See Excel "Model input calculations" Sheet "Alcoa" for details.

The break-even electricity price for MVR with a gas price of $7.91/GJ and a carbon price of $100/tCO2-e was calculated as $90/MWh (Including capital repayment).

The sensitivities to gas price, carbon price and power price are significant, e.g., with a gas price of $10/GJ a lower carbon price of $60/tCO2 is required to maintain a $90/MWh break even electricity price.

As part of the study Alcoa estimated the total cost to develop MVR to the point of commercialisation would be in the order of $220M and take ~5 years if fast tracked. However, this fast-track commercialisation path is currently not being followed with Alcoa closing the project in April 2024 due to it being "found to be financially unviable, as it no longer met the set-out project objective of low capital form of evaporation". (9) Any continuation of the project will be heavily reliant on continued government support.

Construction of the first stage of the fast tracked trial was due to be completed at the end of 2024 and be operational in 2025. Four subsequent trials covering different areas of the plant were proposed to be completed by the end of 2031.

Given the close out of this project without significant progress, CarbonTP believe the likelihood of MVR being technically and commercially ready for at scale deployment in alumina refineries before 2035 is low. Additionally, based on a workshop with Alcoa, South32 and Rio Tinto, the Nov 2022 ARENA sponsored report, "A Roadmap for Decarbonising Australian Alumina Refining" (10) indicates two emissions abatement pathways for alumina refining. The "Gradual abatement pathway" is the least aggressive schedule and broadly aligns with a below 2C climate scenario. This shows emissions relating to digestion process heat, declining gradually from 2035 out to 2040 which supports the above position.

Impact of MVR on gas demand

Should MVR be successfully deployed at Alcoa's alumina refineries, it would remove the demand for gas to operate the boilers and gas turbines that produce steam for the bauxite digestion process but transfer a portion of that energy demand to the SWIS. For Wagerup (wg) and Pinjarra (pj) this would amount to Est. $52_{wg} + 37_{pj}$ = ~90 TJ/d requiring ~$213_{wg} + 151_{pj}$ = ~360 MW of electrical power to be imported from the grid. It is highly unlikely Alcoa will be able to source 100% of their electricity from new renewable generation with the grid still likely to be between 30% and 40% supplied by gas powered generation in 2035[13].

For context fossil fuel power generation currently accounts for 66% of electricity delivered in WA with 30% being from coal which is all planned to be retired by 2031 (11).

With a mix of both CCGT and OCGT we estimate the specific gas consumption for power generation will be 10.9 GJ/MWh[14]. Therefore, to operate the MVR at Wagerup and Pinjarra 24/7/365 we estimate an associated average rate of gas consumption for power generation of $19_{wg} + 14_{pj}$ = ~30 TJ/d. This will not however, be a steady demand but will follow the general pattern of demand for gas fired power generation as described under the section "Modelling electricity demand to forecast gas power generation – Details of Gridcog model" which addresses GPG gas demand. If all the electrical power for the MVR needed to be supplied by OCGT peakers the gas demand for power generation would be $62_{wg} + 44_{pj}$ = ~110 TJ/d.

The MVR feasibility study indicated that in the event of high power prices Alcoa would turn down their Wagerup refinery to reduce electricity demand from the SWIS by up to 131 MW which would reduce the peak gas demand for power generation to ~40 TJ/d

Beyond 2035 as the grid continues to decarbonise, we anticipate the gas demand for power firming associated with MVR will continue to decline and follow the pattern dictated by renewable generation profiles.

13 For details of SWIS power generation modelling see section "Modelling electricity demand to forecast gas power generation – Details of Gridcog model"
14 For details see Excel "Model input calculations" Sheet "SWIS generation" for details

Note on Pinjarra Cogen

Pinjarra refinery receives a lot of its steam from the Pinjarra Cogen plant co-located with the refinery. The Cogen plant is owned and operated by Alinta and is comprised of 2 x 143 MW open cycle gas turbines with waste heat recovery for steam generation on the turbine exhausts. These turbines typically operate at ~200 MW of electricity output and it is estimated they contribute ~40-50% of the steam requirement to the refinery.

Whilst there is a continuous need for thermal power generation in the SWIS which is likely to extend well beyond 2040 we anticipate these turbines will continue to operate as they are effectively the most efficient turbines in the SWIS due to their Cogen duty.

Table 4 Summary of MVR impact on gas demand for different levels of renewable penetration in the SWIS (Assumes MVR is implemented from 2035 onwards at both Pinjarra and Wagerup)

@XX% renewables penetration in electrical power supplied	Direct reduction in gas demand (TJ/d)[15]	Average incremental gas demand for power generation (TJ/d)	Minimum peak gas demand for power generation (TJ/d)[16]	Maximum peak gas demand for power generation (TJ/d)[17]
65[18]	-ve 90	+ve 33	+ve 60	+ve 110
70[19]	-	+ve 29	-	-
75	-	+ve 24	-	-
80	-	+ve 20	-	-
85	-	+ve 14	-	-
90	-	+ve 10	-	-
95	-	+ve 5	-	-

15 This is exclusive of the Cogen facility which is assumed to continue operating.
16 The minimum peak gas demand to support the supply of electricity to MVR in the event of an extended period of low renewables generation
17 The maximum peak gas demand to support the supply of electricity to MVR in the event of an extended period of low renewables generation (The difference between the minimum and maximum is the level of turn down achieved at the refinery)
18 This is the level of renewables penetration anticipated by 2030 under the SWIS modelling Scheme 1
19 This is the level of renewables penetration anticipated by 2050 under the SWIS modelling Scheme 1

Electrification of Calcination

What is it?

Calcination involves the heating of hydrated alumina to temperatures between 850-1000C to drive off the chemically bonded water resulting in a pure smelter grade calcined alumina. Currently calcination temperatures are achieved by burning gas resulting in a flue gas stream consisting mostly of nitrogen, water vapour and CO_2.

Electric calcination replaces the heat source for the calciner with an electric heat source which is used to heat up a storage and transfer medium such as molten salt, to achieve the calcination of the alumina.

Pilot trials

Alcoa is currently running a small scale electric calcination pilot (12) at their Pinjarra refinery. This is the first step on a long road to commercialisation of the technology which was assessed as TRL 4 (Early stage technology demonstration) in the ARENA sponsored Nov 2022 “A Roadmap for Decarbonising Australian Alumina Refining” (10). Similar to MVR, electric calcination will require large scale, low cost, firmed renewable power to make it commercially viable. The road map to commercial scale deployment on the “Gradual abatement pathway” indicates at scale deployment from 2040 onwards. Our perspective is that this is a realistic timeline to technical maturity.

Green hydrogen based calcination

What is it?

Hydrogen calcination replaces the gas heat source with low carbon hydrogen which may be co-fired with pure oxygen resulting a flue gas stream that is pure steam and can therefore be used elsewhere in the refinery.

Green hydrogen is made from 100% renewable electricity using electrolysers to split water into its constituent components of hydrogen and oxygen. The hydrogen is collected and purified and can then be used directly or stored for future use. Green hydrogen currently has challenged economics, especially for use as a fuel replacement for gas, and cost projections for future production at scale are speculative.

The economics of hydrogen based calcining can be improved through integration with an MVR based solution for steam generation. However, this would then require integral design and coordinated transition of both the MVR and hydrogen solutions which could delay the deployment of MVR and may not meet emissions reduction trajectory targets.

Note: *Blue hydrogen was considered as an alternative option. Blue hydrogen can be made from gas by a reforming process with the CO2 being captured and sequestered. However, there are a number of issues with blue hydrogen which we believe will make it uncompetitive with alternatives:*

1. *Thermal efficiency is approximately 75% and coupled with the energy needed to operate the CCS facilities you would need ~35-40% more gas to deliver the same amount of process heat using blue hydrogen.*
2. *Blue hydrogen does nothing to address the upstream emissions from the gas supply chain and if anything will increase them as it increases gas consumption*
3. *A Blue hydrogen plant is highly capital intensive and would require a long term take or pay contract, or to be on the balance sheet of the end user. Either way, this would be a 20+ year commitment ruling out alternative decarbonisation options during that time*
4. *It is expensive. Our estimates based on current gas prices are in the range of AU$4-6/kg which is the equivalent of gas at ~AU$30-38/GJ with breakeven carbon prices in the range of AU$450-600/t$CO_2$ based on the current gas price.*

Pilot trials

RioTinto and Sumitomo are currently constructing a hydrogen calcination pilot demonstration project at Rio Tinto's Yarwun refinery. (13) The facility is due to be on-line in 2025 with one calciner operating for 2 hours at a time on 100% hydrogen supplied from a 4 tonne storage facility which will be gradually filled from a 2.5 MW electrolyser capable of producing 250-300 tonnes of H2 per annum. (14) This will allow 60 to 70 two hour trial periods per year. Completion of the trial is scheduled for 2028 which is 2 years behind the pilot schedule assumed in the ARENA roadmap. (10) The "Gradual abatement pathway" indicates a similar schedule to electric calcination for at scale deployment of hydrogen based calcination, i.e., from 2040 onwards. The roadmap document also indicates that for commercial viability the cost of green hydrogen would need to trend below US$2/kg. Using even the most optimistic assumptions for renewable energy and electrolyser costs from the CSIRO GenCost report, our assessment is that the cost of green hydrogen is unlikely to fall to US$2/kg before 2040.

For context, on an energy equivalence basis a hydrogen price of US$2/kg is the same as a gas price of US$15/GJ = AU$23/GJ

Impact of electric/hydrogen based calcination on gas demand

Both electric and hydrogen based calcination will eliminate the requirement for gas combustion in the calciners. Currently Alcoa consume Est. $26_{wg} + 42_{pj}$ = ~70 TJ/d of gas in their Wagerup and Pinjarra refinery calciners[20]. It is assumed replacement of gas with hydrogen based calcining would completely eliminate any gas demand for calcination with the buffering of renewable electricity generation used to make the hydrogen being achieved through hydrogen storage. This assumption is based on the fact that if >22% of the electricity to manufacture the hydrogen was derived from gas it would result in more gas consumption and emissions than burning gas in the calciners for 100% of the time[21].

For electric calcination there is the option of buffering renewables intermittency with thermal storage, but also use of gas based firming of electricity. From the "Alcoa Renewable Powered Electric Calcination Pilot" (15) it is inferred that electricity required is ~0.7 MWh per tonne of alumina[22] and for gas calcination the data provided in the MVR study implies an intensity of 3.2 GJ/tonne. The ratio of electricity required is therefore ~0.22 MWh/GJ. At this ratio the electrical power required to replace the gas fired calcination is ~230wg + 380pj = 610 MW.
Even by 2040 it is considered highly unlikely the WA grid will be close to 100% renewable and our SWIS modelling indicates gas generation may still account for ~30% of electricity supplied. On this basis the average demand for gas for power generation to support electric calcining could be up to 18wg + 30pj = ~48 TJ/d with a peak demand of up to 67wg + 110pj = ~180 TJ/d.

It should be noted that due to the fact that calciners are a relatively efficient use of gas, and gas fired power generation, particularly OCGT, is a relatively inefficient use of gas for heating, even with 70% renewable electricity the amount of gas saved may only be ~30% of current consumption. Therefore, for the transition to electric calcining to make a significant difference to emissions the electricity supplied needs to come from a low emissions grid with a very high percentage of renewable generation. As such electric calcination is unlikely to be implemented as a solution unless an appropriately decarbonised and low-cost power supply is available to support it. Due to the very high power demand for electric calcining, it is also possible that operators may choose to slow down or temporarily shut down calciners in extended periods of low renewable generation.

20 For details see Excel "Model input calculations" Sheet "Alumina"
21 It requires ~55 kWh of electricity to produce and process 1 kg of hydrogen which contains 120 MJ of energy (LHV) equivalent to 133 MJ (HHV) of gas. To produce 55 kWh of electricity using an OCGT would consume ~600 MJ (HHV) of gas. Therefore, if more than 133/600 = 22% of electricity is derived from gas it will result in more emissions than just burning gas.
22 For details see Excel "Model input calculations" Sheet "Alumina

Table 5 Summary of Electric Calcination impact on gas demand for different levels of renewable penetration in the SWIS (Assumes Electric Calcination is implemented from 2040 onwards at both Pinjarra and Wagerup)

@XX% renewables penetration in electrical power supplied	Direct reduction in gas demand (TJ/d)	Average incremental gas demand for power generation (TJ/d)	Maximum peak gas demand for power generation (TJ/d)[23]
35	-ve 70	+ve 56	+ve 180
30	-	+ve 48	-
25	-	+ve 40	-
20	-	+ve 32	-
15	-	+ve 24	-
10	-	+ve 16	-
5	-	+ve 8	-

Carbon Capture Utilisation and Storage (CCUS)

What is it?

CCS – Carbon Capture and Storage, is an approach to decarbonisation which involves capturing the CO_2 emissions as they are generated and then transporting them to a suitable location where they can be injected underground into a storage formation suitable for containing them for hundreds, if not thousands of years. Typically, CCS requires the CO_2 containing gas stream to be contacted with a liquid (normally an amine based solution such Methyldiethanolamine [MDEA]) which selectively absorbs the CO_2. The liquid can then be heated to release the CO_2, which is dried, compressed, transported and injected into the storage formation.

Energy consumption for capture is typically in the order of 2.5-3.5 GJ (0.7-1.0 MWh) per tonne of CO2 (16) the majority of which is normally in the form of low temperature (~150C) steam required to regenerate the amine solution and release the CO_2. It is possible this steam could be generated with reduced additional energy input using MVR and/or high temperature heat pumps.

Note: *There are many other CO_2 capture technologies under development all at various Technology Readiness Levels. Some of these have the potential to reduce the cost and energy input requirements for capturing CO_2 but are not likely to be commercially bankable for several years.*

CCU – Carbon Capture and Utilisation, differs from CCS in what is done with the CO_2 after it has been captured. At the present the vast majority of CCU is used for enhanced oil recovery where the CO_2 is injected into late life oil reservoirs to reduce the viscosity of the oil and increase the recovery factor from the reservoir. Other applications include feeding CO_2 to greenhouses to accelerate plant growth although the impact of this is debateable as it is essentially an acceleration of CO_2 uptake by the plants rather than an increment, and the CO_2 is quickly returned to the atmosphere when the plants die and the food is eaten.

There is also a lot of discussion regarding using captured CO_2 to synthesise chemical precursors and e-fuels such as green methanol, e-Jet through the chemical reaction of CO_2 with green hydrogen, essentially reversing combustion. (17) Whilst technological solutions exist to do this, such as combining the reverse water gas shift reaction ($CO_2 + H_2 \rightarrow CO + H_2O$) with the Fischer-Tropsch synthesis reaction ($CO + 2H_2 \rightarrow [1/n][CnH_{2n}]$); these solutions are a long way from bulk commercial viability with challenges in the cost of green hydrogen and selectivity of the process, i.e., Only a fraction of the molecules produced will be the target molecules, mixed with a range of other molecules which need to be separated and further processed or recycled.

23 The maximum peak gas demand to support the supply of electricity to calcining in the event of an extended period of low renewables generation. In reality it is anticipated calciners would be turned down to load shed but currently the degree of turn down achievable is unknown.

Additionally, the processes are currently highly inefficient requiring substantially more energy input than the energy content of the fuel obtained which in turn will only deliver a fraction of its embodied energy in useful work when combusted in an engine or turbine. Indications are that e-fuels are currently substantially more expensive than their fossil fuel counterparts and will remain so without large penalties for emissions over and above anticipated carbon prices. (18)

Pilot trials / technology evaluation

There is no publicly available data to suggest any Australian alumina refineries are trialling CCS in alumina refining and there have been no pilot trials anywhere that we are aware of for CCS applied to alumina calciners. However, there is some evidence that a group of companies are looking to develop CCS in relation to aluminium although this may not be specific to calcining. (19) CCS is an option that would support continued use of gas.

From our experience in evaluating CCS projects there is a minimum volume of CO_2 that is required to reduce the unit costs and make the Storage part of the project commercially competitive with alternative decarbonisation solutions. For an onshore Storage reservoir such as a saline aquifer or depleted gas reservoir we estimate this volume is around one million tonnes per annum, which is more than the calcining emissions of any individual alumina refinery in WA. Therefore, for CCS to be a viable solution we believe there would need to be a collaboration between the refineries in the region to pool their CO_2 for injection in a single common reservoir. This pooling arrangement could also include the CSBP ammonia plant(s) which have a concentrated source of CO_2 pre-captured and available for Storage.

Cost structure and implications

A CO_2 Storage facility is highly capital intensive and the investment would need to be underpinned by the equivalent of long term “take or pay” contracts covering CO_2 disposal over a period of ~20 years. This would therefore lock in this solution for the duration of the contract and effectively prevent the implementation of any alternative solution, even if the economics of the alternative were more attractive.

Capture and Storage costs are in the region of AU$120-180/t$CO_2$ with approximately 70% of the cost being in the capture if the CO_2 is not a pre-captured stream as part of the process such as in ammonia manufacturing. (20)

Impact of CCUS on gas demand

Application of CCS would result in continued consumption of gas for calcining with some small quantity of incremental gas required for firming the power used to operate the CCS facilities which would depend on the penetration renewables in the grid.

The average daily emissions associated with gas fired calcining are ~1,300wg and 2,200pj. Assuming a total energy requirement of ~3 GJ (0.83 MWh) per tonne of CO2 captured and sequestered and 30% gas firming of the grid the additional gas consumption associated with operating the CCS facilities for both refineries would be ~10 TJ/d. With the implementation of MVR to make use of the waste heat from the calciners we anticipate energy consumption would likely be much lower than this and therefore incremental demand for gas fired firming resulting from CCS would essentially be negligible in the context of total gas demand.

South32

Introduction

South32 have operate Worsley Alumina refinery which contracts large quantities of gas delivered by the DBNGP. The refinery currently consumes [redacted] and is in the process of converting coal fired boilers used for steam raising to gas fired boilers. (21) So far one of five boilers has been converted with 4 remaining. Each additional boiler is estimated to [redacted]

South32 have a net zero 2050 emissions target covering Scope 1 and 2 emissions with an interim target of a 50% reduction by 2035 from an FY21 baseline. (22)

The refinery is covered by the Safeguard Mechanism.

South32 will have a high initial baseline due to their historical emissions profile operating coal fired boilers. Switching these boilers from coal to gas will save ~208,000 tCO_2 per annum, or ~5.5% of Worsley's historical emissions (21). Therefore, converting one boiler per year should keep South32 ahead of their adjusted baseline out to ~2030.

Factors

South32 have the same factors as Alcoa as they operate a very similar facility.

Curtailment

Assuming all boilers are converted to gas, future curtailment of production at Worsley would reduce gas demand by ~125 TJ/d.

With FY23 operating costs of US$291/tonne (22), a current alumina price of ~US$500/tonne (23) and a very positive outlook for aluminium and alumina demand, curtailment of Worsley due to higher gas prices is considered an unlikely outcome.

With future gas consumption, after conversion, of ~11 GJ/tonne, an increase in the domestic gas price of AU$10/GJ coupled with a carbon price of AU$100/$tCO_2$ would add ~US$110/tonne to operating costs which would still leave Worsley with a positive operating margin.

South32 are also exposed to the same mine expansion approval.

Electrification of steam generation – Mechanical Vapour Recompression (MVR)

It is assumed South32 have explored MVR and established their own estimates of the power requirements and cost of conversion. However, these data are not publicly available and therefore the Alcoa study data is being used for this assessment.

Impact of Implementation of MVR on gas demand

Should MVR be successfully deployed at Worsley it would remove the demand for ~80 TJ/d of gas assuming all boilers are converted to gas prior to this point.

This would require ~320 MW of electrical power to be imported from the grid.baseline out to ~2030.

Using the same calculation basis as the Alcoa refineries, to operate MVR at Worsley 24/7/365 we estimate an associated average gas consumption for firming power generation of ~30 TJ/d following the general pattern of demand for gas fired power generation. If all the electrical power for the MVR needed to be supplied by OCGT peakers the gas demand for power generation would be ~90 TJ/d.

Assuming Worsley would be able to turn down to a similar extent as Alcoa the peak gas demand for power generation could be reduced to ~30 TJ/d

Table 6 Summary of MVR impact on gas demand for different levels of renewable penetration in the SWIS (Assumes MVR is implemented from 2035 onwards at Worsely Alumina)

@XX% renewables penetration in electrical power supplied	Direct reduction in gas demand (TJ/d)	Average incremental gas demand for power generation (TJ/d)	Minimum peak gas demand for power generation (TJ/d)[34]	Maximum peak gas demand for power generation (TJ/d)[35]
35	-ve 80	+ve 29	+ve 50	+ve 90
30	-	+ve 25	-	-
25	-	+ve 21	-	-
20	-	+ve 17	-	-
15	-	+ve 13	-	-
10	-	+ve 8	-	-
5	-	+ve 4	-	-

Electric / Hydrogen based Calcination

South32 have exactly the same technology options and use cases as the Alcoa alumina refineries

Impact of electric/hydrogen based calcination on gas demand

Both electric and hydrogen based calcination will eliminate the requirement for gas combustion in the calciners. Currently South32 consume [redacted] in their Worsley refinery calciners26. It is assumed replacement of gas with hydrogen based calcining would eliminate any gas demand to support calcination.

From the "Alcoa Renewable Powered Electric Calcination Pilot" (15) it is inferred that electricity required is ~0.7 MWh per tonne of alumina[27] and for gas calcination the data available from South32 implies an intensity of 3.7 GJ/tonne. The ratio of electricity required is therefore ~0.19 MWh/GJ. At this ratio the electrical power required to replace the gas fired calcination at Worsley is ~360 MW.

The average demand for gas for power generation to support electric calcining could be up to ~30 TJ/d with a peak demand of up to ~100 TJ/d

24 The minimum peak gas demand to support the supply of electricity to MVR in the event of an extended period of low renewables generation
25 The maximum peak gas demand to support the supply of electricity to MVR in the event of an extended period of low renewables generation (The difference between the minimum and maximum is the level of turn down achieved at the refinery)
26 For details see Excel "Model input calculations" Sheet "South32"
27 For details see Excel "Model input calculations" Sheet "Alumina"

CARBON TP

Table 7 Summary of Calcination impact on gas demand for different levels of renewable penetration in the SWIS (Assumes Calcination is implemented from 2040 onwards at Worsely Alumina)

@XX% renewables penetration in electrical power supplied	Direct reduction in gas demand (TJ/d)	Average incremental gas demand for power generation (TJ/d)	Maximum peak gas demand for power generation (TJ/d)[28]
35	-ve 70	+ve 56	+ve 180
30	-	+ve 48	-
25	-	+ve 40	-
20	-	+ve 32	-
15	-	+ve 24	-
10	-	+ve 16	-
5	-	+ve 8	-

Carbon capture Utilisation and Storage (CCS)

See previous section for Alcoa.

28 The maximum peak gas demand to support the supply of electricity to calcining in the event of an extended period of low renewables generation. In reality it is anticipated calciners would be turned down to load shed but currently the degree of turn down achievable is unknown.

Wesfarmers

Introduction

CSBP operate a 260,000 tpa ammonia plant in Kwinana which consumes [redacted]

The CO_2 generated in the reforming process is captured and removed from the gas stream to leave a blend of nitrogen and hydrogen ready for ammonia synthesis. This concentrated stream of CO_2 is currently vented to atmosphere and amounts to ~300,000 tpa.

CSBP have also announced EPA support for an expansion of ammonia production by 300,000 tpa to replace imported ammonia and taking the total production to ~560,000 tpa which would increase demand for gas by ~27 TJ/d and generate an additional ~540,000 tCO2 per annum according to their greenhouse gas management plant (24).

With regard to the new facility, CSBP have set Scope 1 emissions reduction targets of 30% by 2030, 40% by 2035, 70% by 2040, 80% by 2045 and 100% by 2050.

Factors

There are only 3 main factors that could influence CSBP volume and pattern of gas consumption for ammonia production and these are:

1. Curtailment (Temporary or permanent shutdown of a facility)
2. Green hydrogen – To directly replace hydrogen made from gas
3. Carbon Capture and Utilisation / Storage (CCUS)
4. In their Greenhouse gas Management Plan, CSBP identified CCS, CCU and green hydrogen as the mitigation methods they were pursuing to meet their emissions reduction targets.

Curtailment

This would seem to be an unlikely outcome although deferral or cancellation of the proposed new facility is considered a realistic prospect if domestic gas prices continue to rise. If CSBP continued to operate their existing facility on gas and CCS does not prove a viable solution, in a rising domestic gas price environment coupled with high carbon prices, there is a chance it could be more commercially attractive to curtail local production and import all their ammonia, as they do now for ~50% of their requirements. Cancellation of the new facility coupled with curtailment of the existing facility would reduce forecast gas demand by ~50 TJ/d.

Green Hydrogen

CSBP through WesCEF (Wesfarmers Chemicals, Energy and Fertilisers) indicated they were participating in a feasibility study with APA group in 2023, to explore the possibility of using green hydrogen produced remotely and piped to their facility using the Parmelia gas pipeline, repurposed for hydrogen. (25)

The estimated cost of grey hydrogen at a gas price of AU$10/GJ is ~$3.50-4.00/kg. We estimate the current cost of a buffered supply of green hydrogen suitable to feed a continuous process such as an ammonia plant to be in the region of AU$7-9/kg. The recently announced AU$2/kg subsidy for green hydrogen therefore covers <50% of the gap. To close the gap completely would require a carbon price of >AU$200/tonne together with the AU$2/kg subsidy.

The costs of producing green hydrogen will reduce over time and assuming the renewables and electrolyser capital costs provided in the CSIRO GenCost data (26) we estimate that green hydrogen could become commercially viable for ammonia production by 2040, although this would depend on:

1. Gas price
2. Carbon price
3. Government subsidies and
4. Premiums for low emissions ammonia

If green hydrogen did become commercially viable it would eliminate the need for both process gas and fuel gas for ammonia synthesis. Applied to both the existing and new CSBP facilities green hydrogen would reduce gas demand by ~50 TJ/d

Note on green hydrogen costs: *The CSIRO GenCost report indicates the cost of an electrolyser in 2024 is AU$2,577/kW (PEM) and AU$1575/kW (Alk). We assume these represent fully installed all in costs including balance of plant, land, insurance etc. CSIRO indicate an expected 80% reduction in costs to AU$229-377/kW due to scaling of electrolysers from 10MW to 100MW over the period to 2050. We believe these reductions are optimistic given the cost breakdown structure of electrolyser installations reported by European projects. (27). The average reported cost was ~€3050/kW (~AU$4,900/kW) with the electrolyser only accounting for 30% of the total installed cost. This implies a transition to green hydrogen is likely to remain commercially challenging without heavy subsidies and high carbon prices.*

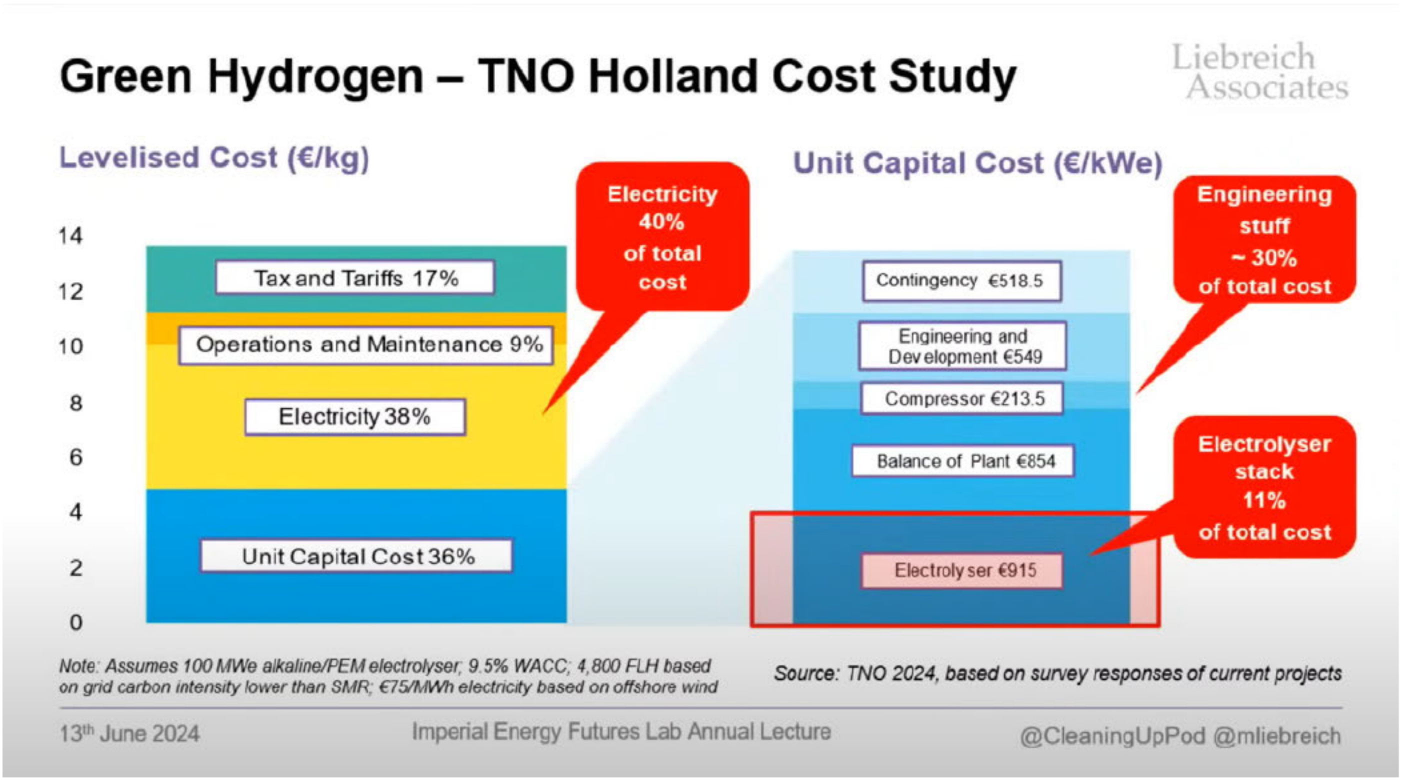


Figure 2 Hydrogen electrolyser project costs from the EU.

CCUS

An alternative, decarbonisation solution for CSBP is CCUS, which would facilitate continued use of gas whilst simultaneously reducing emissions. Due to the nature of the ammonia manufacturing process CSBP have a pre-captured concentrated stream of ~300,000 tCO_2 p.a. available for Use or Storage which accounts for ~60-70% of their current emissions. The proposed new facility is of almost identical design to their existing facility and would add ~370,000 tpa of pre-captured emissions. Aggregating these two streams should make Storage more commercially viable as scale is critical for reducing unit costs.

However, it is CarbonTP's view that even with the aggregated process emissions of both the existing plant and the new plant, CSBP would need to collaborate with other emitters, e.g., alumina calcining, to reach a commercially viable quantity of CO_2 for Storage.

A CO_2 Storage facility is capital intensive to develop and hence requires long term (20+ years) "sequester or pay" contracts to underpin the initial investment. Therefore, If CSBP were successful in implementing a CO_2 Storage contract it is likely it would be for a minimum of 20 years or more and this would lock them into that solution for the period of the contract, effectively excluding green hydrogen and guaranteeing continued gas consumption. However CCUS would only address 65-70% of CSBP's emissions which would meet their emissions reduction targets up to 2045 at which point they would need to either electrify their reforming furnaces, operate them on green hydrogen, or extend the CCS solution to the reformer flue gases.

We believe there is a high likelihood that CSBP will continue to be a significant gas shipper in the medium term with potential to continue to ship gas out to 2050 and beyond.

Potential new shippers

Potential new shippers include industries where gas is seen as an emissions reduction option, e.g., in DRI steel making where gas takes the place of coal as the reducing agent for the iron ore. The impact of using gas is to reduce the overall emissions from the steelmaking process by up to 60%. The gas may then be progressively replaced with green hydrogen if this becomes more commercially viable.

There is a possibility that construction of a DRI plant in the mid-West in the post 2030 time frame could increase domestic gas demand by up to ~75 TJ/d. The origin of the gas and location of the plant would determine whether this had any significant shipping / revenue implications for the DBP.

Other new sources of demand will depend on the deployment of sufficient low cost and high capacity factor renewable generation to attract energy intensive industries wishing to decarbonise, such as aluminium smelting. The gas demand would stem from the large scale firming required to bridge the gaps in renewable generation. For an aluminium smelter consuming 1 GW of electricity, providing only 10% of annual consumption from an OCGT peaker would require ~9,000 TJ p.a. equivalent to an average demand of ~25 TJ/d with an estimated peak demand of ~200 TJ/d

Section 2 - Approach to Modelling

The High-Level Approach

This section describes the approach that CarbonTP took to model the potential range of future gas demand through the DBNGP and the rationale for how the modelling was performed. Subsequent modelling of how this may impact the tariff was performed by AGIG and is described in separate documents which are referenced within this section.

High-level approach to modelling

1. Identify current and potential future shippers generating the majority of AGIG's revenue, i.e., those requiring large quantities of gas on a full haul basis, and/or needing to reserve significant full haul capacity.
2. For material current and potential future shippers, identify direct influencing factors, technologies and decisions likely to impact their gas consumption and contracting strategy over time, e.g., deployment of Mechanical Vapour Recompression is a key factor in future decarbonisation of alumina refining.
3. For each direct influence, identify the main input variables and other key conditions which will contribute to whether that influence should be active in the model, e.g., gas price is a key variable that will influence the commercial viability of every technology targeted at replacing gas with something else.
4. For each of the relevant input variables identify the contextual factors likely to have a material influence on them and how these factors could affect the input variables over time, e.g., Revision of the Domgas reservation policy will affect domestic gas supply and prices.
5. Develop discrete input variable profiles consistent with an understanding of the possible contextual factor outcomes and other relevant influencing factors, e.g., Domgas reservation policy failure results in pressure on domestic gas supply and so a gas price profile with higher prices would logically reflect this.
6. Construct cases representing a range of contextual factor outcomes with their corresponding input variable profiles, e.g., In the Domgas policy failure case, sustained higher gas prices would make higher percentages of renewables with storage in the grid commercially competitive with gas firming and also improve the economics of electrification potentially accelerating the transition of industry away from gas whilst at the same time reducing the amount of gas firming required in the grid. (See section "Scheme construction" for further details).
7. Use the developed cases as the basis for forecasting the range of gas demand for power generation and corresponding power generation mix over the period to 2050 using the Gridcog modelling software with each case corresponding to a scheme in Gridcog.
8. Use the developed cases combined with corresponding Gridcog scheme outputs as input data for electricity cost calculations.
9. Use gas forecast gas demand for power generation, electricity calculation model and corresponding input variable profiles, with a superimposed level of random variability, as inputs to the AGIG demand model to determine a range of potential industrial outcomes and future DBNGP gas throughput patterns.

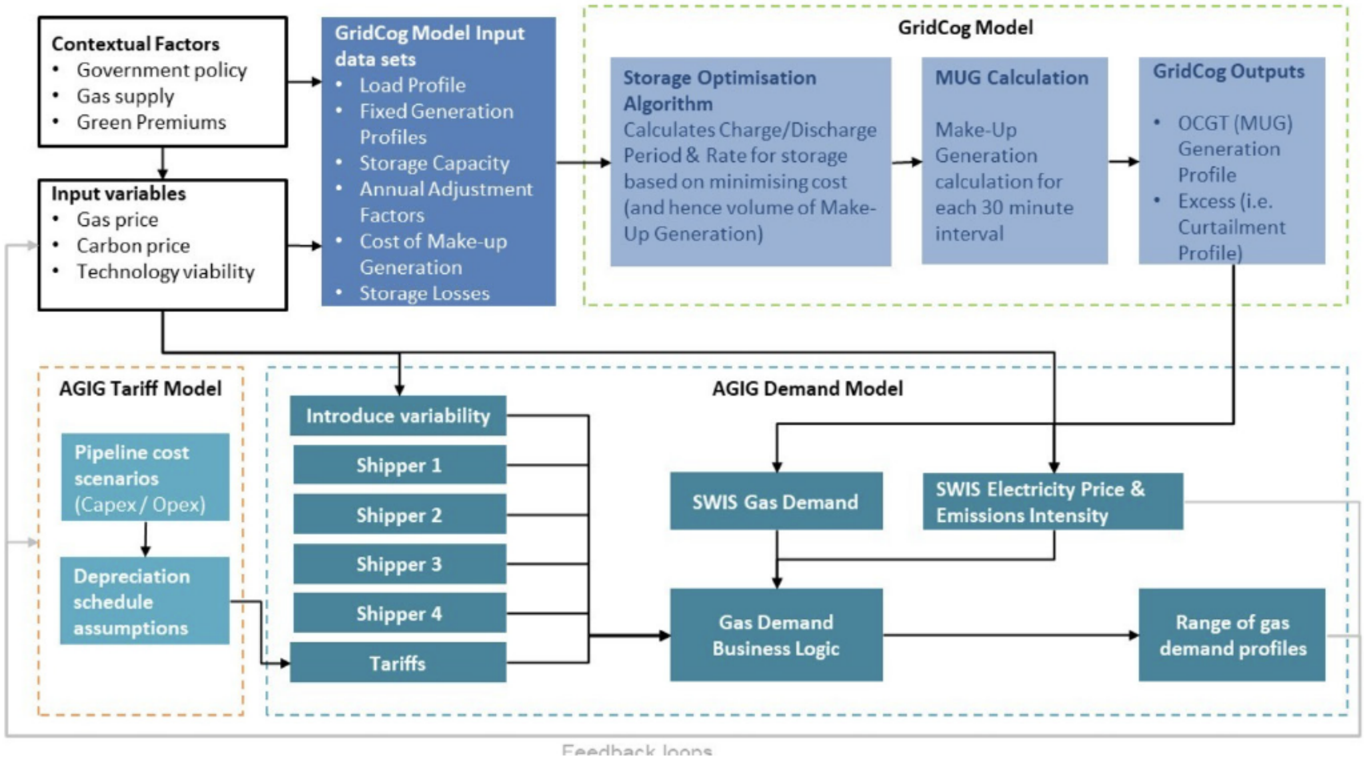


Figure 3: Functional Block Diagram of integrated model

Modelling objectives and high-level functionality

The objectives of the modelling were to understand a possible future range of gas consumption and usage patterns for both the industrial and power generation sectors how this might impact the utilisation of the DBNGP and future contracting strategies and tariffs.

To simplify the modelling the future was broken up into five year time steps corresponding to the tariff review periods. The approach developed to perform the analysis consists of three models as depicted in Figure 3. The functionality, development and population of these models is addressed in the following sections.

1. **Gridcog model (Within green dashed line)** – A simplified SWIS network model, based on Gridcog software, that forecasts gas powered generation (GPG) required to balance total grid demand in thirty minute intervals. GPG demand is converted to peak and average gas demand as an input to the AGIG demand model. The Gridcog model also outputs the generation mix for each time step which is used to calculate an average electricity price as . See section on "Electricity price calculations" for further details. Full details of the Gridcog modelling are provided in the section "Modelling electricity demand to forecast gas power generation – Details of Gridcog model "
2. **AGIG Demand Model (Within blue dashed line)** – an Excel model with economic decision logic based on, technology maturity, gas price, carbon price, and electricity price, to determine whether the major shippers' gas demand might change during any given period, either through electrification or curtailment. Full details of the AGIG demand model can be found in the separate document entitled, Attachment 6.3.DBP: Long Run Demand Model.
3. **AGIG Tariff Model (Within Orange dashed line)** – an Excel model that calculates pipeline tariff values for each time step as an input to the AGIG Demand Model and uses the outputs from the AGIG demand model to calculate the tariff for the subsequent time step. Full details of the AGIG Tariff Model can be

Treatment of feedback loops

It was recognised that there are feedback loops between the different factors within the models, e.g., changes in consumption of gas and electricity will impact the supply demand balance of both those energy sources which in turn, will impact their price.

However, it was concluded that a fully dynamic model incorporating all interacting variables and feedback loops would have been impossibly complex and of limited additional value, as eventually all input variables translate into a handful of relevant costs which ultimately will determine the commercial decisions affecting industrial gas demand.

Therefore, reliably modelling a number of defined “What if” cases, with a range of different cost input assumptions, provides as much insight into potential outcomes as trying to model the feedback loops. Additionally, the influence of any feedback loops will have a significant delay and would not be apparent in the short term, e.g., a rapid increase/decrease in gas price and/or carbon price would not change the outcome of the electricity dispatch model as GPG will always be dispatched after renewables and storage due to renewables/storage effectively having zero marginal cost. To increase available renewable generation, storage and transmission infrastructure in response to high gas prices would be a multi year effort.

Instead, the potential impact of feedback loops is inherently included in the different cases developed. For example: The accelerated case is consistent with high gas and/or carbon prices incentivising faster deployment of renewable generation.

Section 2 – Approach To Modelling

Modelling Process - Stages of development

1. Shipper identification

Identify current shippers generating the majority of AGIG's revenue, i.e., those requiring large quantities of gas on a full haul basis, and/or needing to reserve significant full haul capacity.

In running through this exercise, it became apparent that only a very small number of existing industrial shippers will be material to changing AGIG's revenue over the next 25+ years. These facilities were the alumina refineries and CSBP's ammonia plant and therefore only these were modelled in detail together with the demand for gas power generation.

Table 8 Shippers identified as material to AGIG's revenue

Shipper	Full haul throughput TJ/d	Full haul capacity TJ/d	Part haul throughput TJ/d	Part haul capacity TJ/d	Approximate percentage of revenue
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

29 Includes, gas to ammonia, gas for power generation and domestic gas

30 South32 use will increase up to a maximum of ~120 TJ/d if all boilers are converted from coal to gas

2, 3 & 4 Identify influencing factors, input variables contextual factors and inter-relationships between them

Details of this process and a diagram illustrating the factors considered and their inter-relationships can be found in *Appendix 1.*

5. Develop input variable profiles

Develop discrete input variable profiles consistent with an understanding of the possible contextual factor outcomes and other relevant influencing factors, e.g., Domgas reservation policy failure results in pressure on domestic gas supply and so a gas price profile with higher prices would logically reflect this.

GAS

Gas supply perspective

A perspective on gas supply is required as an input to the gas pricing scenarios developed for use in the modelling. The Australian Energy Market Operator (AEMO) produces an annual gas market overview, the WA Gas Statement of Opportunities [GSOO]. AEMO's 2023 WA GSOO identified a tight supply-demand balance for WA's domestic gas market.

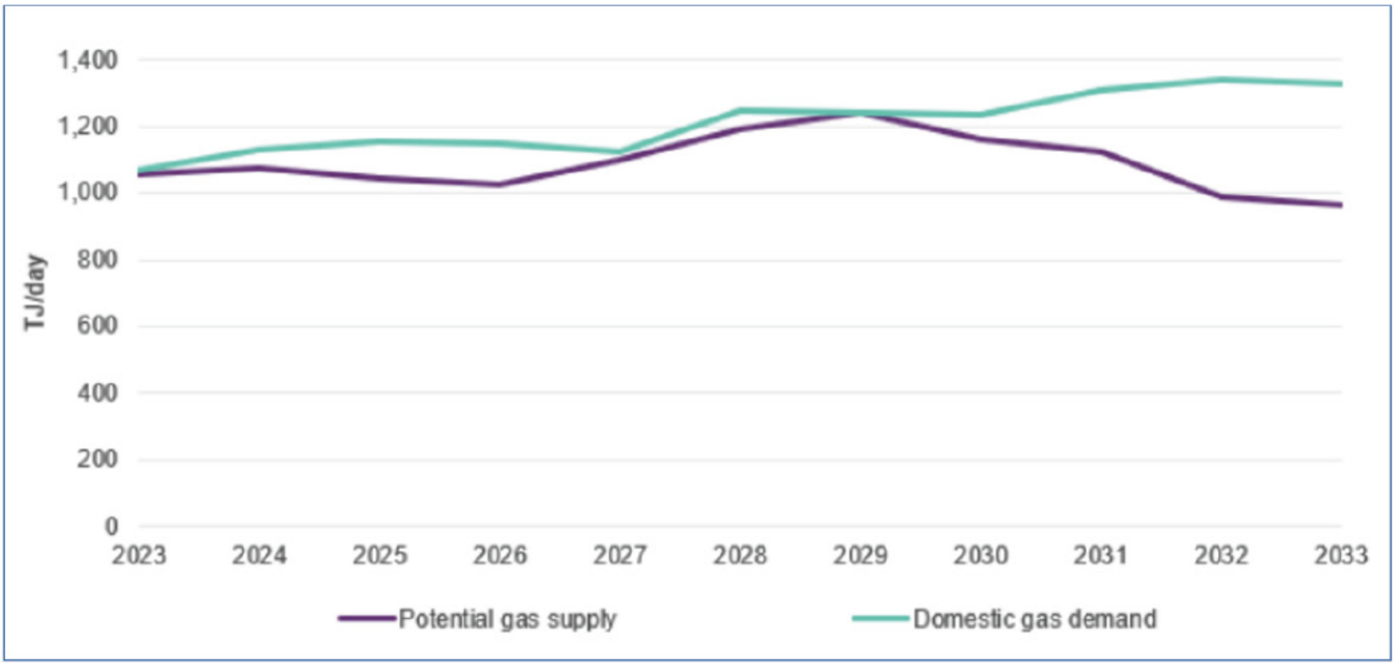


Figure 4: Expected scenario supply-demand balance, 2023 to 2033

The WA domestic gas market is projected to be in deficit between 2024 and 2029, with potential supply from committed and expected projects up to 11% below forecast demand. Recent appraisal well results and reserves write-downs in the North Perth Basin have put further pressure on gas supply forecasts.

Gas supply has been negatively impacted in recent years due to declining reserves feeding Woodside's Karratha Gas Plant, curtailed production at Santos' facilities at Devil Creek and Varanus Island, reserves write-downs in the North Perth Basin, and declining gas exploration and development activity in WA.

However, WA does not have a gas shortage since approximately 90% of all gas produced in the state is exported as LNG, but while LNG netback prices continue to exceed domestic gas prices, gas producers have a financial incentive to export gas rather than offer it into the domestic gas market.

The primary contextual factor driving the domestic gas price in WA is the State Government's Domestic Gas Reservation policy. The policy was first formalised in 2006 and further clarified in 2012, 2020, 2023 and 2024.

The policy seeks to make gas equivalent to 15% of exports available for WA consumers. LNG exporters' domestic gas commitments complement supply from domestic-only projects using the WA gas pipeline network. Gas in the WA pipeline network is not for export with the exception of 20% of volumes produced from new projects and expansions between now and end 2030. (28)

If a revised Gas Reservation Policy is wholly successful in retaining sufficient volumes from LNG exporter reserves to avoid a shortfall in domestic gas supply, it is reasonable to expect that domestic gas prices will be closely aligned to the underlying cost of local onshore domestic gas production.

Prior to 2020, WA domestic gas prices were relatively stable for decades, with prices reflecting the cost of gas production, gas demand and availability of gas for the domestic market. Historically WA domestic gas prices have been relatively stable even whilst there have been large fluctuations in international gas prices.

However, spot prices have generally trended upwards over the past three years, rising from A$2.13 /GJ in May 2020 to A$9.64 /GJ in September 2023. Meanwhile, AEMO estimates that the cost of production of WA domestic gas will remain unchanged at near A$3.0 /GJ over the next 10 years.

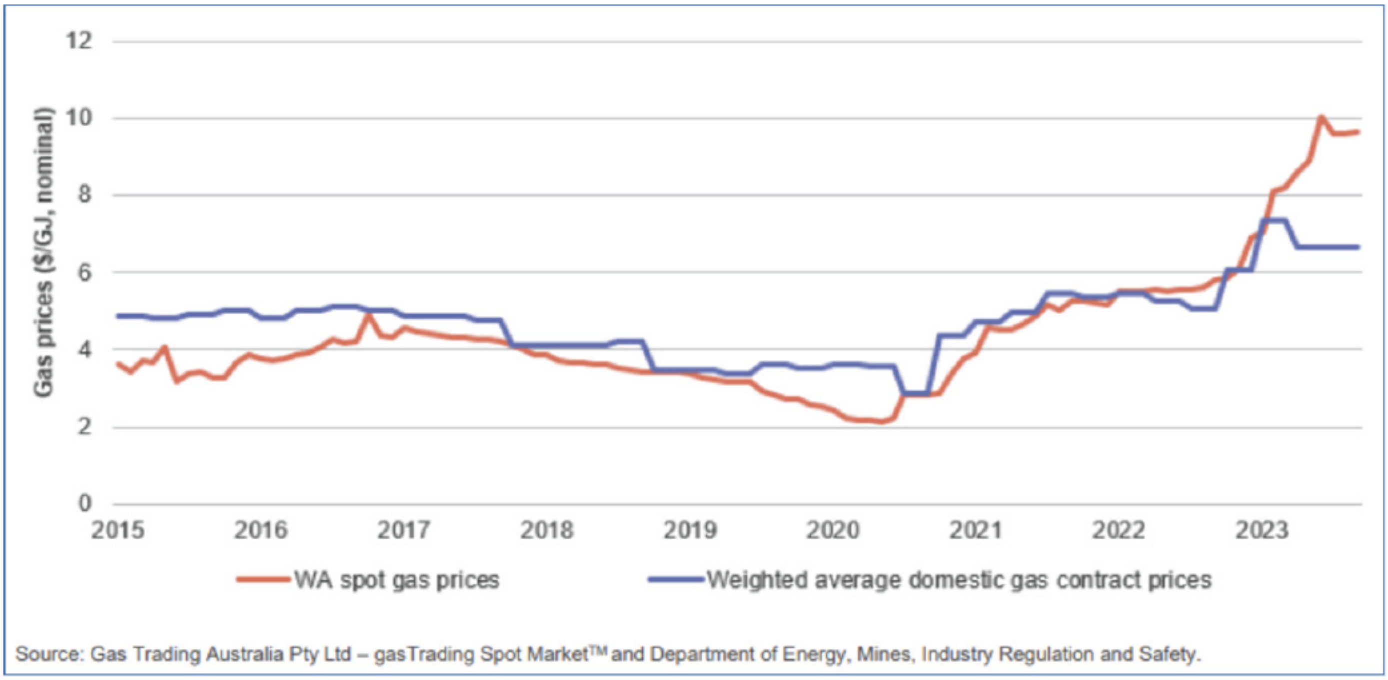


Figure 5: Historical WA domestic gas prices

Since late 2022, domestic gas prices have become disconnected from the cost of production and are trending towards parity with international LNG prices, suggesting that the Gas Reservation Policy is no longer successfully managing the domestic gas supply / demand balance. A recent review of the Domgas Reservation policy has found that, "Gas market reforms will allow Western Australians to secure access to sufficient supplies of gas, on reasonable terms, and at prices which preserve the State's competitive advantage as a gas-rich jurisdiction." (29)

Gas pricing scenarios

This sub-section describes the gas pricing scenarios developed for the modelling and the rationale for their selection.

The primary contextual factor driving gas price is the Domestic Gas Reservation policy. There are three distinct potential outcomes identified for this policy:

1. **Success** - It is wholly successful in retaining sufficient volumes from LNG exporter reserves to avoid a shortfall in domestic gas supply.
2. **Partial success** - It is partially successful retaining sufficient exporter reserves to avoid fully tying domestic gas pricing to LNG export prices
3. **Failure** - It is wholly unsuccessful resulting in domestic gas prices rising to LNG netback parity

Success

Under a success case outcome, the state government makes a strong intervention and effectively ties domestic gas prices closely to the underlying cost of local onshore domestic gas production. From 2025 to 2035 gas pricing follows the EnergyQuest "Low" forecast from the West Coast Gas Outlook – November 2023 report (30). [redacted]

[redacted] with some near term decline in GPG demand due to the impact of new renewable capacity and later increases in GPG, due to the closure of coal fired power generation (CPG), being deferred by 3 years. We see deferral of CPG closures as a highly unlikely in this case as there would be no driver to defer coal closures in a lower gas demand low price environment. The only significant increase in demand is due to the Perdamen Urea project, which will have negligible impact on DBNGP throughput, and this is partially offset due to reduction in demand from the mining sector as more renewable capacity is deployed at mine sites.

We have assumed the impact of declining onshore supply with potentially increasing production costs post 2035 is moderated by more domestic gas being supplied from the LNG exporters, driven by sustained strong government policy, and in the later years demand is assumed to be curtailed by shippers progressively electrifying as renewables and storage costs continue to decline, maintaining a relatively stable price.

***Note**: It is recognised that there are feedback loops and lower prices may result in increased demand, or existing demand persisting for longer which may then drive prices higher. These eventualities are explored in the alternative pricing scenarios.*

Partial success

In a partial success case, the state government's intervention in domestic gas policy prevents domestic gas prices being tied directly to LNG netback pricing in the short term but there is tension in the system between supply and demand rather than the historical situation of plentiful supply. From 2025 to 2035 prices broadly follow the EnergyQuest "Base" forecast. (30). [redacted]

A recent article from WoodMac (31) indicates Global LNG demand has potential to remain strong even as the world decarbonises and overall global gas consumption reduces. This is driven by economic growth in Asia coupled with coal to gas switching. Under these circumstances global LNG prices are unlikely to decrease. [redacted]

- [redacted]

[redacted]

Failure

In the failure case the government is completely ineffective in reserving LNG volumes for domestic use. With a dependence on the LNG projects to make up volumes to meet domestic demand this effectively ties Domgas prices to LNG netback pricing. With LNG projects such as the NWS coming off plateau, the only way to secure sufficient domestic supply is to pay enough to make it worthwhile for the LNG producers to divert capacity to the domestic market.

From 2025 to 2035 prices follow the EnergyQuest high case which is based on LNG netback pricing.

We assume global gas and LNG demand remain high as the world struggles to decarbonise high temperature heat, with flue gas CCUS or blue hydrogen proving to be the lowest cost solutions in many applications, allowing continued use of gas whilst meeting decarbonisation targets.

In their "High" case, EnergyQuest forecast an increase in domestic demand from 1,100 TJ/d to 1,600 TJ/d. This effectively has the same impact as failing to reserve sufficient capacity for the domestic market, tying domestic gas pricing to LNG netback pricing. The key drivers of the increase above the base case are three distinct projects:

- [redacted]

Considering whether the above increase in demand is likely, our perspective is that H2Perth and Project Haber have a low probability of driving any increase in gas demand pre-2030 given the most recent publicly available information and lead times on development. (33) (34). These projects can be reassessed in five years for the AA7 review period. From 2035-2050 we have assumed the Domgas price is equivalent to the [redacted] but driven by sustained gas exports rather than increased domestic demand.

Table 9 Domestic gas price profiles - Prices are given in 2024 AUD Real.

Domgas policy outcome	2025-30	2030-35	2035-40	2040-45	2045-50	2050-55	2055-60	2060-65
Success	5	5	5	5	5	5	5	5
Partial	9	10	12	12	12	12	12	12
Failure	13	13	17	17	17	17	17	17

CO2 Emissions

Carbon pricing scenarios

This section describes the carbon pricing scenarios used in the modelling and the rational for their selection.

CarbonTP reviewed a number of carbon price forecasts to understand the potential range of carbon prices which could impact the economics of decarbonisation within Western Australia. Clearly Australian Carbon Credit Unit (ACCU) prices will be the primary driver of the cost of carbon to large emitters covered by the Safeguard Mechanism, however emitters with exposure to export markets may find their products are exposed to higher carbon prices at the destination location under a carbon border adjustment mechanism.

For example: The EU has established the Carbon Border Adjustment Mechanism , CBAM (35) which will come into full effect from 1 Jan 2026. Companies wishing to import goods covered by the mechanism, which include aluminium and fertilisers, made respectively from alumina and ammonia, will need to pay a carbon tax rate equivalent to the price defined at the time of import by the EU emissions trading scheme (ETS). Whilst the embedded emissions from alumina production are currently not within scope for aluminium (36) the emissions for ammonia production are covered (37) and it is a reasonable expectation the boundaries of the CBAM will be expanded over time.

The EU ETS price at time of writing is ~€70/tCO2-e but has been as high as ~€105/tCO2-e (38) this is equivalent to a range of ~AU$110-170/tCO2-e.

It is possible that application of CBAM style taxes to imported goods will result in equivalent taxes at the point of origin to retain the money in the local economy. Therefore, future carbon prices may be significantly higher than they are now and for certain products the relevant prices may be substantially higher than the local carbon market prices.

Base Carbon Price Scenario

For the base carbon price scenario, we have assumed the values from the Reputex Energy Report on ACCU pricing compiled for the Climate Change Authority in August 2023 (39). The case we have used is the "High Emissions Case" which is characterised by the assumption that covered emitters will not be pro-active in reducing emissions which will drive a higher demand for ACCUs and hence a higher price, with the price of ACCUs driving decarbonisation decisions rather than vice versa.

This approach is consistent with the modelling basis whereby emitters are considered to make rational economic decisions driven by gas, electricity and carbon prices together with the investment cost for the technology required to reduce emissions.

The Reputex forecast does not extend beyond 2035, so for values from 2035-2050 we have assumed an annual increment equivalent to the average compound annual growth rate up to 2035 using the Moderate Emissions Scenario 2024 price of AU$48 as the base for the calculation. This results in a CAGR of 5.4% and a 2050 ACCU price of AU$198.

It is noted that a real 2050 ACCU price of AU$198 is above the implied government cost containment reserve price of AU$75 for the 2023/24 year, increased in real terms at 2% annually (40) equating to a 2049/50 price of ~AU$126. However, the volume of ACCUs in the reserve is finite and the price point at which facilities can access ACCUs from the cost containment measure is proposed to be reviewed, alongside other Safeguard Mechanism details, in the 2026-27 financial year.
For context, the spot market ACCU price at the time of writing was ~AU$34 (41).

Higher Carbon Price Scenario

For a higher carbon price scenario, we have taken the Australian Energy Regulator (AER) guidance on valuing emissions reductions in regulatory processes (42). These values serve as guidance to regulated network owners, both gas and electricity, on what value they should put on carbon emissions reductions in their economic evaluation of future investments. These values do not currently apply to WA regulated infrastructure, nor do they apply to unregulated assets. However, they provide a rational alternate perspective on the value of carbon emissions reduction which could be applied to any project economics.

Very High Carbon Price Scenario

The very high price scenario is predicated upon the assumption that the more severe impacts of climate change start to be felt much more severely and much earlier than anticipated prompting governments to act, raising carbon prices to the levels necessary to drive the global economy to net zero by 2050. These prices were estimated by the European Investment Bank (EIB) as part of their Climate Bank Roadmap 2021-2025. (43)
The values were provided from 2020 to 2050 in 5 year intervals in Real 2016 Euros. We have filled in the interim values using liner interpolation and then applied appropriate inflation factors (44) and the current FX rate of 1.6 AUD/EUR to convert these values into 2024 AU$ Real.

This carbon price outcome might seem highly unlikely; however, it provides an upper bound to run as a sensitivity on gas demand.

Table 10 Summary of Carbon Price Scenarios (AU$/t$CO_2$)

Year	Reputex (Base)	AER (High)	EIB (Very High)
2024	48	70	
2025	62	75	
2026	63	80	
2027	64	84	
2028	70	89	
2029	85	95	
2030	96	105	507
2031	97	114	563
2032	93	124	620
2033	90	135	677
2034	89	146	733
2035	90	157	790
2036	95	169	845
2037	100	181	900
2038	105	194	954
2039	111	207	1,009
2040	117	221	1,064
2041	123	236	1,118
2042	130	252	1,173
2043	137	268	1,228
2044	144	286	1,283
2045	152	305	1,337
2046	161	325	1,394
2047	169	346	1,451
2048	178	369	1,508
2049	188	393	1,564
2050	198	420	1,621

6. Case construction

Construct cases representing a range of contextual factor outcomes with their corresponding input variable profiles.

Three distinct transition cases were developed based on different sets of assumptions regarding contextual factors and their impact on the development of the SWIS. Each of the three cases is intended to represent a plausible potential future based on assumptions regarding factors such as government policies and their implementation and effectiveness. The cases were used to develop corresponding schemes within the Gridcog modelling software. Additionally, the cases are used in the AGIG gas demand model in combination with the Gridcog scheme outputs to explore the potential future variations in gas volumes passing through the DBNGP.

In designing the Gridcog schemes, it was assumed there is no short term feedback loop between gas price and gas consumption for grid connected power generation, i.e., given a certain grid and power generation infrastructure configuration, the gas power generation will be dispatched to maintain a stable and reliable grid irrespective of the cost of gas.

The lead time to plan and build generation assets and supporting infrastructure means it is only possible for the SWIS, as an entire entity, to respond to longer term price trends and forecasts. Even in the longer term gas price will not be the only, or primary, driver of renewable generation and grid infrastructure build out.

Table 11 Summary of cases and corresponding Gridcog Schemes and key assumptions

Case	Base	Medium	Accelerated
Gridcog Scheme	Scheme 1	Scheme 2	Scheme 3
Domgas policy outcome	Success	Partial Success	Failure
Gas price scenario mean value	Low ($5/GJ)	BAU ($9+/GJ)	High - LNG netback ($13+/GJ)
Carbon price scenario mean value	Base	Base	Base
CPG[1] retirement	On Plan	On Plan	On Plan
Short to medium term renewables build out	CIS[3] aligned	RCM[2] aligned	RCM aligned+
Total renewables capacity CAGR 2023-2049	6.5% p.a.	7.2% p.a.	7.6% p.a.
Rooftop solar + DER[4] growth	Fast	Fast	Fast

1. Coal power generation
2. Reserve Capacity Mechanism
3. Capacity Investment Scheme
4. Distributed Energy Resources (Domestic batteries)

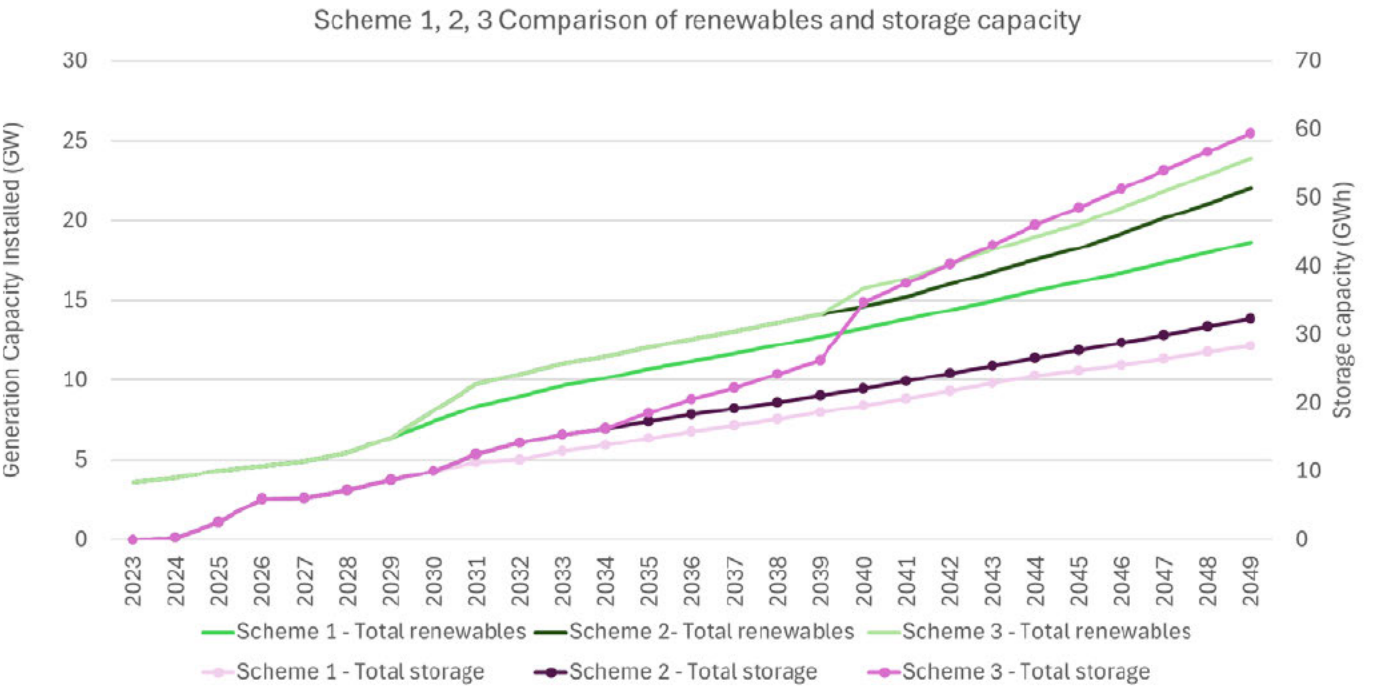


Figure 6: Comparison of renewables and storage capacity development over time across Schemes 1,2 and 3 (Note: All schemes overlap in the early years)

7. Forecasting gas demand for power generation

Use the developed cases as the basis for forecasting the range of gas demand for power generation and corresponding power generation mix over the period to 2050 using the Gridcog modelling software, with each case corresponding to a scheme in Gridcog.

Full details of how this was achieved, the model functionality and input assumptions can be found in the report section "Modelling electricity demand to forecast gas power generation – Details of Gridcog model", and subsections describing each Gridcog scheme in detail.

8. Electricity cost calculations

Use the developed cases combined with corresponding Gridcog scheme outputs as input data for electricity cost calculations.

Electricity pricing methodology

Electricity pricing within the AGIG demand model is dynamic and responds to the values of the selected input variables. The rationale for making electricity pricing dynamic is that gas price, carbon price, cost of renewables and share of renewables are all input variables and all impact the cost of electricity. For the economic decision logic to be sound these impacts need to be accounted for in the modelling.

The electricity price calculations have been specifically set up to calculate an average electricity price appropriate for a major industrial user. This considers the impact of being able to reduce the demand for power during periods of peak network demand and thereby reduce the capacity charges assigned under the Individual Reserve Capacity Requirement (IRCR). (45).

Build up of electricity price

Fixed Costs

These consist of network costs, market fees and other charges associated with connecting electricity generators to consumers.

Network costs

These have been estimated on a $/MWh basis in accordance with the price lists for the Western Power network using the progression of costs from FY15-FY25 based on the transmission exit service tariff (TRT1) (46) (47)
In real terms the Network charges have decreased very slightly (~1% p.a.) over the past decade but, as this trend is negligible, for simplicity charges have been rounded to one significant figure and held constant for the purposes of modelling. For FY25 costs are:

- ·Use of system price is 5.73 c/kW/day consistent with Alcoa Pinjarra substation
- ·Common service price is 6.032 c/kW/day
- ·Control system service price is 2.263 c/kW/day
- ·Fixed metering charge is negligible
- ·Average load is assumed to be 90% of Contracted Maximum Demand (CMD)
- This results in a network charge of (5.73 + 6.032 + 2.263)/24/0.9 = $6.49/MWh which has been rounded up to $7/MWh.

Market Fee

The market fee has been estimated based on the AEMO WA Budget and Fees documents (48) using the historical progression of costs since 2016 to infer future costs.

In real terms the market fee has increased by a CAGR of 6.1% since FY1631. Given the increasing complexity of managing the energy market through the transition we see no reason for this trend in increasing costs not to continue.

Table 12 Market fees used in electricity pricing

Time step	2030-35	2035-40	2040-45	2045-50
Fee (AU$/MWh)	2.91	3.92	5.27	7.08
Rounded (AU$/MWh)	3	4	5	7

Renewable Energy Target Liabilities

These currently equate to ~AU$18/MWh, however the Large scale Generation Certificates (LGCs) and Small scale Technology Certificates (STCs) used to achieve the goals of the Renewable Energy Target scheme are due to be discontinued beyond 2030 (49) and are proposed to be replaced by Renewable Electricity Guarantee of Origin (REGO) certificates (50). The REGO legislation is currently incomplete and the market and future costs of REGOs is uncertain. Therefore, for the purposes of modelling, we have provided an option to include a carbon price in electricity cost model beyond 2030 which adds emissions into the calculation of gas fired electricity costs[31]. The impact of this on the overall electricity cost varies depending on the carbon price and percentage of gas generation in the grid. As an example, at a carbon price of $75/tonne with 30% gas generation the cost would equate to ~$13/MWh distributed across all MWh dispatched.

31 See Excel file "Model Input Calculations" Sheet "Electricity cost" for details

Capacity (IRCR) charges

These are based on the Reserve Capacity Price which is calculated annually by AEMO based on a formula in the WEM rules. Forecasting the Reserve Capacity price is a study in its own right and we have therefore taken a view on how this will progress over time based on the knowledge and experience within Sunrise Energy Group.

Table 13 Capacity charges used in electricity pricing

Time step	2030-35	2035-40	2040-45	2045-50
Fee (AU$/MWh)	6.53	7.03	7.53	7.53
Rounded (AU$/MWh)	7	7	8	8

Power generation costs

Cost assumptions for all generation types have been taken from the CSIRO GenCost report 2023-24 (26)

Gas generators

For the gas generation assets, the capital cost is assumed to be covered by the capacity payments which gas generators should receive 100% of as they can reliably generate on demand and for an indefinite duration.

All gas generation has been treated as OCGT from a cost calculation perspective. This was done for the following reasons:

1. 1.Simplification of modelling
2. 2.Minimum historical difference between OCGT and CCGT generation costs in the SWIS (1)
3. 3.It is anticipated CCGT generators will be replaced by OCGT generators as the network continues to decarbonise requiring progressively more peaking generation vs baseload.

The variable operating costs used are an average of the small and large OCGT costs provided in the GenCost 2023-24 report.

Gas consumption was based on an average heat rate of 10.9 GJ/MWh. This was the average for all gas generators in the SWIS in 2023[32] and implies an average thermal efficiency of ~33%. This seems reasonable as generators will often be started and stopped and operated away from their best efficiency point which will reduce the average efficiency well below the optimum.

Note: *Typical optimum efficiency for a modern OCGT is ~35-40% and for a modern CCGT is ~50-60%. Under minimum load conditions this can fall to as low as ~25% (51)*

To apply a carbon price the emissions were calculated using the value of 51.53 $kgCO_2$/GJ for stationary combustion of natural gas distributed in a pipeline, as published in the Australian National Greenhouse Accounts Factors (52) Therefore, the average emissions intensity of gas power generation has be calculated as 10.9 x 51.53 = 562 $kgCO_2$/MWh.

Note: *Historical average emissions from gas power generation in the SWIS over the last 10 years range between ~560-580 kgCO2/MWh.*

32 See Excel "Model Input Calculations" Sheet "SWIS generation" for details

Large scale renewable generators

For renewable generation assets the GenCost 2023-24 report contains Levelised Cost of Electricity (LCOE) for "Variable with integration costs" between 60% and 90% VRE share of generation for the years 2023 and 2030. Using the same cost data and assumptions detailed within the GenCost report, we subtracted the cost of renewable generation from the VRE plus integration costs to establish the assumed costs of VRE integration on its own. We then projected integration costs into the future based on the GenCost projections of storage costs.[33]
The projected integration costs from 2030 to 2050 could then be added to the VRE LCOE costs for 2030 to 2050 which were calculated using the projected values and assumptions provided in the GenCost report.

For simplicity the VRE generation costs in any given time period are assumed to be the costs calculated for that period, i.e., the locked in cost of renewables already built up to that point is not accounted for. Therefore, the electricity price model is considered to be somewhat optimistic as the price decline in VRE is applied to all VRE capacity, both existing and new.

Note: The maximum decline in VRE with integration costs from 2030 to 2050 is from \$91 to \$70 (23%) for the 60% VRE share in the schemes that do not include offshore wind. At 60% of the generation mix this equates to <14% difference in total electricity price.

Rooftop solar (domestic and commercial)

Rooftop solar has been assumed to cost \$40/MWh throughout the modelling period based on the last 12 months average from OpenNem (1). This is somewhat arbitrary but, as it contributes only ~20% of the overall generation mix, a ± 50% variation in cost would change the overall delivered electricity cost by <5%

9. AGIG demand model

Use gas forecast gas demand for power generation, electricity calculation model and corresponding input variable profiles with a superimposed level of random variability, as inputs to the AGIG demand model to determine a range of potential industrial outcomes and future DBNGP gas throughput patterns.

Full details of the AGIG demand model can be found in the separate document entitled, "Attachment 6.1 – Future of Gas Rationale and Modelling Approach"

33 Details of the assumptions, rationale and calculations used to establish future costs of integration can be found in the Excel "Model Input Calculations", Sheet "AGIG Output"

Section 2 – Approach To Modelling

Modelling electricity demand to forecast gas power generation – Details of Gridcog model

Introduction

Realistic and defensible forecasting of gas demand for power generation is highly complex requiring modelling of the SWIS generation mix, storage and load over short time intervals, together with a number of input assumptions that must have sound rationale underpinning them.

For this portion of the work, CarbonTP engaged the services of Sunrise Energy Group who have built a simplified capacity model of the SWIS using the GridCog software package. Sunrise have previously performed similar work for a mining company wishing to understand the potential impact of the proposed coal fired power station closures on the SWIS.

The model was used to forecast peaking gas based power generation requirements and hence, when CCGT generation is added in, gas consumption for power generation can be estimated under different sets of input assumptions.

Meeting electricity demand in a capacity market

The nature of the SWIS as a capacity market has specific implications for how gas generators may choose to manage fuel supply in the future.
The SWIS is a capacity market and power suppliers into the market apply to provide generation capacity under the Reserve Capacity Mechanism (RCM) (53). Facilities are categorised by their facility “Class” and “Technology type” which effectively define their ability to provide capacity on demand and how long they can provide that capacity for. Taking these criteria and other factors into account each facility is assigned a Certified Reserve Capacity (CRC). Participants in the RCM are ultimately awarded Capacity Credits based on their (CRC).

Thermal generators able to generate continuously at will, e.g., gas turbines, are typically awarded much higher CRC values than intermittent generators such as solar and wind. The scheme has now been updated to includes Battery Energy Storage Systems (BESS) under the Electric Storage Resources Technology type. These must be able to deliver their certified capacity for a minimum of 4 hours to receive capacity payments.

If the DBNGP becomes a bottleneck, as may occur during periods of peak gas demand, generators who do not have reserved capacity may be unable to qualify for the RCM and, if they do qualify, may be unable to meet their CRC obligations and will not receive payment. The implications of this are:

1. Gas power generators will need to show they have guaranteed access to a fuel supply at all times to meet unpredictable peaks in demand or troughs in renewable generation and, under the current pipeline capacity contractual arrangements, they would need to contract for their maximum demand on an annual basis, irrespective of how frequently they use that capacity.
2. Contracting the full required capacity for infrequent use is likely to be cost prohibitive, even at very low pipeline capacity tariffs. This will potentially drive generators to use storage to meet demand peaks and only contract their maximum average demand over a multiweek period which would typically be in June / July when renewables output is at it lowest[34].
3. Fuel storage may be in the form of gas or distillate, and which is selected will be an economic optimisation based on factors including: required storage capacity, fuel cost, technology cost (dual fuel vs gas only), frequency of utilisation, security of supply to replenish, etc.

Gas demand for power generation post 2035 will be highly dependent on the growth in overall load and penetration of renewables and storage in the WA grid. With load growth following the projections in the 2023 Wholesale Electricity Market – Electricity statement of opportunities (WEM-ESOO) (2) and a linear projection of the levels of investment underwritten by the Federal Government's recently updated Capacity Investment Scheme (CIS) (54), as reflected in our base case, it seems likely that growth in load will not be wholly met by new renewables capacity Under these assumptions demand for gas to support GPG will continue to grow slowly out to 2050.

Assuming a more rapid build out of renewables and storage in line with the Reserve Capacity Targets provided in the 2023 WEM-ESOO (2), as reflected in our medium case, results in a flat profile for gas demand to support GPG firming. In this case, reflected in Gridcog Scheme 2, gas demand for GPG stabilises post 2035 and is relatively flat out to 2050.

Model scope

This subsection describes in detail the Gridcog model functionality and, considerations, inputs and assumptions required to perform the modelling of all the generation capacity and demand in the SWIS in 30 minute intervals and allow the model to solve for the make-up of generation to meet demand using OCGT gas peaking capacity

Generation and storage

The following generation sources and electricity storage solutions have been considered in the model. For details regarding the assumptions in relation to each generation source please see the section "Universal model inputs / assumptions relevant to main GridCog schemes" and additional details provided under the description of each Gridcog scheme modelled.

- Coal
- CCGT
- OCGT
- Wind
- Distributed SolarPV (e.g. Rooftop Solar, smaller commercial solar)
- Grid Scale (Large) SolarPV
- Battery Storage (Residential and Grid Scale)
- Distillate
- Landfill/Waste/Biogas

34 See Excel file "Storage Cost Assessment" for a perspective on the levelised cost of storing gas vs reserving pipeline capacity.

Modelling tool

The GridCog tool used for this modelling determines energy flows and associated cashflows enabling optimisation of resources to achieve lowest cost.

For this project Gridcog has been used for modelling energy flows only, to ascertain the quantity of gas peaking generation required in the SWIS based on input assumptions for other forms of generation and automated optimisation by GridCog of the charge and discharge schedule of the modelled energy storage assets.

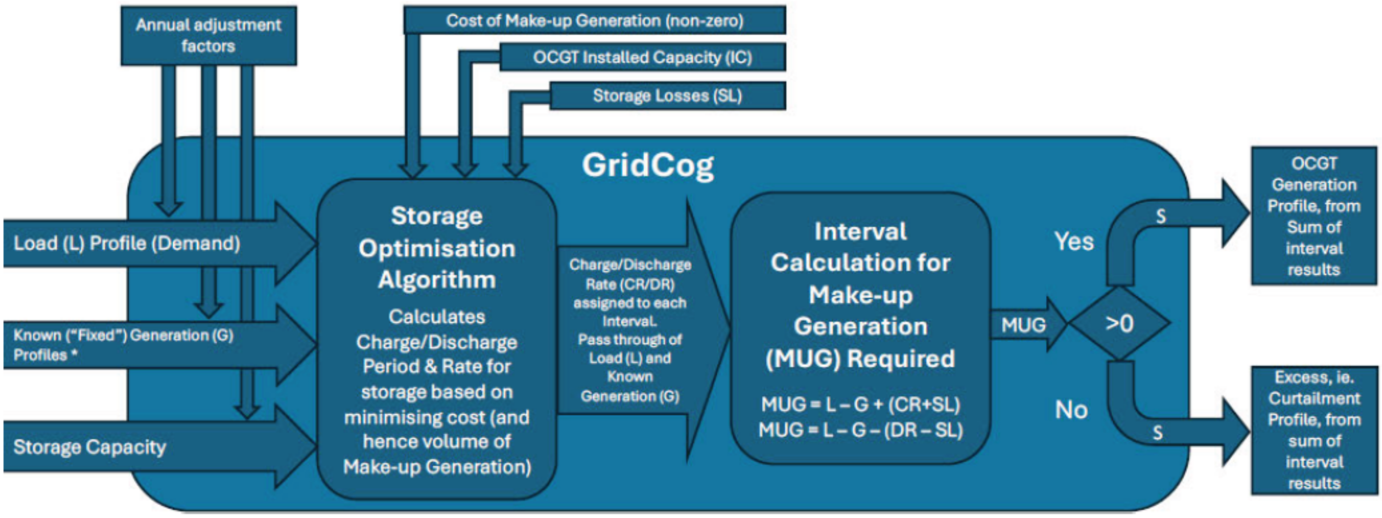


Figure 7: Functional Block Diagram of GridCog SWIS Model

Model inputs

Load Profile

This defines the gross load profile over time, i.e., TWh of electricity consumed annually as well as the pattern of that consumption, which includes seasonal and diurnal variation.

The demand is modelled in 30 minute intervals as gross demand using the 2023 demand data as a basis for future demand patterns. Demand includes total household demand and not the net system demand after rooftop solar has been deducted. Rooftop solar is included in the generation profile.

To decouple the feedback loops between the SWIS modelling and the overall gas demand modelling, the additional loads from electrification of large industries, e.g., alumina refineries, have been removed from the demand profile. Therefore, the overall demand for gas for power generation will be determined by totaling the forecasts from the SWIS modelling scope with the outputs from the gas demand modelling for any given time interval.

For example, Electrification of steam generation in an alumina refinery will add a significant load to the grid and this in turn will increase the demand for gas for firming power generation.

Note: It is recognised that electrification of industry is likely to add a less variable demand without diurnal variation, but with some small degree of short term flexibility. The net effect of this is expected to be a reduction in the diurnal variation in demand as a percentage of the average but this has not been modelled. Therefore, the patterns of gas firming required are likely to be slightly different than those modelled with incremental firming required overnight resulting in higher overall gas consumption than forecast in any given case.

Pre-defined Generation Profiles – The generation profiles are either:

A) a) For existing generators; e.g., coal, CCGT, distillate, Landfill/Waste/Biogas, existing wind and grid scale solar, based on 2023 actual data, with future profiles adjusted manually outside of GridCog according to stated assumptions, i.e., scaled up/down or removed due to a facility retirement.

B) For new renewables: wind, grid scale solar and rooftop solar, the future generation profiles are calculated by GridCog based on input data defining location, initially installed capacity and assumed annual capacity growth according to the stated assumptions.

Storage Capacity – This defines the total MWh of storage capacity available in the system during any given period together with other key characteristics; maximum charge and discharge rates and maximum state of charge and depth of discharge.

Annual adjustment factors – Due to the limitations of the Gridcog modelling software annual degradation typically observed in solarPV, wind and battery assets is not accounted for in the model. However, the impact of this degradation over the 20 year period being modelled is considered within the margins of error in the input assumptions. For example, assuming a 5% YoY growth rate with 1% annual degradation, typical of a battery cycled daily, results in the following differences in year 20.

- Total installed nameplate capacity = 2.65 x capacity in year zero
- Available capacity due to degradation = 2.3 x capacity in year zero
- Difference between adjusted and name plate capacity = 13%

If we adjust the assumed growth rate down by 1% the installed nameplate capacity in year 20 is 2.19 x capacity in year zero, i.e., a 1% difference in assumed growth rate is larger than the impact of capacity degradation over the same period.

Cost of Make-up generation (OCGT) – This is an arbitrary non-zero cost applied to the OCGT generation to force the model to use this last to balance the demand.

Storage losses – These are the round trip efficiency losses associated with charging and discharging a battery and have been set at 15%, i.e., batteries have an 85% round trip efficiency (RTE) broadly consistent with observed performance. (55) This is conservative for modern battery energy storage systems, but transmission losses during charging will effectively reduce the RTE depending on the location of the battery relative to the generation asset it is charging from.

Transmission and Distribution losses – These have not been accounted for in the mode and vary significantly depending on the location of the generator or load and how well utilised the lines are. Transmission losses in the SWIS can vary from almost nothing to ~20% for remote locations with high line utilisation. Distribution losses also have a high level of variation with values between ~0.5% and 30%. (56) Typically, the combined transmission and distribution losses across the network would be expected to be between 5-10%.

The net effect of including these losses would simply be to increase the apparent total load and their effect is considered to be well within the margins of error of load estimation.

Model functionality

The model balances supply and demand for each thirty minute interval by dispatching generation capacity to meet the instantaneous demand for that interval and optimising the charging/discharging of storage so as to minimise the overall cost and hence contribution of OCGT generation.

If the generation is greater than the total load at any given time the model will identify this as an excess and output it as a curtailment profile. The curtailment is not attributed to any specific generation source but serves to provide an overall indication of the development of excess generation capacity over time.

Methodology and validation

A base model was built using data from the 2022/23 financial year with the composition of generation capacity also derived from the data for that year but excluding OCGT generation. The model was then solved to determine the amount of OCGT generation dispatched to balance the grid and this value was compared with the actual OCGT generation dispatched in the year.

The model output was within 0.3% of the actual which is sufficiently close to provide assurance that the model is fit for purpose.

Universal model inputs / assumptions relevant to primary GridCog scenarios

- Model duration is out to 2049, i.e., 25 years starting from 2024.
- Modelling interval is 30 minutes, i.e., the model will reoptimise the generation every 30 minutes based on the supply demand balance.
- Relative price points for dispatch – non-zero for OCGT, zero for all other generators. This ensures the model optimises to find the lowest amount of OCGT generation required to meet demand in any interval.
- Load growth for the first 10 years is based on Figure 15 from ESOO 2023 (2), Ref. report with the following adjustment:
    - Included in the ESOO forecast is a sector of load growth assigned to "*Electrification: Business*". According to ESOO 2023, alumina refineries are forecast to be the largest contributor to this growth sector. As we are separately evaluating the electrification of individual large energy consumers such as the alumina refineries, this sector of the ESOO growth forecast was modified to remove a portion of the "*Electrification: Business*" sector. This was achieved by assuming the growth trajectory to 2028 was attributable to electrification of businesses other than large energy consumers and any growth beyond that trajectory could be attributed to electrification of large energy consumers. The modified trajectory is shown by the dashed red line added to the ESOO plot of load forecast (Ref. Figure 8). The portion of "Electrification: Business" above the dashed line was subtracted from the growth forecast.

      The annual quantities subtracted represent ~2/3 of the "Electrification" Business" load and are detailed in the table below.

Table 14 Industrial load subtracted from total load in relation to electrification of business

Year	2029	2030	2031	2032	2033
Load Subtracted (TWh/yr)	0.5	1.78	2.86	3.73	4.45

Note: 1 TWh/yr is equivalent to ~114 MW continuous load, therefore the load subtracted in 2033 is equivalent to ~510 MW. For context the estimated additional load from full conversion of all 4 of the state's alumina refineries to MVR is ~900 MW. Ref. MVR Retrofit and Commercialisation Report p.74 (8)

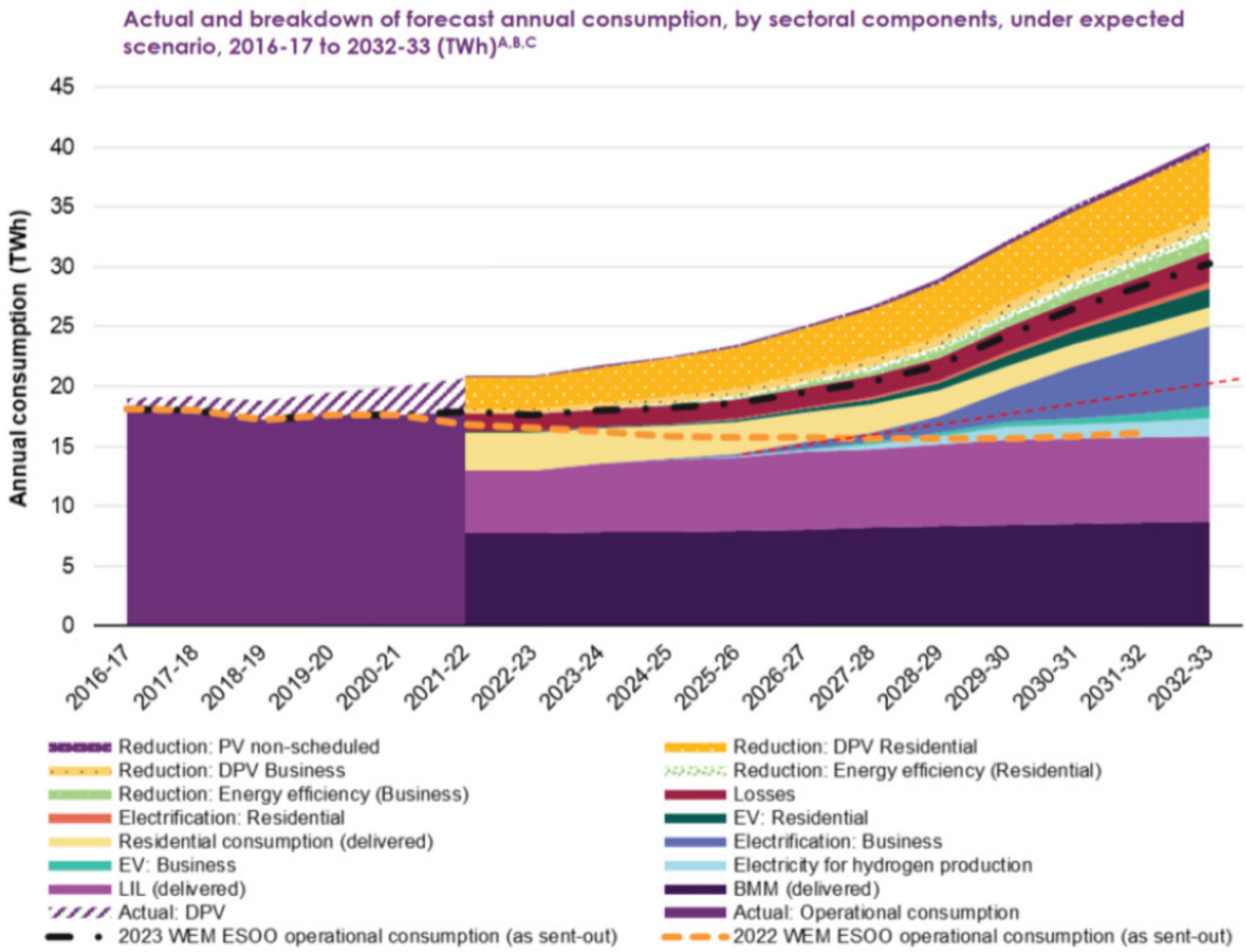


Figure 8: Forecast electricity demand over next 10 years extracted from 2023 Wholesale Electricity Market Electricity Statement of Opportunities report.

From year 10 load growth is assumed at a compound rate of 3% p.a. marginally below the trend established in the ESOO as illustrated in Figure 9 below.

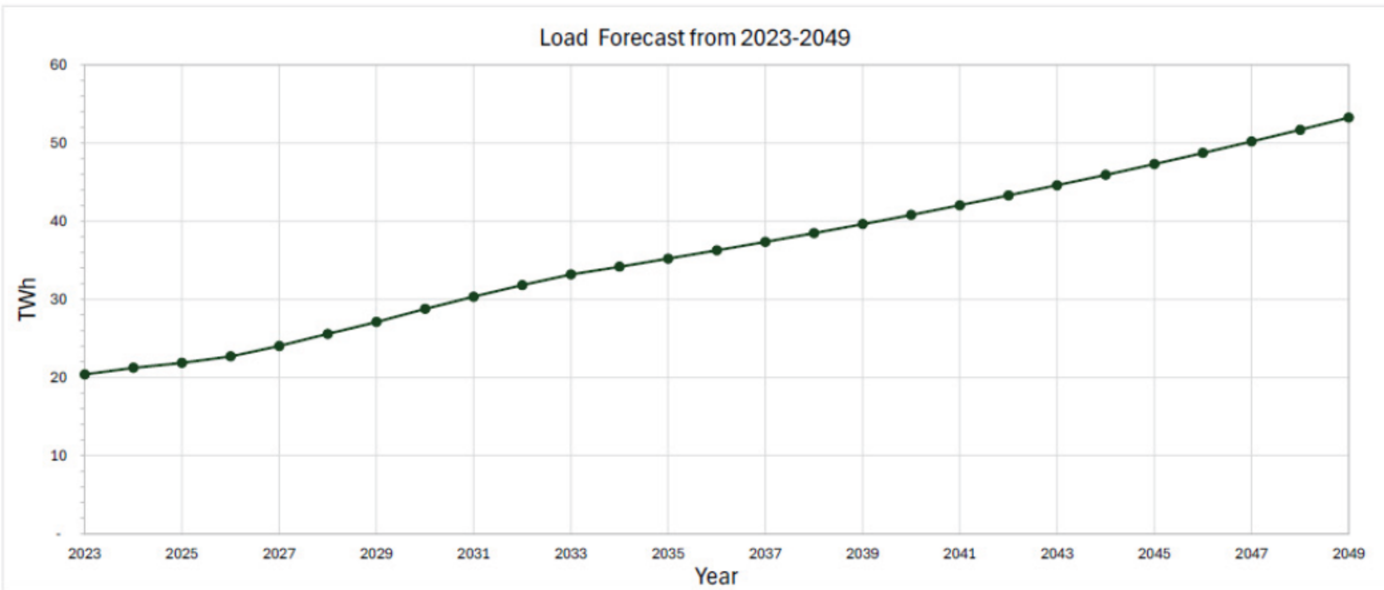


Figure 9: Forecast electricity demand out to end 2049

- New wind generation that is not already a defined project with a known location is assumed to be distributed across several likely locations (Albany, Arrowsmith and Merredin) with generation profiles based on internal GridCog wind data according to the selected locations and with output scaled to deliver a capacity factor of 40% to align with existing wind farm outputs.
- Build out of the SWIS grid is assumed to be sufficient to support connection of all new generators and loads in all schemes, i.e., the transmission infrastructure does not limit the ability of new renewable generators to deliver power to end users.

  Note: *The above assumption is considered to be optimistic and there is a significant probability that the transmission network will continue to be a bottleneck in the growth of grid connected renewable generation capacity. This outcome would lead to higher gas consumption for power generation.*

- Generation profile data for all pre-existing wind farms and grid scale solarPV is based on 2023 data.
- New Grid Scale Solar is based on single axis tracking with generation profiles based on GridCog internal estimate as per ESOO (2)
- Coal retirements occur as they have been announced:
  - Muja Generator 6, retired end of 2024[35]
  - Collie, retired end of 2027
  - Muja Generators 7 & 8, retired end of 2029.
  - Bluewaters retired end of 2030 (AEMO Estimate) (2) (57)

Note: *Spot electricity market settlement prices will progressively be determined more and more frequently by OCGT generators as demand increases and coal retires. This will result in increased electricity prices. However, as the majority of the market is covered by bilateral agreements the effect of this on overall electricity prices is considered unlikely to be high enough for the State Government to defer the shut down of the coal fired generation.*[36]

- When a coal fired power station is retired, none of that load is taken up by the remaining coal power stations and the previous coal generation profile is picked up by CCGT[37] up to a limit of 90% utilisation of existing CCGT capacity. The rationale for this is:
  - The purpose of shutting down coal fired generation is to reduce emissions. If the output of a retired coal fired power station is taken up by the remaining coal fired power stations that would defeat the object of shutting them down.
  - CCGT is more attuned to base load generation and more efficient than OCGT and it is a reasonable assumption that gaps in base load generation left by coal would be more effectively served by CCGT than OCGT
  - When the final CPG is shut down the only synchronous generators in the SWIS will be CCGT and OCGT. For the foreseeable future it is assumed that some of this capacity will need to be in permanent operation to maintain grid stability and provide sufficient system strength to manage anomalous events.
  - The Economic Regulation Authority Generator Availability Analysis report 2020 section 3.2.2 indicates GPG units in the WEM had an average availability of 91% during the previous 10 years. (58)

- New OCGT capacity is built and connected as required to meet demand at all times. There are periods beyond 2033 where the current combined CCGT + OCGT capacity is insufficient to meet the modelled peak demand, resulting in unserved load unless new capacity is deployed.
- Existing CCGT capacity continues to operate to 2049. Typical technical life of CCGT plants in continuous operation is 25-30 years, although with appropriate maintenance this can be extended to 40+ years.
- Distillate (diesel) based generation is not accounted for. This would only be dispatched once all GPG was at full capacity and it is therefore assumed will not impact gas consumption for power generation except in the event there is insufficient GPG capacity available, i.e., due to equipment failure, planned maintenance. There is currently ~120 MW of distillate based generation available to meet peak demand and this would pick up unserved load up to the available capacity subject to real world constraints.

35 Pushed back to April 2025 to provide cover for summer peak demand, however this will not have any material impact on model outcomes post 2030.
36 WA is a regulated capacity market and as such the capital depreciation and fixed costs of thermal generators are currently covered by Reserve capacity payments. Therefore, the bid cost per MWh for an OCGT is only reflective of the variable operating costs, most of which are fuel costs. Gas at $10/GJ equates to a fuel cost of ~$120/MWh.
37 This assumption is further explored in some sensitivity cases which assume different levels of CCGT generation.

- Distributed PV (mostly rooftop solar) exhibits average linear growth of 12% annually for the first 10 years based on ESOO 2023 (2) and then grows linearly by 4.6% per annum. This is aligned with the CSIRO report "Small-scale solar PV and battery projections 2022" (59) which describes the following four scenarios: Progressive Change, Exploring Alternatives, Step Change and Hydrogen Export. The "Step Change" scenario has been assumed. The rationale for using an accelerated deployment scenario is based on the strong support demonstrated by the state government for Distributed Energy Resources (DER) including a proposal to include aggregated DER of capacities > 1MW in the Reserve Capacity Mechanism with a view to making them more commercially viable. Ref. WA DER Market participation forum. (60)
- Generation from Distributed PV is based on 15.5% capacity factor as nominated for WA in CSIRO report "Small-scale solar PV and battery projections 2022" (59)
- Rooftop solar generation will be calculated based on the following orientation assumptions; North 80%, West 15%, East 5% and with a tilt of 20 degrees consistent across all orientations. These assumptions are an interpretation of the CSIRO report (59) which indicates ~90% of rooftop solar has been installed with North orientation with the remainder being mostly West orientated and a small percentage of East orientation. It is also anticipated in the report that North orientation installations will drop to 70% by 2050, with a greater incentive for west orientation targeted at serving the evening peak demand period.
- Residential/DER battery storage of 4 hours duration based on CSIRO report (59)
  - 20MWh base in 2023 with linear growth at 96MWh/yr to 500MWh in 2028
  - Linear growth at 281 MWh/yr to 6,400 MWh in 2049

Note: *Assuming an average residential battery size of 10 kWh the above capacities imply 50,000 household batteries by 2028 and 640,000 by 2050.*

- Announced wind and solar farm projects progress as planned:
  - Flat rocks Stage 1 – 76MW wind farm is included in 2025. Generation profile is based on internal GridCog wind data according to its location and scaled to deliver a capacity factor of 40%.
  - Cunderdin 100 MW AC solar farm is included in 2025
- Announced grid scale batteries are connected as planned:
  - 2024: Kwinana KBESS1 (100MW/200MWh)
  - 2025: Kwinana KBESS2 (200MW/800MWh), Cunderdin (50MW/220MWh), NEON Stage 1 (219MW/877MWh), Alinta Wagerup (100MW/200MWh)
  - 2026: CBESS (500MW/2000MWh), NEON Stage 2 (341MW/1363MWh)
- Grid scale Battery Storage is assumed to be lithium-ion, with 90% depth of discharge and 85% round trip efficiency. Degradation is not modelled due to the constraints of the Gridcog software. See "Annual adjustment factors" under " Model inputs". There are no limits on frequency of battery cycling although it is anticipated most batteries will typically undergo a daily cycle to time shift rooftop solar from peak generation in the afternoon to peak consumption in the evening.
- Battery charge and discharge timing is determined via the GridCog optimisation algorithm.

  Note: *This is not how the market currently incentivises battery owners to operate their assets, with incentives typically designed to promote charging between 10am and 2pm and discharging between 4:30pm and 8:30pm. The market prescribed scheme was modelled initially but proved to be sub-optimal when compared to the GridCog optimisation algorithm and resulted in greater overall OCGT generation. With more and larger battery assets being added it is likely they will be managed by real time optimisation algorithms in the future, resulting in similar charge/discharge patterns to the model predictions.*
- Allocation of reserve capacity credits for solar, wind and battery storage are assumed to be 14%, 15% and 92.5% of installed capacity respectively. This is based on average factors assigned in the latest reserve capacity allocation round.

Consideration of the impact of electric vehicles

By default, power demand for EVs has been built into the modelled future total SWIS demand profile. However, the percentage of the total demand allocated to EVs has not been assessed or modelled and the potential impact of using EV battery storage for energy arbitrage and grid services has also not been included in the modelling, as the levels of uncertainty around EV uptake, provision and functionality of supporting infrastructure, charging patterns, and overall impact on the grid is extremely high.

Our conclusions on semi-quantitively assessing the likely impact of EVs across all vehicle categories is that they will represent a significant quantity of storage by 2050, Est. 80-200 GWh, and add significant load to the grid Est. 4-12 TWh annually. However, it is likely the majority of the load will be overnight when most EVs will be plugged in and charging. Therefore, EVs are unlikely to make a significant contribution in shifting peak daytime solar generation to serve the evening peak demand and may actually require additional storage to be added to the grid to serve the overnight charging demand.

Additionally, EVs cannot be relied on to provide support for the grid during an extended renewables drought as there is no guarantee they will be connected and EV owners are considered more likely to look after their own interests first rather than risk draining their battery to support the grid.

Due to the fact that they add load, it is considered EVs may actually increase the demand for gas fired power generation in the future. See bullets in support of this position.

Total EV fleet battery capacity and grid impact in 2050

To estimate the EV fleet battery capacity and grid impact in WA in 2050 we took the following approach[38]:

- Understand recent trends in vehicle numbers and categories in relation to population, i.e., number of each type of vehicle per one thousand head of population, from the Bureau of Infrastructure and Transport Research Economics data (61)
- Forecast number of each category of vehicle per one thousand head of population in 2050

Note: Two cases were explored, one based on observed trends in increasing numbers of commercial vehicles per head and one based on recent average numbers of commercial vehicles per head.

- Understand future population trends from the WA population forecast (62) and project population of WA in 2050
- Calculate total numbers of each category of vehicle in 2050 based on projected population multiplied by number of each category of vehicle per one thousand people
- For each vehicle category, forecast the percentage of the vehicle fleet that might be EVs in 2050 based on a forward projection of the Austroads Future Vehicle Forecasts Update 2031 (63) using the medium uptake trend and scaling percentages for different vehicle types, e.g., buses might be expected to have 80% penetration as they are the ideal EV use case.

Note: A sensitivity case was also run based on the low uptake trend resulting in values that were ~50% of those based on the medium uptake trend.

- Calculate the total number of EVs in each category of vehicle by multiplying the projected total number of vehicles in that category by the forecast percentage EV fleet penetration.
- Estimate typical battery size for each type of EV based on experience and current trends.
- Calculate total EV population battery capacity across all vehicle categories by multiplying projected number of EVs by estimated battery size for each category.
- Estimate annual km per vehicle category based on data from the most recent Survey of Motor Vehicle use (64)
- Estimate average efficiency of each vehicle category in terms of kWh/100km based on currently available data.
- Calculate annual load for each vehicle category by multiplying projected km by efficiency and EV population.
- Estimate number of operational days for each vehicle category.
- Calculate daily charging requirements and power demand for each vehicle category by dividing annual load by number of operational days.

Based on a projected 2050 WA population of ~4.5 million the results of the above process are summarised in Table 15 below for the vehicle categories of significance.

38 Details can be found in the Excel file “Model Input calculations.xlsx”, sheet “BEV Analysis”

Table 15 Projected EV fleet data for 2050

Vehicle category	Passenger (Private car)	Light Commercial	Light rigid truck	Heavy rigid truck	Heavy rigid truck	Bus	Totals
Vehicles per 1,000 population	600	270	8	29	13	9	
Total number '000s	2,700	1,200	37	130	59	40	
Percentage of EVs in fleet	60	60	40	40	40	80	
Number of EVs '000s	1,600	790	21	66	24	40	
Battery capacity (kWh)	60	80	120	220	600	300	
Fleet capacity (GWh)	100	60	2	12	14	10	198
kWh/100km	14	21	35	75	170	170	
Average Annual km	11,300	14,900	16,000	16,000	68,000	24,500	
Days used per year	365	365	260	260	260	280	
Annual load (TWh)[39]	3.2	2.8	0.1	0.8	3.4	1.7	12
Charging requirement on days of use (GWh)	8.9	7.8	0.4	3.0	13	6	39
Average power demand on days of use (MW)	370	320	20	130	550	250	1,640

***Note:** There are a lot of highly uncertain variables involved in these calculations and the above table represents only one potential outcome. Of equal/greater importance is the usage and charging patterns of EVs and how they may or may not support the grid.*

For reference, the forecast annual demand of ~12 TWh for EVs of all categories in 2050 based on our approach is proportionately much higher than extrapolating the 2023 AEMO ESOO (2) which only extends to 2033 and forecasts EV demand across business and residential of 2.6 TWh in FY33 in their "Expected scenario". This is most likely due to assumptions around rate of EV uptake which is highly uncertain and could change very rapidly.

However, our sensitivity case using the low uptake trend from the Austroads report (63) and lower proportion of commercial vehicles per head of population, results in an annual electricity demand for EVs of all categories of ~4 TWh in 2050 which is more aligned with a projection of the 2023 ESOO.

38 Details can be found in the Excel file "Model Input calculations.xlsx", sheet "BEV Analysis"

Evaluation of impact of EVs on the grid

- By 2050 it is anticipated there will be between 80 GWh and 200 GWh of EV battery capacity deployed in WA across all vehicle categories, with annual charging demand of 4-12 TWh/yr
- It is anticipated the majority of privately owned passenger vehicles will be in use during the day and charged at home overnight unless there is a proliferation of tens of thousands of charging points made available to facilitate low cost daytime charging during peak rooftop solar output. It is difficult to conceive of a commercially viable model where low cost solar power is delivered to those tens of thousands of charge points at a sufficiently low cost to incentivise EV owners to charge during the day whilst also cover all existing network charges and paying back the cost of installing all the necessary infrastructure with some profit margin. Therefore, it is considered unlikely that privately owned passenger EVs will provide a significant benefit time shifting peak solar to evening peak demand.
- The previous bullet point is supported by learnings from Western Power's Project Symphony indicating there is a limited business case for Virtual Power Plant (VPP) providers to make money from providing services to the SWIS. (65). From section 5.2 of Project Symphony lessons learned report, "The Project Symphony Cost Benefit Analysis highlighted that more work was required to establish a viable Third Party Aggregator (TPA) business model. TPAs had a negative Net Present Value due to bearing the full cost of orchestration relating to the integration of their systems with the Aggregator Platform, system access fees, and payments to customers. Though they receive revenue from Synergy, the value of this benefit is outweighed by the combined costs."
- The cost of retail electricity in WA is ~$0.33/kWh of which <30% ($0.10) is the wholesale electricity price. Even with negative wholesale prices it is difficult to see EVs plugged in at home being able to regularly access excess retail electricity for <$0.10/kWh delivered, or regularly sell it back to the grid for much more than $0.15/kWh during periods of peak demand. Even assuming 20 kWh arbitrage per EV per day would only generate $1.00 revenue which is not considered enough to justify the necessary investments to support at scale investment or to incentivise users to sign up their EVs to participate in Virtual Power Plant schemes.
- A proportion of private passenger EVs will be used behind the meter to provide local time shifting of self generated rooftop solar to evening peak and overnight consumption, but only those that are parked on the drive and plugged in during the daytime will be able to take advantage of this. Assuming 20% of the total passenger EVs are plugged in for 50% of the 6hr peak solar window and able to charge at 3 kW implies between 1.2 to 3 GWh of storage would be useable. This compares with a range of 28 to 59 GWh of permanently connected domestic and grid scale storage assumed in the different schemes modelled and is therefore not considered material.
- The total battery capacity of commercial EVs in 2050 is anticipated to be similar to that of privately owned passenger vehicles. However, it is expected, even more so, that these will be in use during the day and charged overnight and therefore provide little benefit in terms of time shifting solar generation to the evening peak.

GridCog Scheme 1

Inputs and Assumptions aligned with the Domgas policy Success case and corresponding lower gas price profile – See Table 11

Rationale

Lower gas prices make renewables less competitive, particularly at the higher penetration levels required to start significantly eating into gas demand. Additionally, the financial incentives for electrification are weak or may fail to emerge completely, even when carbon pricing is considered. (50/tCO2-e translates to an equivalent of only $2.50/GJ increment in gas price).

Reserve Capacity Payments made to renewable generators under the Reserve Capacity Mechanism (53) are typically based on 10-20% of the installed capacity vs 100% for a gas generator. Therefore, a shortfall in capacity which drives up capacity prices is a much larger incentive for new gas generation capacity than new renewables capacity.

With the expiry of the Federal Government's renewables and storage targeted capacity investment scheme in 2030, the growth in renewables and storage capacity is led only by load growth and is more reactive than pro-active with shortfalls in peak capacity being met by demand response and/or incremental gas peaker capacity.considered more likely to look after their own interests first rather than risk draining their battery to support the grid.

Due to the fact that they add load, it is considered EVs may actually increase the demand for gas fired power generation in the future. See bullets in support of this position.

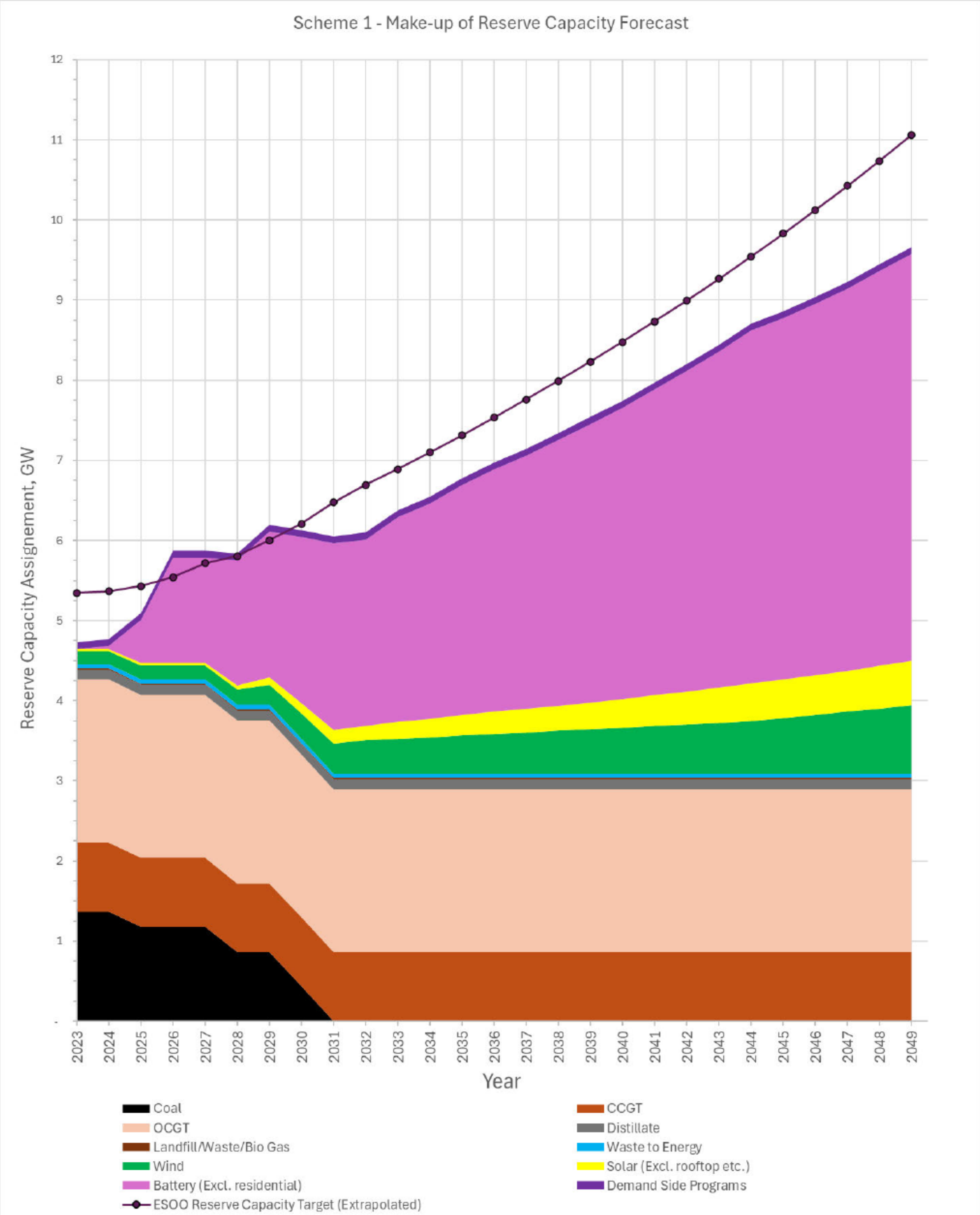


Figure 10: Scheme 1 Reserve Capacity make up to deliver CIS funded capacity to 2030 indicates shortfall beyond 2030 vs 2023 ESOO Reserve Capacity Targets.

Detailed inputs / assumptions

- 6.5TWH of additional variable renewable energy (VRE) generation and 1.1 GW of additional 4 hour duration storage added by end of 2030 (DCCEEW-CIS aligned) (54) The assumed new capacity to satisfy this is:
  - 1300MW of new wind farms with 40%[40] capacity factor by end of 2030 with timing of connection as follows:
    - 10% installed by end of 2027
    - 40% by end of 2028
    - 70% by end of 2029
    - 100% by end of 2030
  - 1000MW of grid scale Single Access Tracking PV with 25% capacity factor by end of 2030 with timing of connection as follows:
    - 10% installed by end of 2027
    - 40% by end of 2028
    - 70% by end of 2029
    - 100% by end of 2030
  - 1100MW of 4 hrs grid scale battery storage added by 2030
    - 25% installed by end 2027
    - 50% by end of 2028
    - 75% by end of 2029
    - 100% by end of 2030
- This level of investment in new capacity is insufficient to meet the 2023 ESOO Reserve Capacity Targets out to 2033 or the projected capacity targets beyond that.
- Renewables capacity additions beyond 2030 are assumed to match or marginally outpace the growth in load resulting in a very gradual decarbonisation of the grid, i.e., the total Terawatt hours generated from the new renewable capacity are sufficient to supply marginally more than the additional Terawatt hours of load. For example, if the annual load grew by 1 TWh, equivalent to ~114 MW of 24/7 demand, this would be assumed to be served by addition of >325 MW of combined wind and solar with an average combined annual capacity factor of ~35%. This results in growth of ~5% p.a. in renewables capacity
- Grid scale storage capacity additions beyond 2030 are scaled to maintain a constant ratio with the total GWh of solar generated (Grid scale + rooftop PV). The net effect of this is to gradually increase the proportional level of firming available over time when grid scale storage is considered together with household batteries.

40 The 40% capacity factor assumption for wind was determined as follows: GridCog has useful internal wind generation profiles however, experience with the tool has shown that total predicted generation can be misaligned with actual output from existing assets. Therefore, the wind profile outputs from GridCog have been scaled to a capacity factor of 40% which aligns with existing wind assets in the state as evidenced by this RenewEconomy article (68). In further support of the 40% value the CSIRO GenCost report 2023-24 (26) indicates typical capacity factors of 29% to 49% with 40% being in the middle of this range.

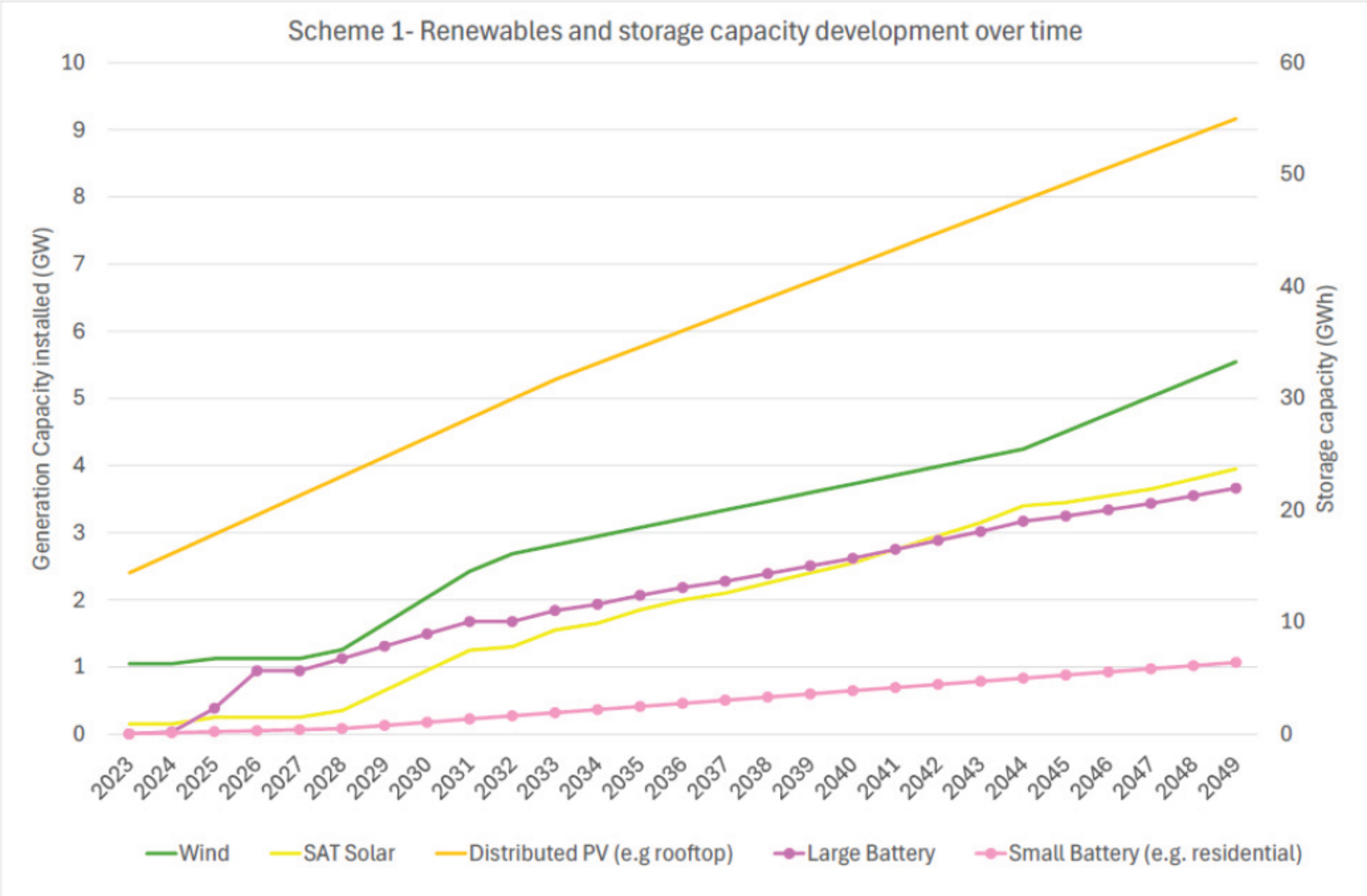


Figure 11: Renewables and storage capacity development in the SWIS – Scheme 1

CARBON TP

GridCog Scheme 2

Inputs and assumptions are aligned with the Domgas policy partial success case – See Table 11

Rationale

Build out of renewables and grid scale storage between 2025 and 2029 is aligned with the recently announced Department of Climate Change, Energy, the Environment and Water (DCCEEW) Capacity Investment Scheme (CIS) – Western Australia Design Paper (54). It is considered unlikely there will be incremental build out of renewable generation capacity beyond that underwritten by the CIS in this time frame as any additional capacity would be taking on a significantly greater commercial risk and would be unable to compete for capital with projects covered by the CIS.

From 2030 additional renewables and storage capacity are added over and above that supported by the CIS to meet the ESOO reserve capacity targets (RCT) to 2033 (2). Beyond 2033 capacity is added to meet a projected capacity target generated by extrapolating the established trend in ESOO RCT values.

In developing this scheme, it is recognised there is currently no investment certainty to incentivise the projects necessary to deliver this additional capacity however, it can be imagined that this may come through additional phases of the CIS and/or independent State or Federal incentive schemes

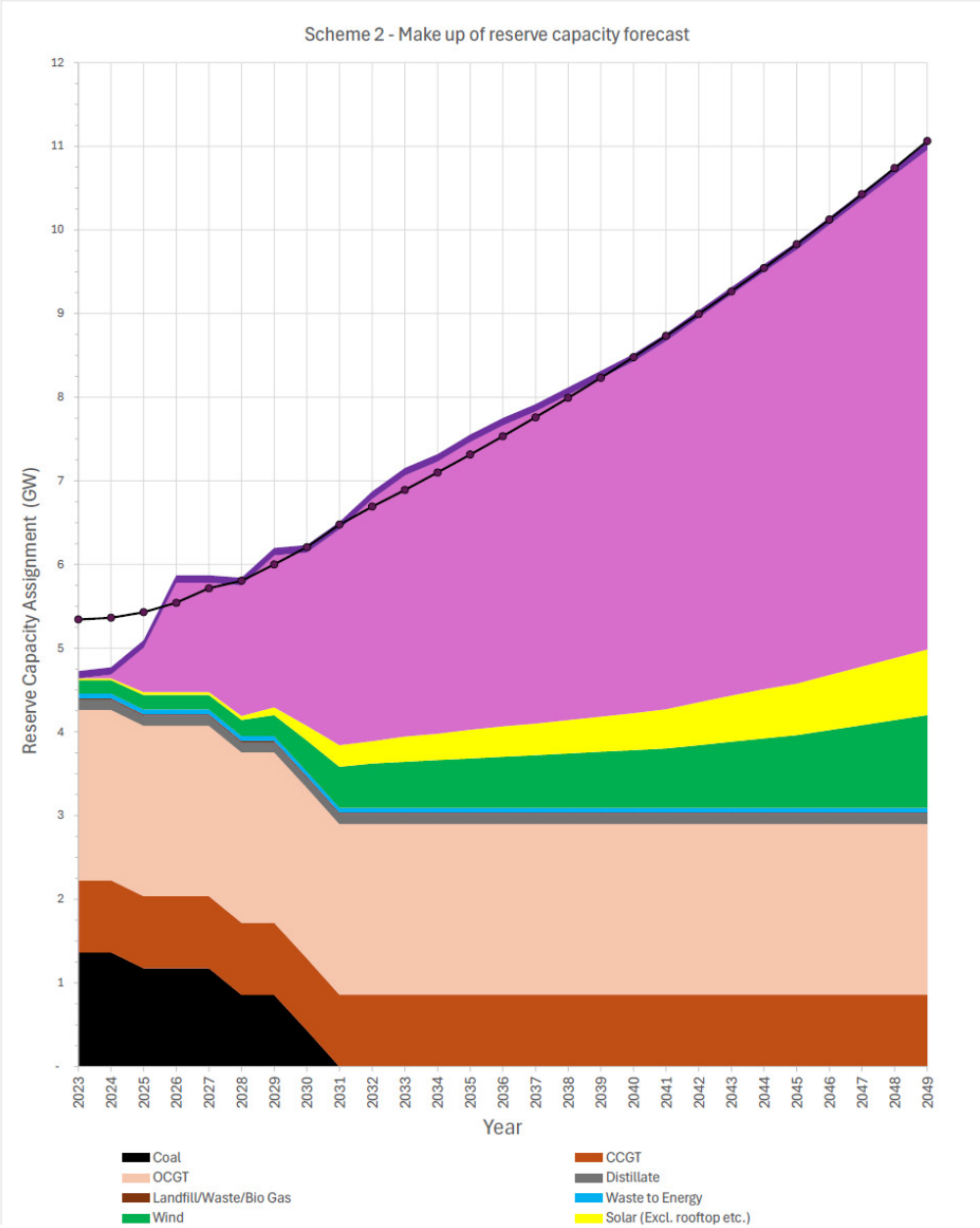


Figure 12: Scheme 2 Reserve Capacity make up to deliver CIS funded capacity and meet targets extrapolated from 2023 ESOO Reserve Capacity Targets

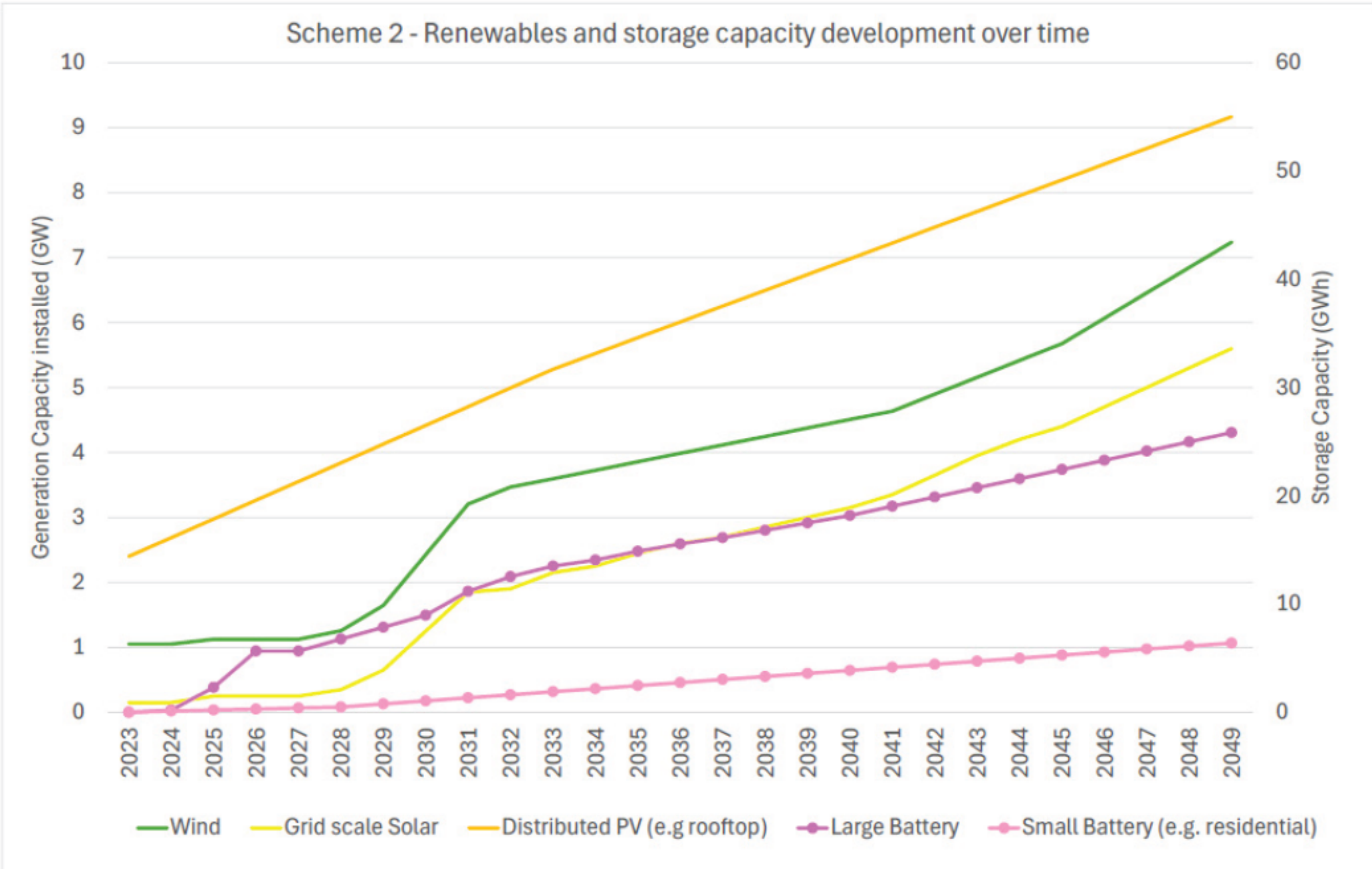


Figure 13: Renewables and storage capacity development in the SWIS – Scheme 2

GridCog Scheme 3

Inputs and Assumptions aligned with the Domgas policy failure case and corresponding higher gas price profile – See Table 11

Rationale

Higher gas prices make renewables and storage more financially attractive and commercially viable vs gas fired generation. Renewables are more competitive as an energy source at much higher levels of grid penetration even when the additional storage, infrastructure requirements and curtailment are accounted for.

Higher gas prices also provide a strong incentive to minimise gas generation and therefore in this scenario it has been assumed that all GPG capacity is operated 100% flexibly to meet demand, rather than CCGTs providing a prescribed base load. This assumes that technology is available to operate the grid without synchronous generators online at all times, with batteries regulating frequency and providing adequate system fault tolerance.

Renewables generation and storage capacity is installed over and above that required to meet the reserve capacity targets.

Detailed inputs / assumptions – Differences from Scheme 2

- 1 GW of offshore wind at 55% capacity factor comes on-line in 2040 generating 4.8 TWh per year equivalent to ~12% of total forecast load in 2040.
- Additional 900 MW of grid scale solar deployed between 2040 and 2049 generating an additional ~2 TWh per year
- Longer duration storage (10 hr) added from 2035 to 2040 with an additional 6.5 GWh storage added as a lump in 2040 to complement the offshore wind capacity. Further increments of long duration storage out to 2049 complete the addition of ~27 GWh of grid scale storage above Scheme 2, i.e., more than double.
- In this scheme the model was allowed to treat all gas capacity as flexible without a prescribed baseload of CCGT generation.

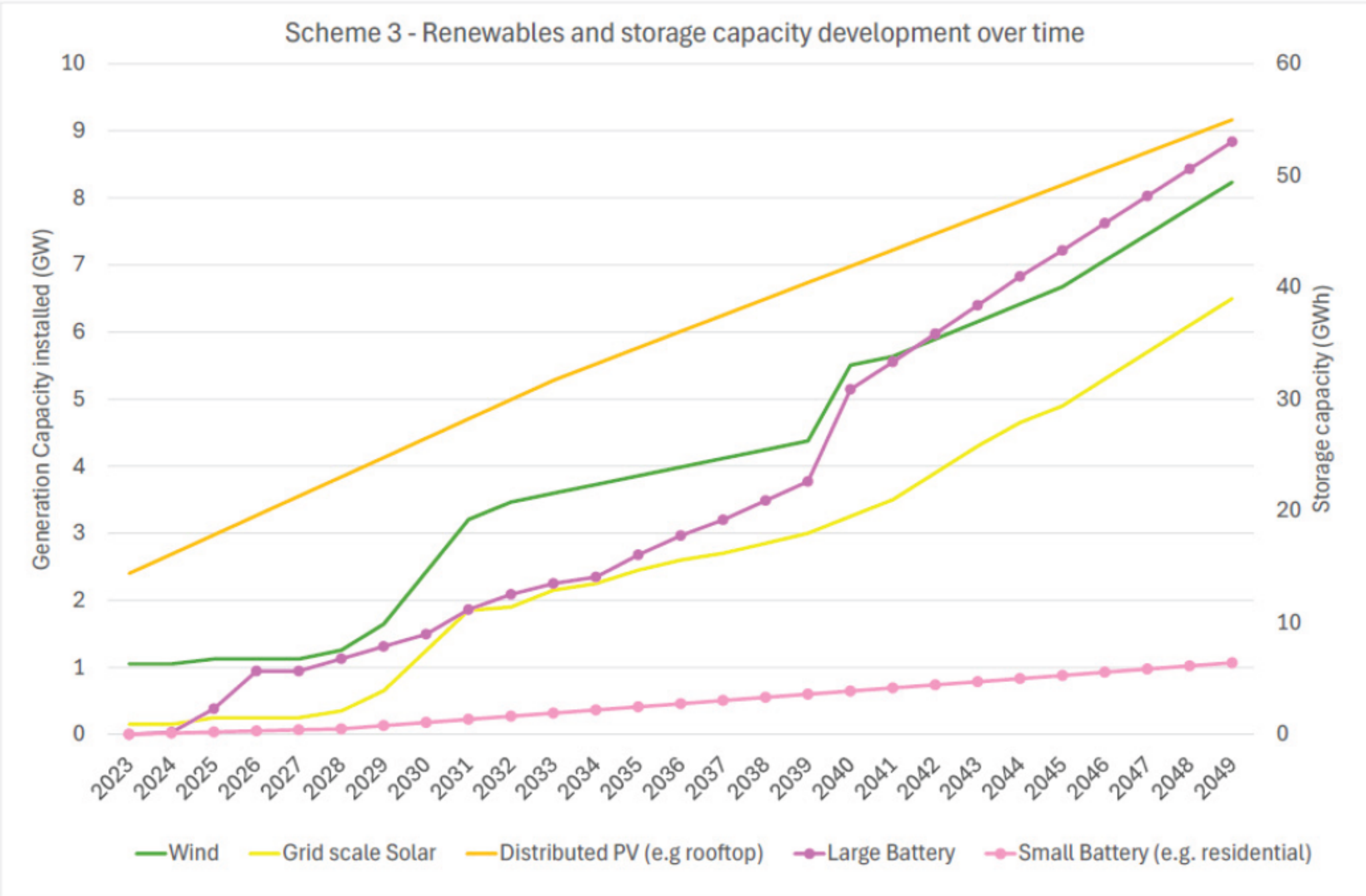


Figure 14: Renewables and storage capacity development in the SWIS – Scheme 3

This scheme will result in a substantially lower demand for GPG as it significantly increases the quantity of renewable generation capacity and storage deployed for the same load profile.

Rooftop solar and DER remain unchanged as they are already on an accelerated trajectory in the Base Scheme

Section 2 – Approach To Modelling

Gas demand for GPG - Model insights

Scheme 1

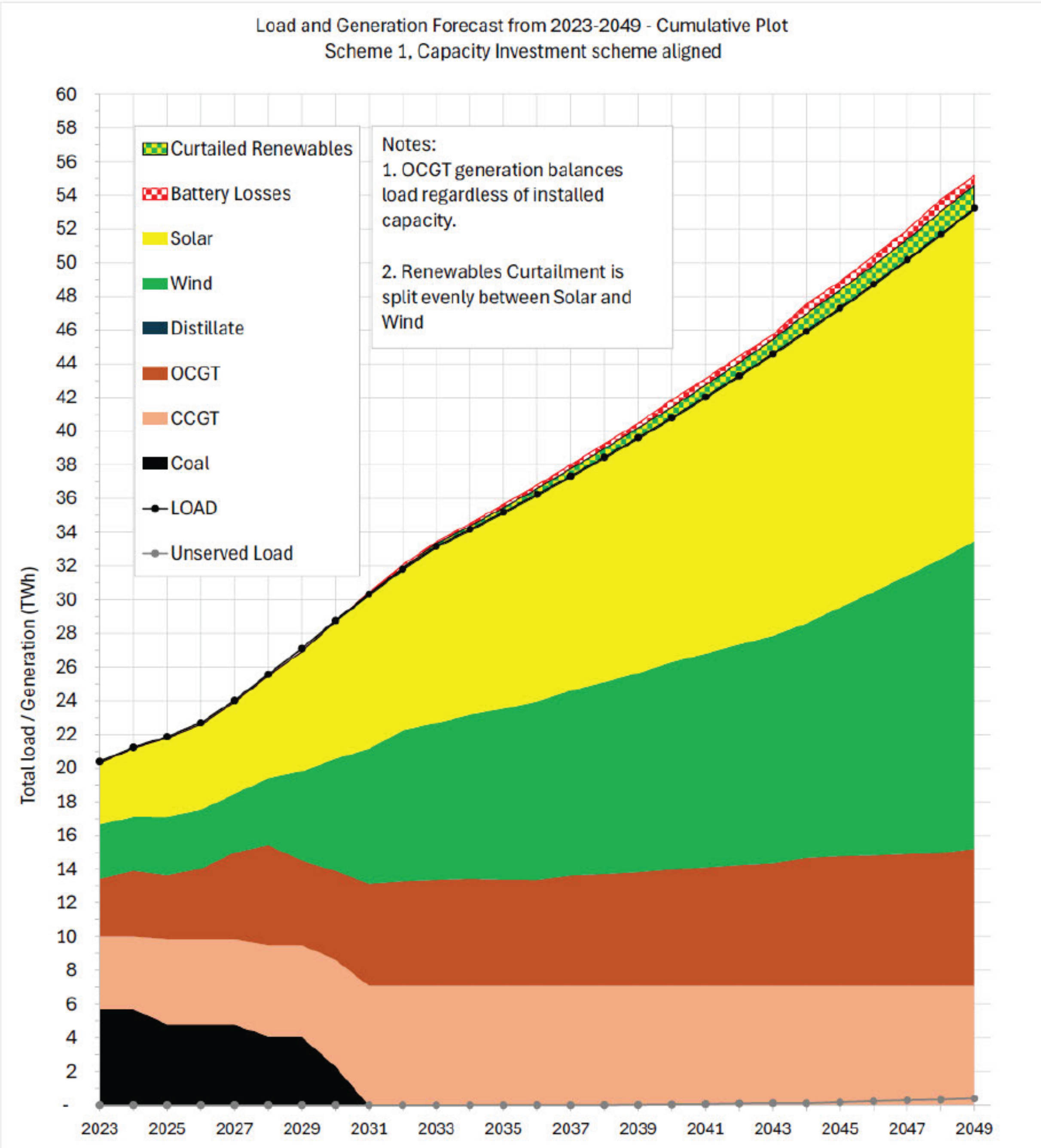


Figure 15: Scheme 1 – Cumulative generation profiles

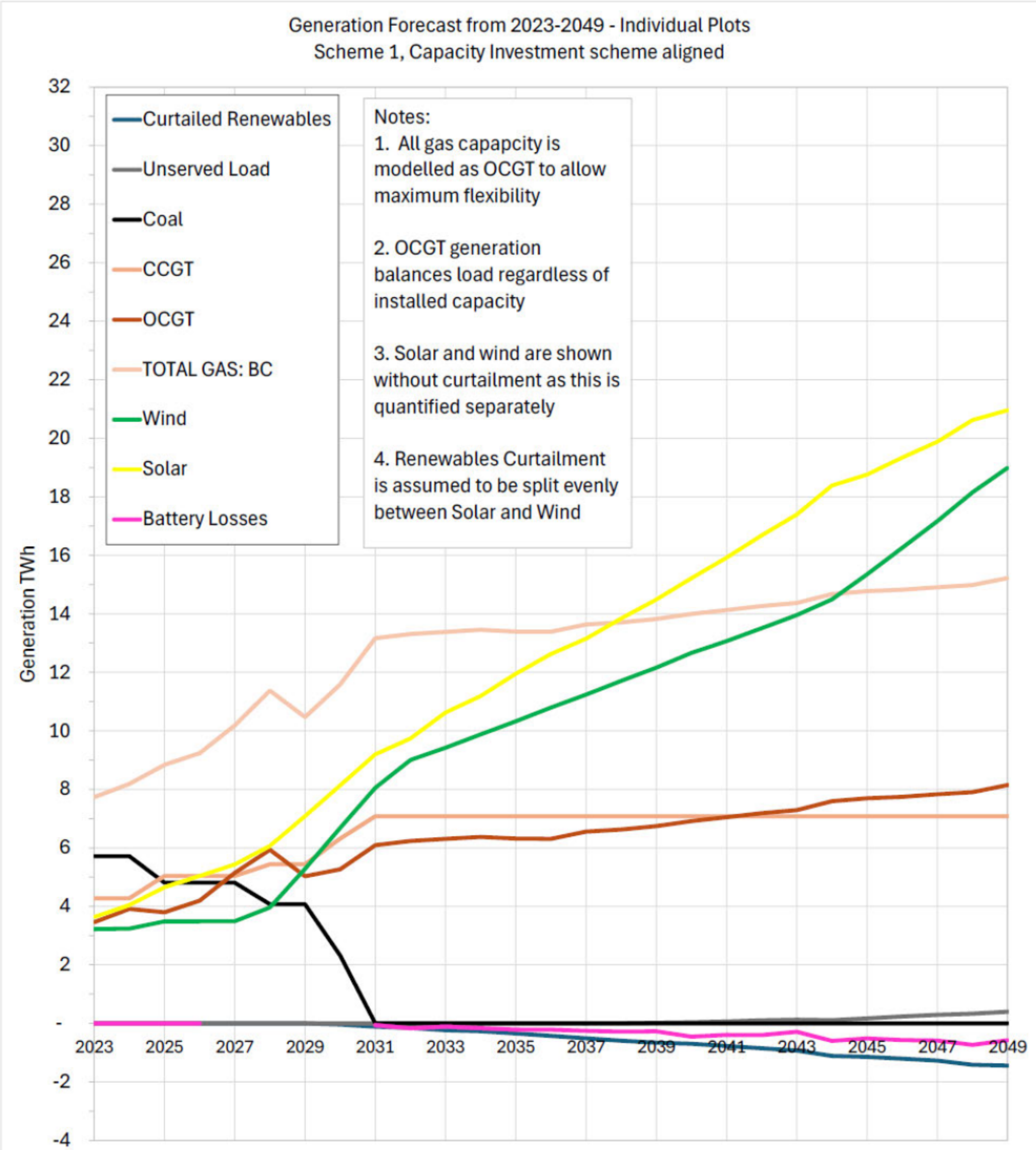


Figure 16: Scheme 1 - Individual generation profiles

Insights from Scheme 1

- GPG as a percentage of total generation increases slightly to ~40% between now and 2030 and declines to ~30% by 2049. Renewables and storage barely cover the load growth between now and 2030 leaving gas to replace the retired coal. Renewables deployment only marginally exceeds load growth out to 2049 having limited impact on gas generation demand which continues to rise gradually from ~12 TWh in 2030 to ~15 TWh in 2049.
- Increasing renewable generation capacity and storage barely keeps pace with increasing load in the September to January period. However, renewables capacity falls far short of meeting the load in the winter months with peak average demand in June of 2049 of ~800 TJ/d equivalent to all existing gas capacity operating at 100% throughout the entire month.

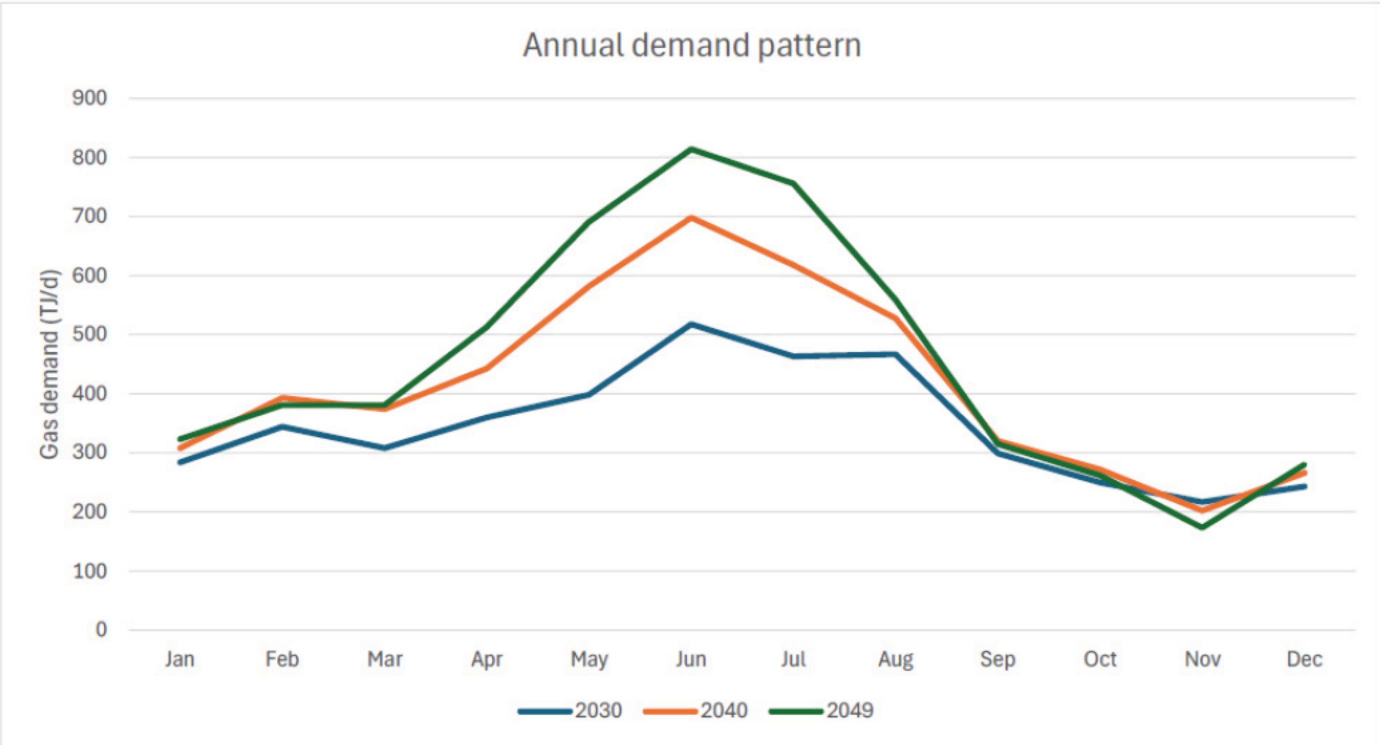


Figure 17: Scheme 1 - Annual pattern of gas demand development over time

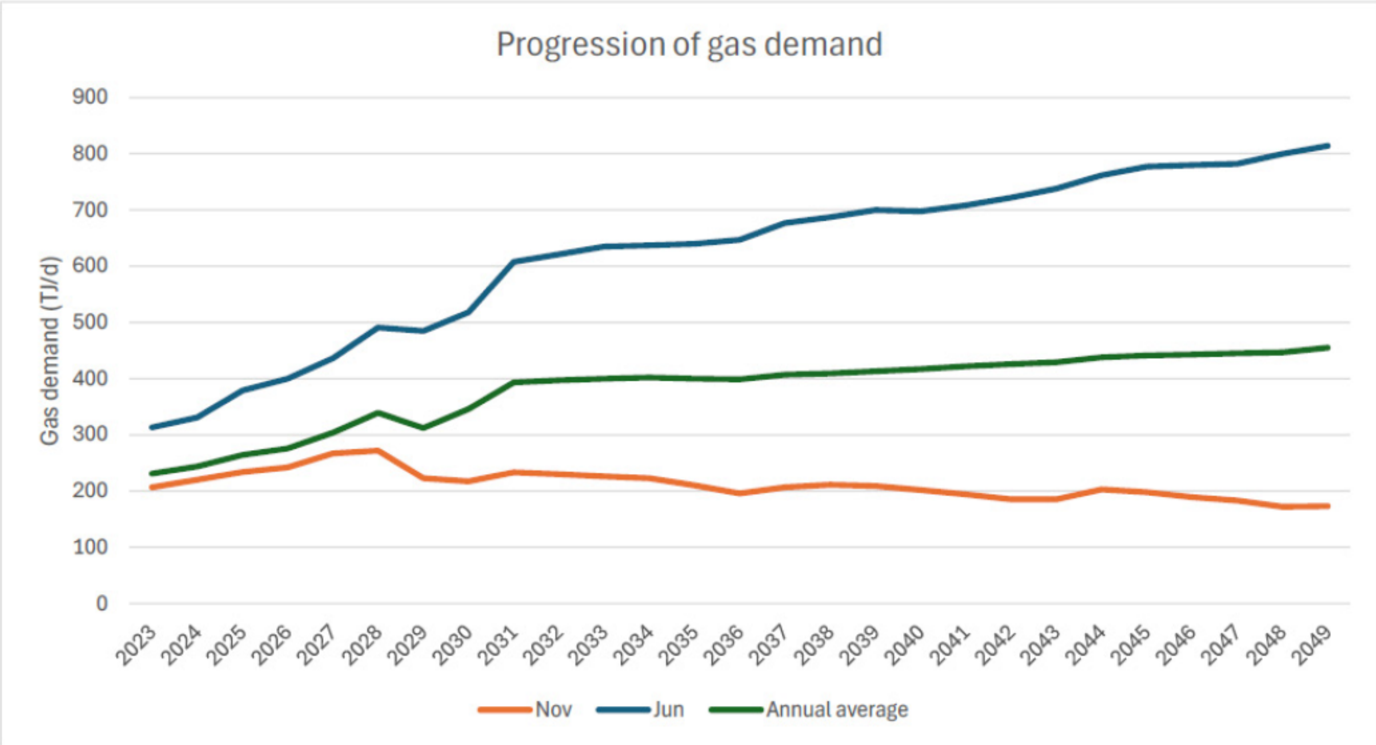


Figure 18: Scheme 1 - Annual pattern of gas demand development over time

- Existing installed gas capacity of ~3,100 MW is required to operate at 100% for periods from 2027 onwards. Peak gas demand using 100% of installed capacity is ~800 TJ/d. Given the grid currently requires spinning reserve of ~250 MW in periods of peak demand the shortfall in gas capacity has significant implications for grid reliability from 2027 onwards. This situation becomes progressively worse as load growth continues to outstrip renewables capacity addition.
- Annual average gas demand for power generation increases from ~230 TJ/d in 2023 to ~460 TJ/d in 2049 equivalent to an increase in average power generation from ~900 MW to 1,800 MW

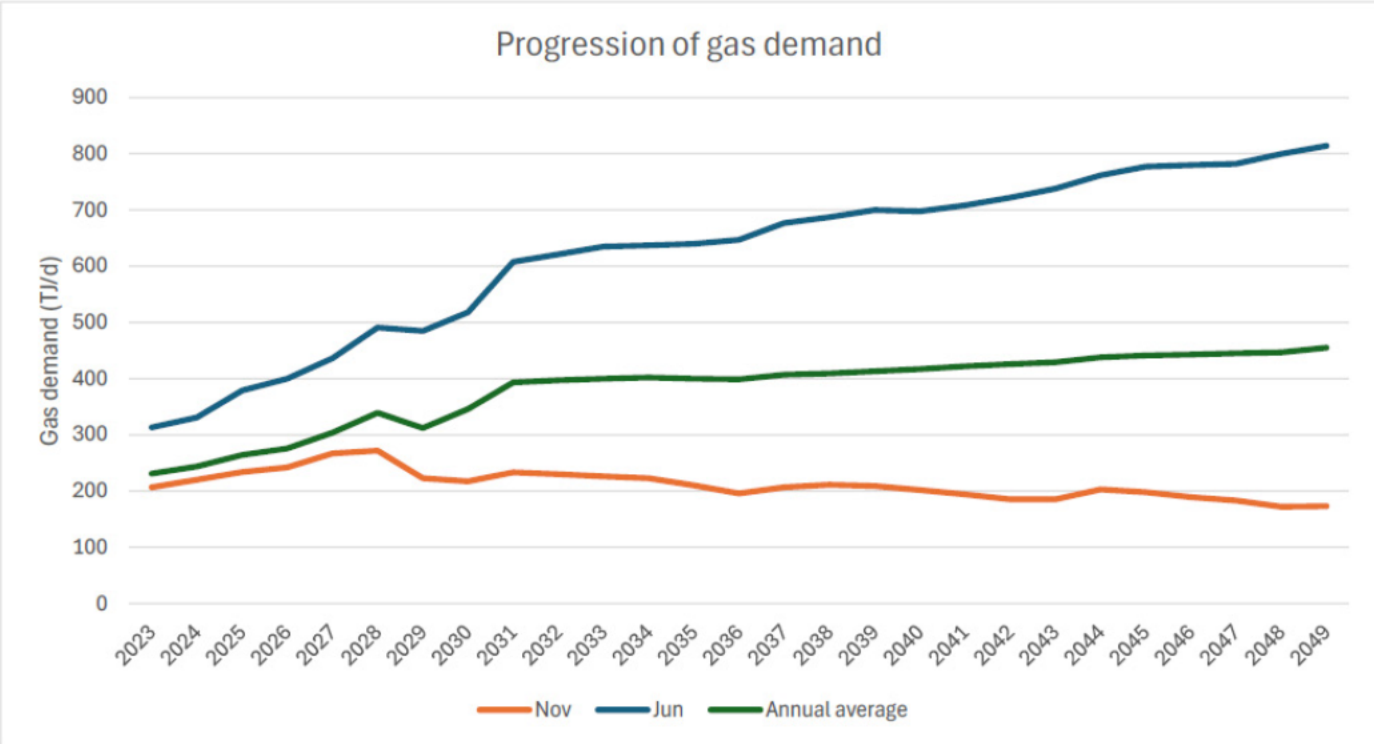


Figure 19: Scheme 1 - Five day peak gas demand profile in 2030

- Beyond 2034 there are periods of unserved load where available generation capacity and storage is insufficient to meet demand at certain times. Although the quantities remain small from a perspective of overall annual energy supplied, i.e. ~0.7% in 2049, this has very significant implications for grid stability and reliability with installed generation capacity unable to supply the load on multiple occasions throughout most months of the year. This would require daily demand response throughout most of the winter.

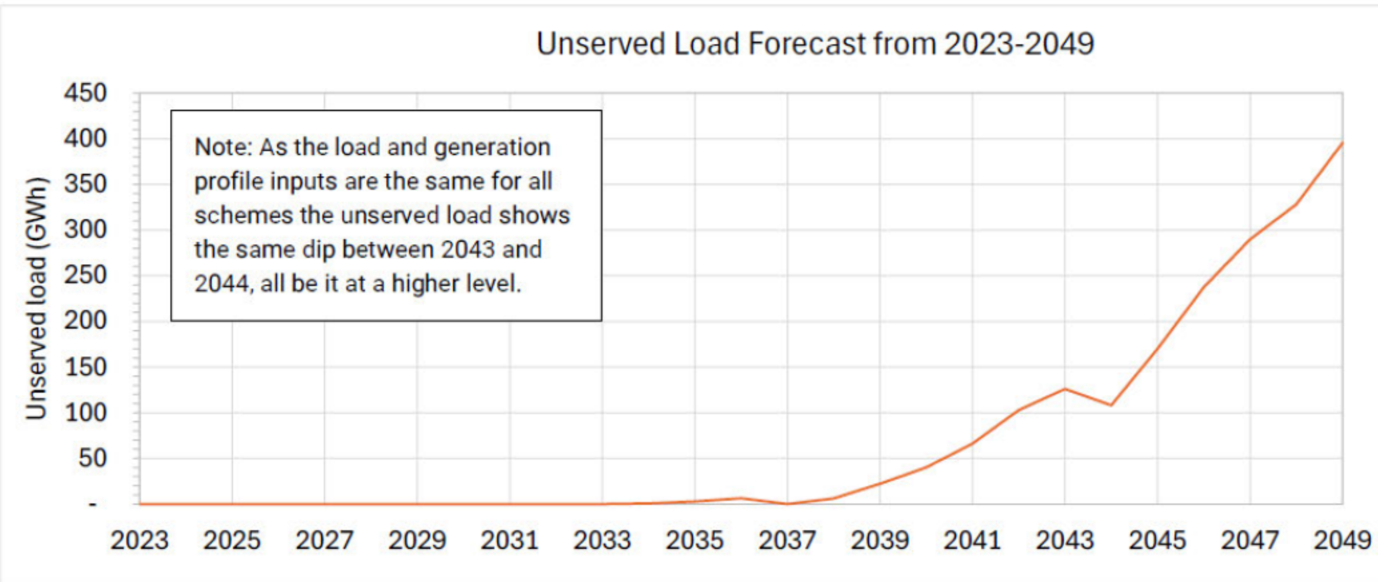


Figure 20: Scheme 1 - Unserved load forecast

- Peak required GPG capacity increases significantly over time. By 2049 the maximum instantaneous demand for GPG is >6400 MW with an associated maximum gas demand of 1,680 TJ/d for a one hour period and 1540 TJ/d for a three hour period.

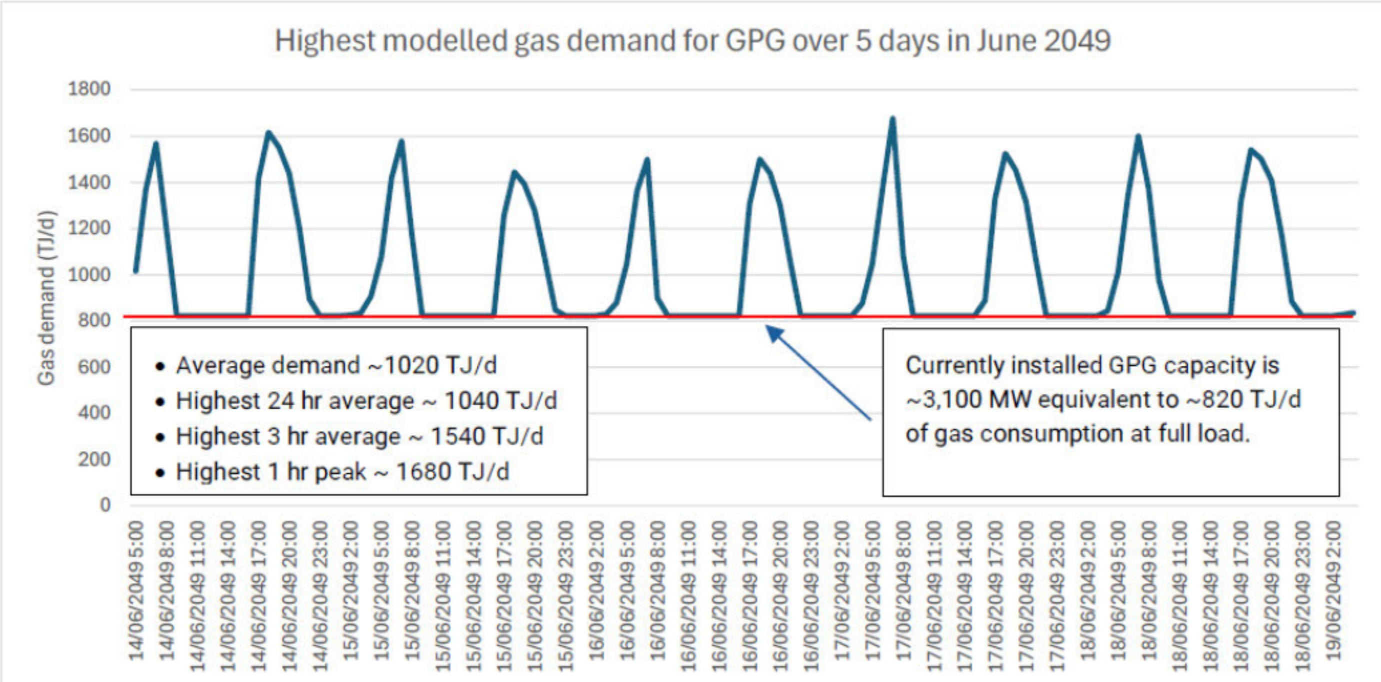


Figure 21: Scheme 1 - Five day peak gas demand profile in 2049

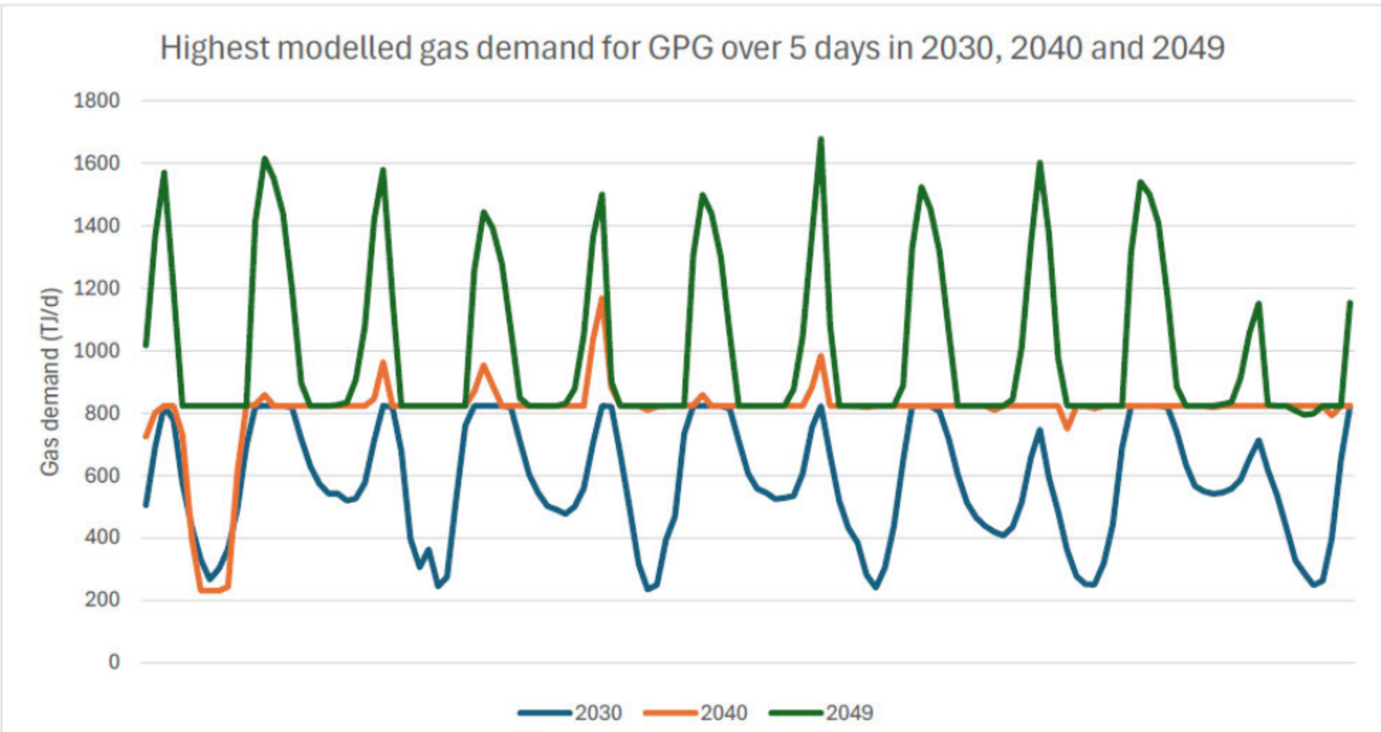


Figure 22: Scheme 1 - Five day peak gas demand profile in 2030, 2040 and 2049

- Renewables start to be curtailed from 2029 but by 2049 the annual curtailment is only ~4% equating to ~1.4 TWh. This is notably lower than either Scheme 2 or Scheme 3 due to the lower level of renewables penetration limiting the seasonal curtailment impact.

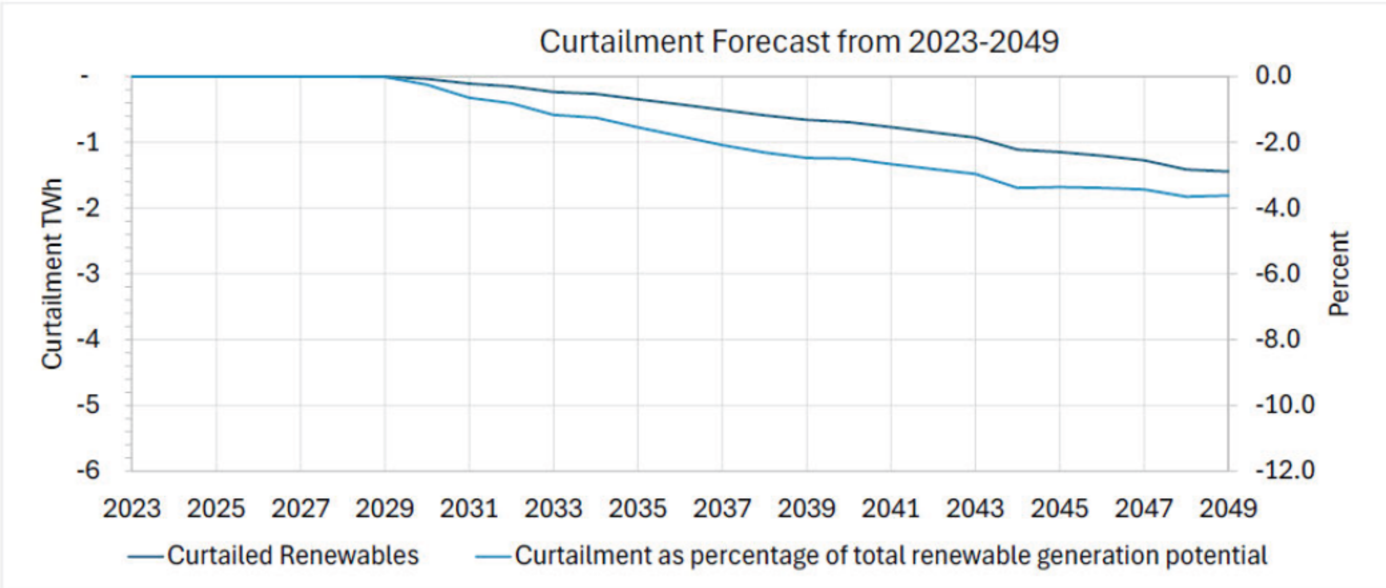


Figure 23: Scheme 1 - Progression of renewables curtailment, absolute and percentage terms.

- Battery round trip losses in 2049 equate to ~0.6 TWh or 1.1% of total load implying battery charging energy flow of ~4 TWh equivalent to 7% of total annual load.

Scheme 2

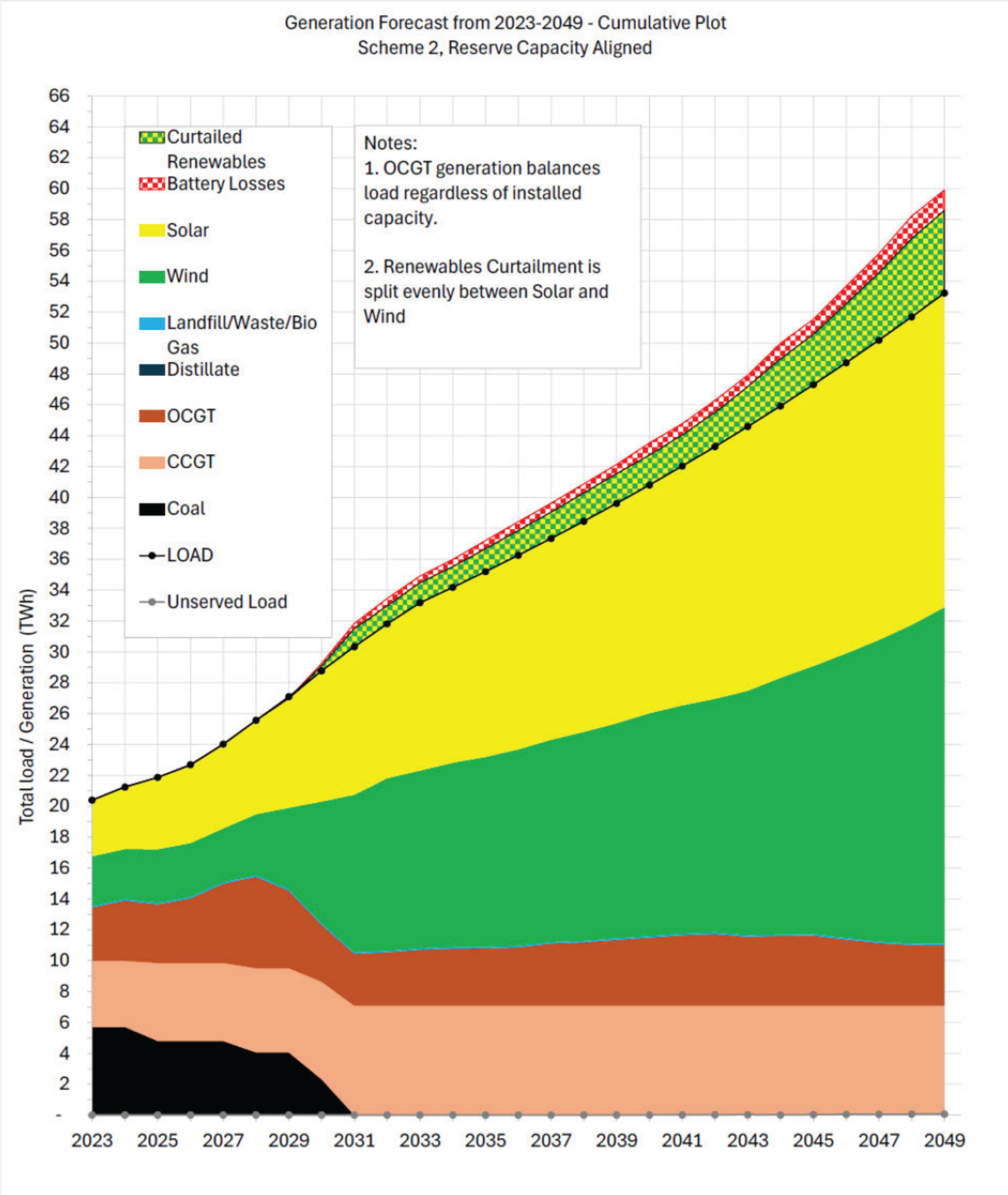


Figure 24: Scheme 2 - Cumulative generation profiles

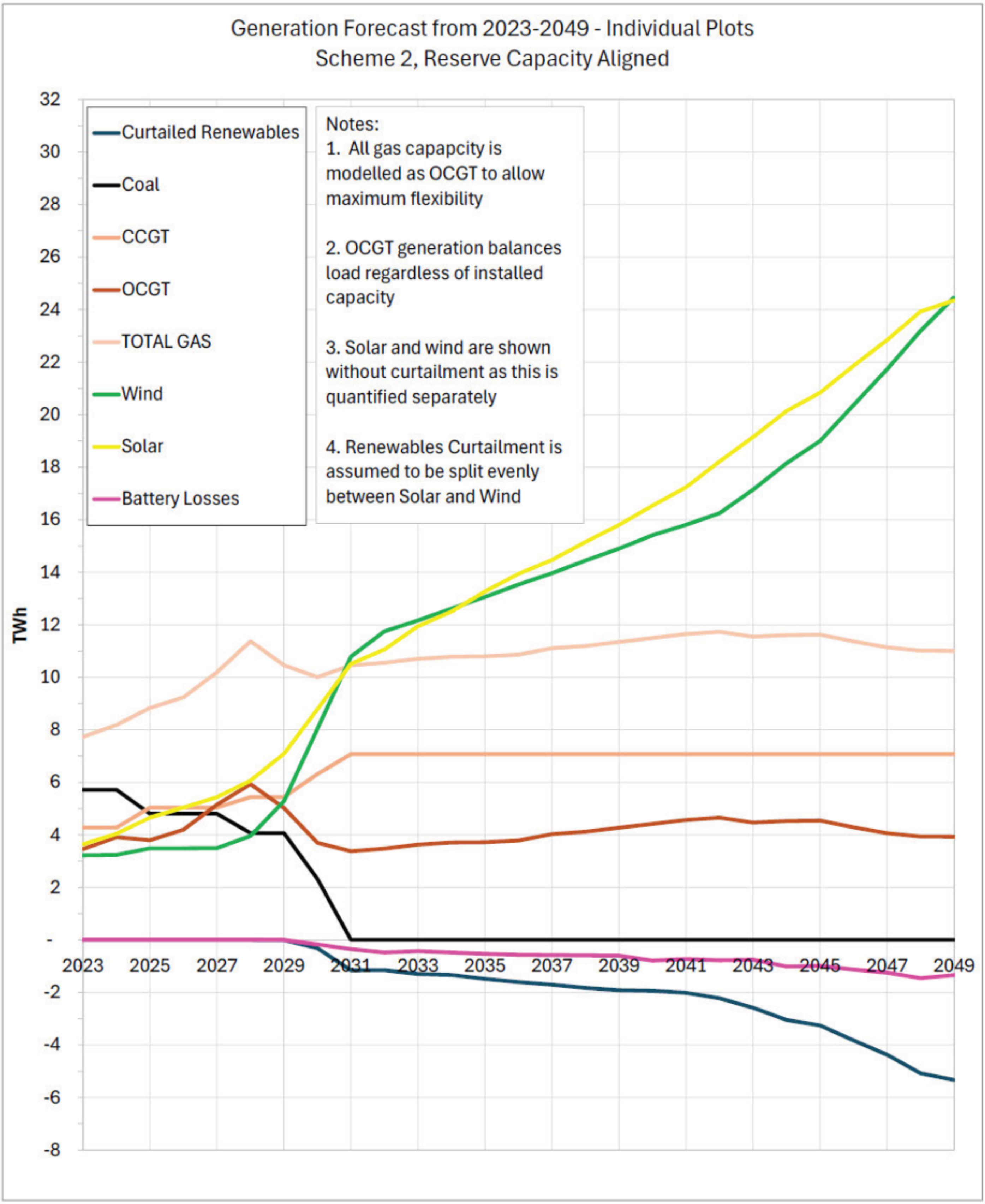


Figure 25: Scheme 2 - Individual generation profiles

Insights from Scheme 2

- GPG as a percentage of total generation gradually declines from ~35% in 2030 to ~20% in 2049. This is driven by renewables and storage picking up the load growth with GPG contributing 10-12 TWh of generation annually throughout the period.
- Increasing renewable generation capacity and storage keeps pace with increasing load in the September to April period. However, the impact of seasonal variation in renewable output becomes more accentuated with higher levels of renewables in the grid, requiring proportionately more gas firming to meet the load in winter. Peak average demand in 2049 of ~610 TJ/d is in June with minimum average demand of ~160 TJ/d in November.

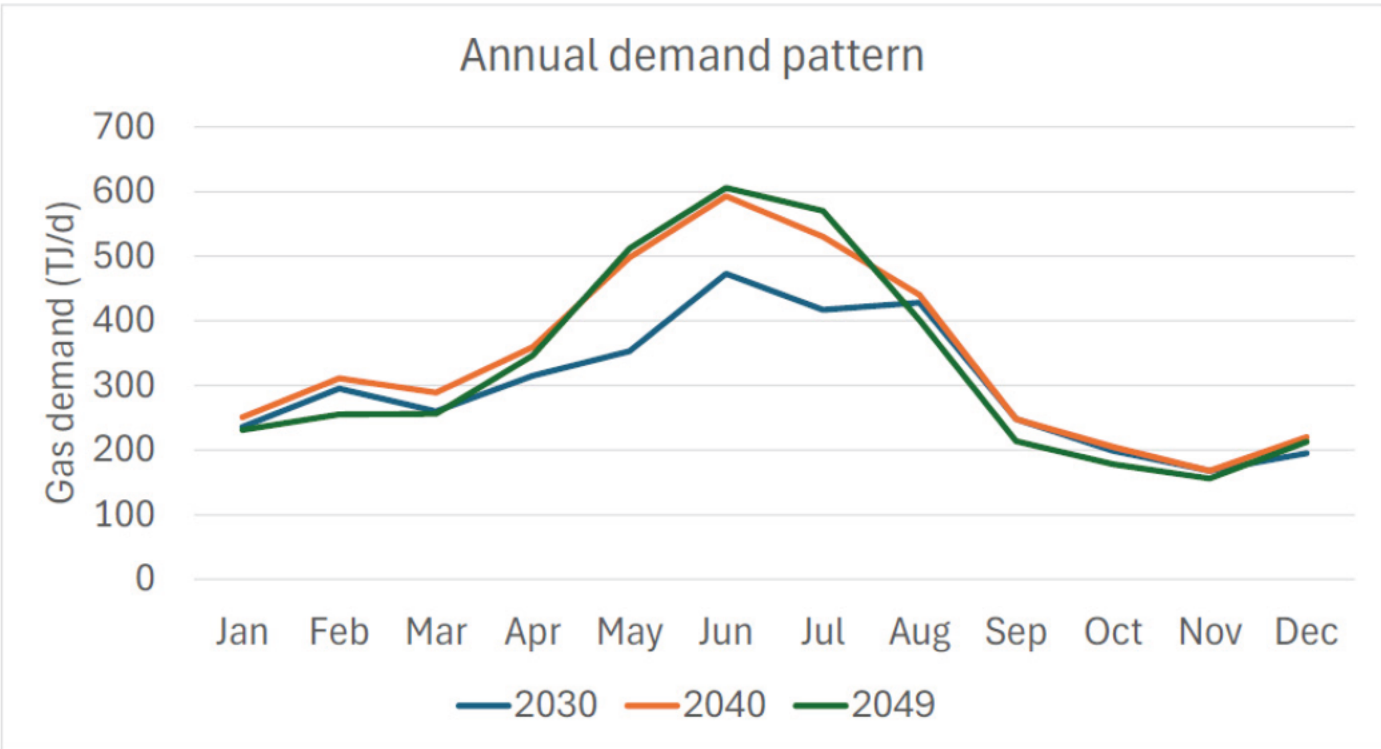


Figure 26: Scheme 2 - Annual pattern of gas demand development over time

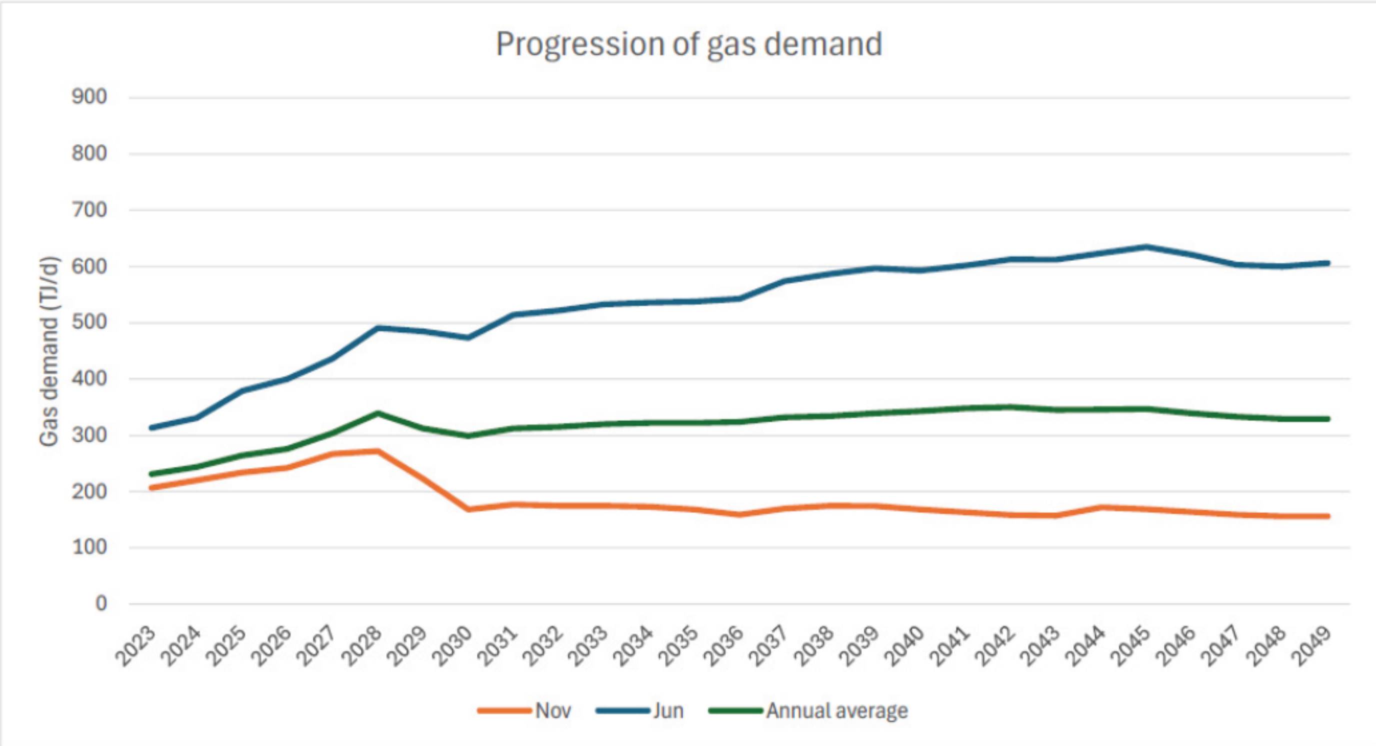


Figure 27: Scheme 2 - Annual pattern of gas demand development over time

- Existing installed gas capacity of ~3,100 MW is required to operate at 100% for periods from 2027 onwards. Peak gas demand at 100% capacity is ~820 TJ/d. Given the grid currently requires spinning reserve of ~250 MW in periods of peak demand the shortfall in gas capacity may impact grid reliability from 2027 requiring demand response measures to be used.
- Annual average gas demand for power generation increases from ~230 TJ/d (~880 MW) in 2023 to ~330 TJ/d (~1,300 MW) in 2049.

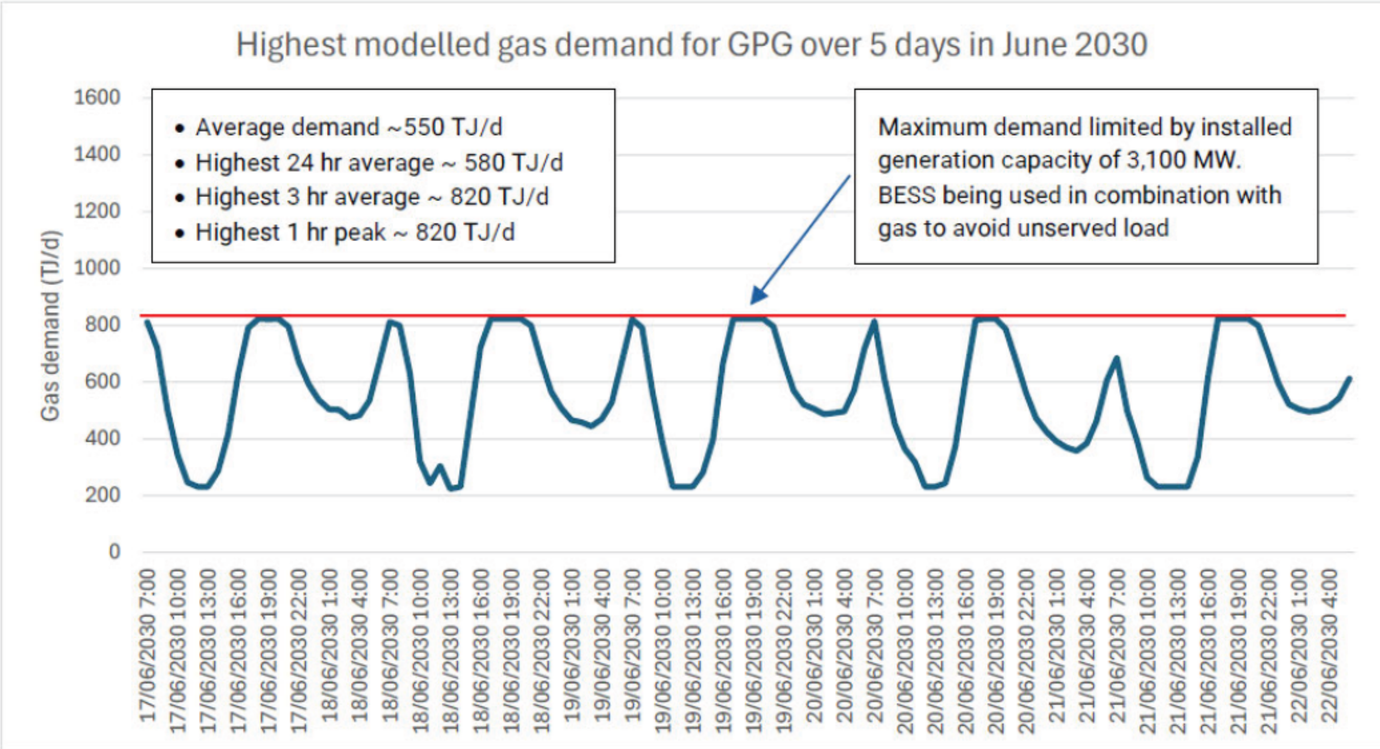


Figure 28: Scheme 2 - Five day peak gas demand profile in 2030

- Beyond 2039 there are periods of unserved load where available generation capacity and storage is insufficient to meet demand at certain times. Although the quantities are minimal from a perspective of overall annual energy supplied, i.e. ~0.1% in 2049, this has implications for grid stability and reliability with the installed generation capacity being unable to supply the peak load on multiple occasions.

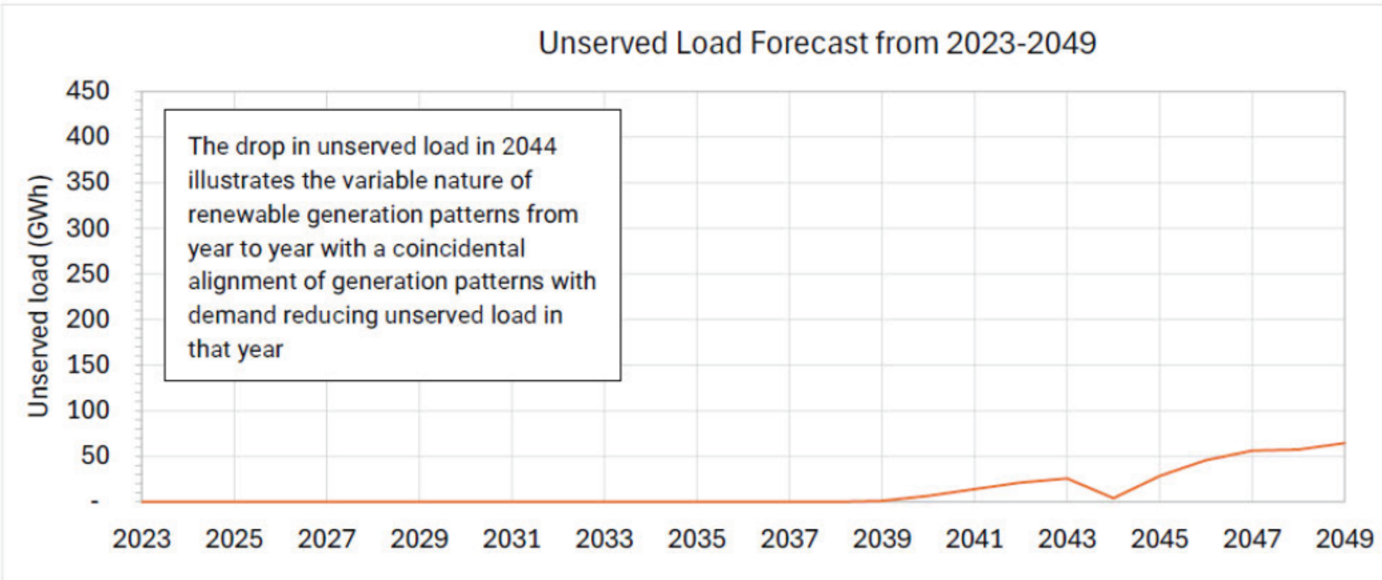


Figure 29: Scheme 2 - Unserved load forecast

- Peak required GPG capacity increases progressively over time. By 2049 the maximum instantaneous demand for GPG is ~5,400 MW with an associated maximum gas demand of 1,410 TJ/d for a one hour period and 1290 TJ/d for a three hour period.

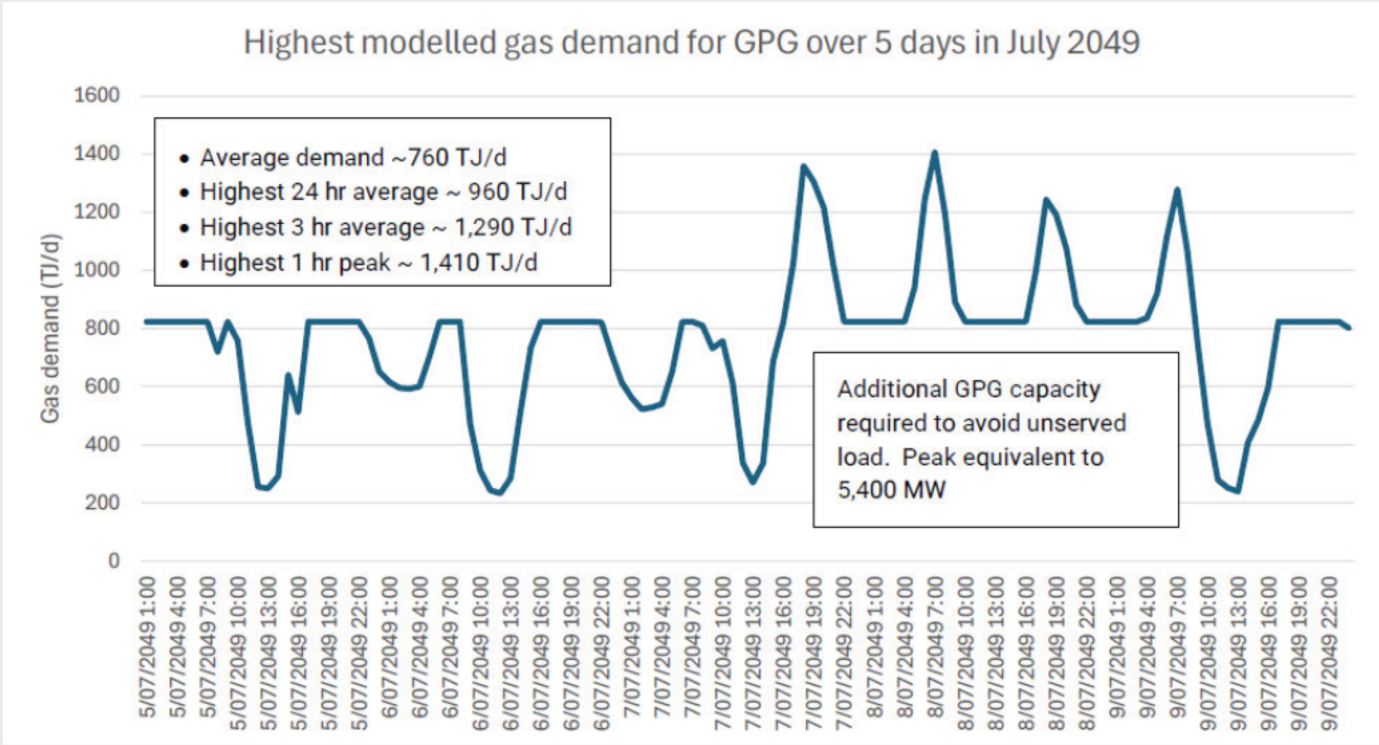


Figure 30: Scheme 2 - Five day peak gas demand profile in 2049

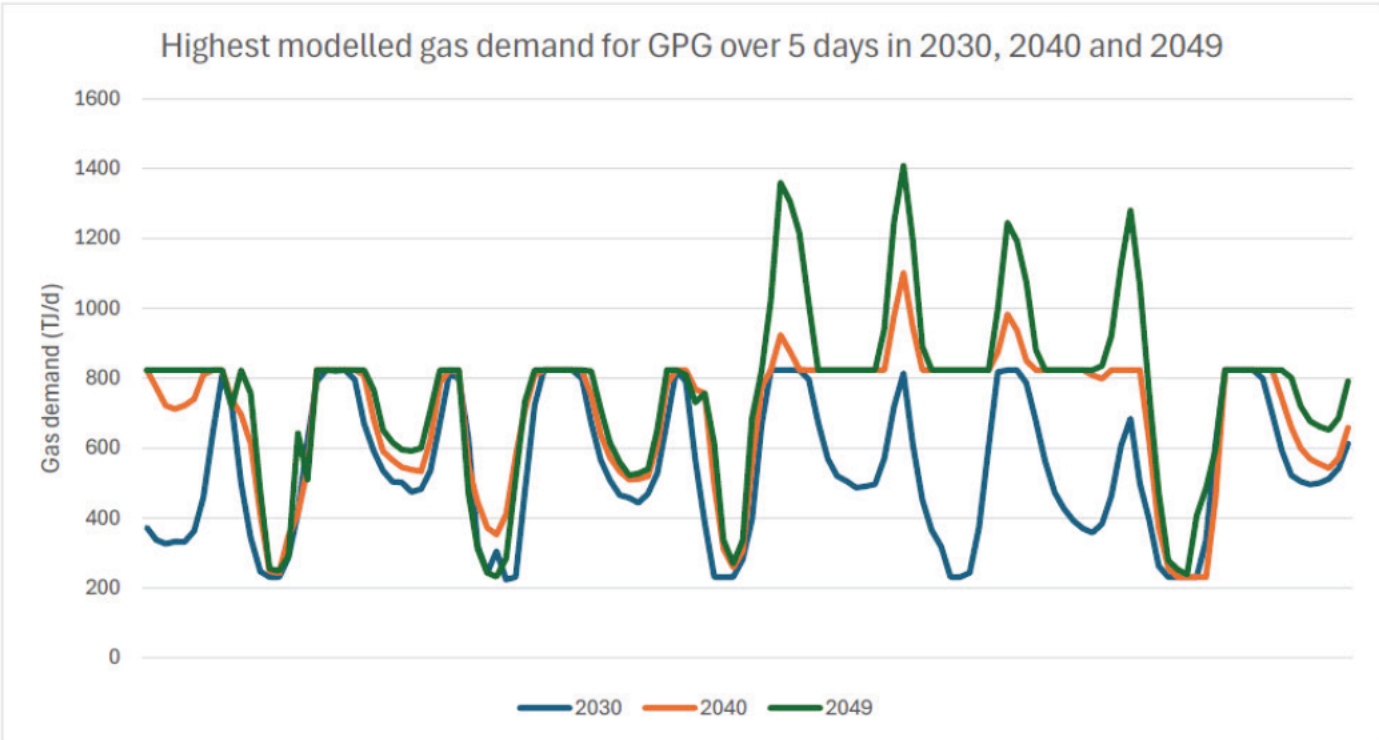


Figure 31: Scheme 2 - Five day peak gas demand profile in 2030, 2040 and 2049

- Renewables start to be curtailed from 2029 and by 2049 the annual curtailment is ~11% equating to 5.3 TWh. The significance of this is that incremental renewables need to be cost competitive at increasingly high levels of curtailment requiring lower unit capital costs to be commercially viable. Whilst it is anticipated renewable costs will continue to decline, this is essential for renewables to be competitive with gas for electrification of industrial heat. 1 MW of electricity is equivalent to ~4 GJ of gas which currently costs around AU$25-35 delivered. Curtailment of renewables will make this more challenging.

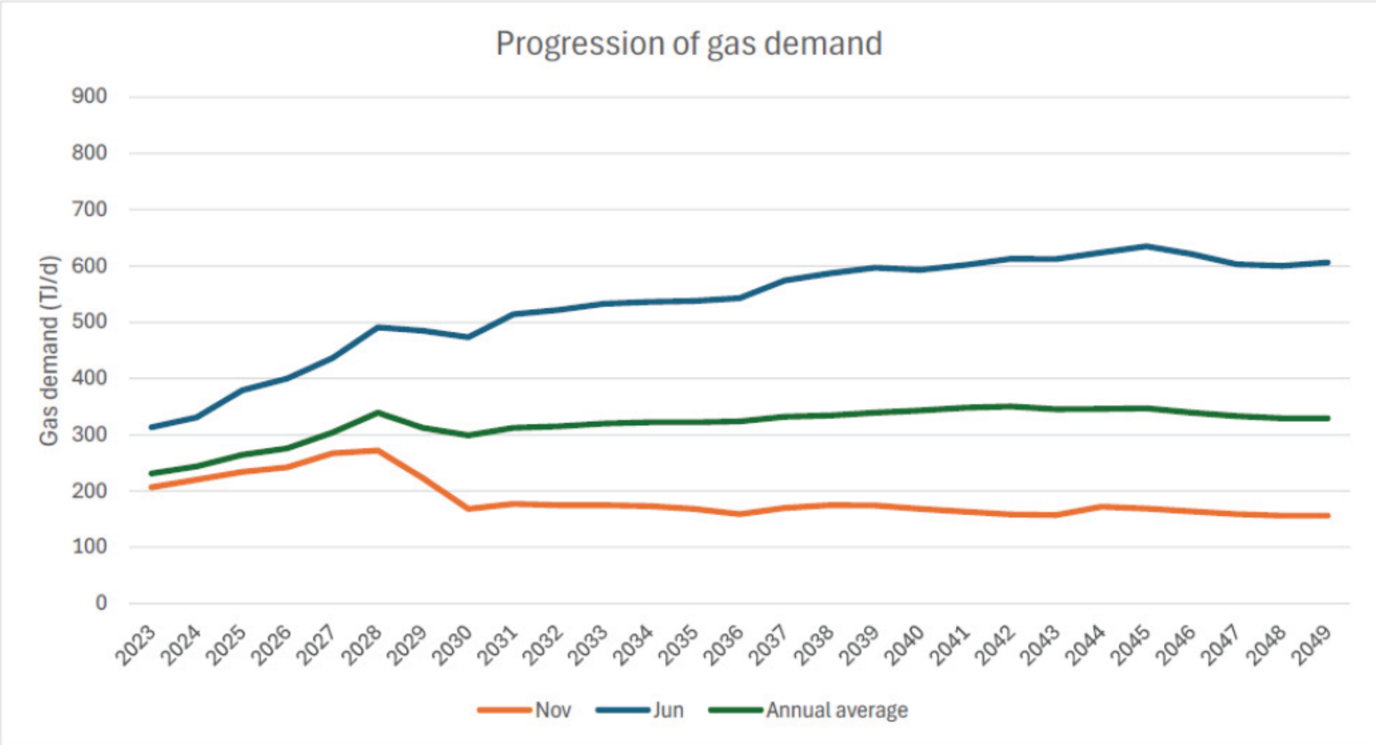


Figure 32: Scheme 2 - Progression of renewables curtailment, absolute and percentage terms

- Battery round trip losses in 2049 equate to ~1.3 TWh or 2.4% of total load implying battery charging energy flow of ~9 TWh equivalent to 16% of total annual load.

Scheme 3

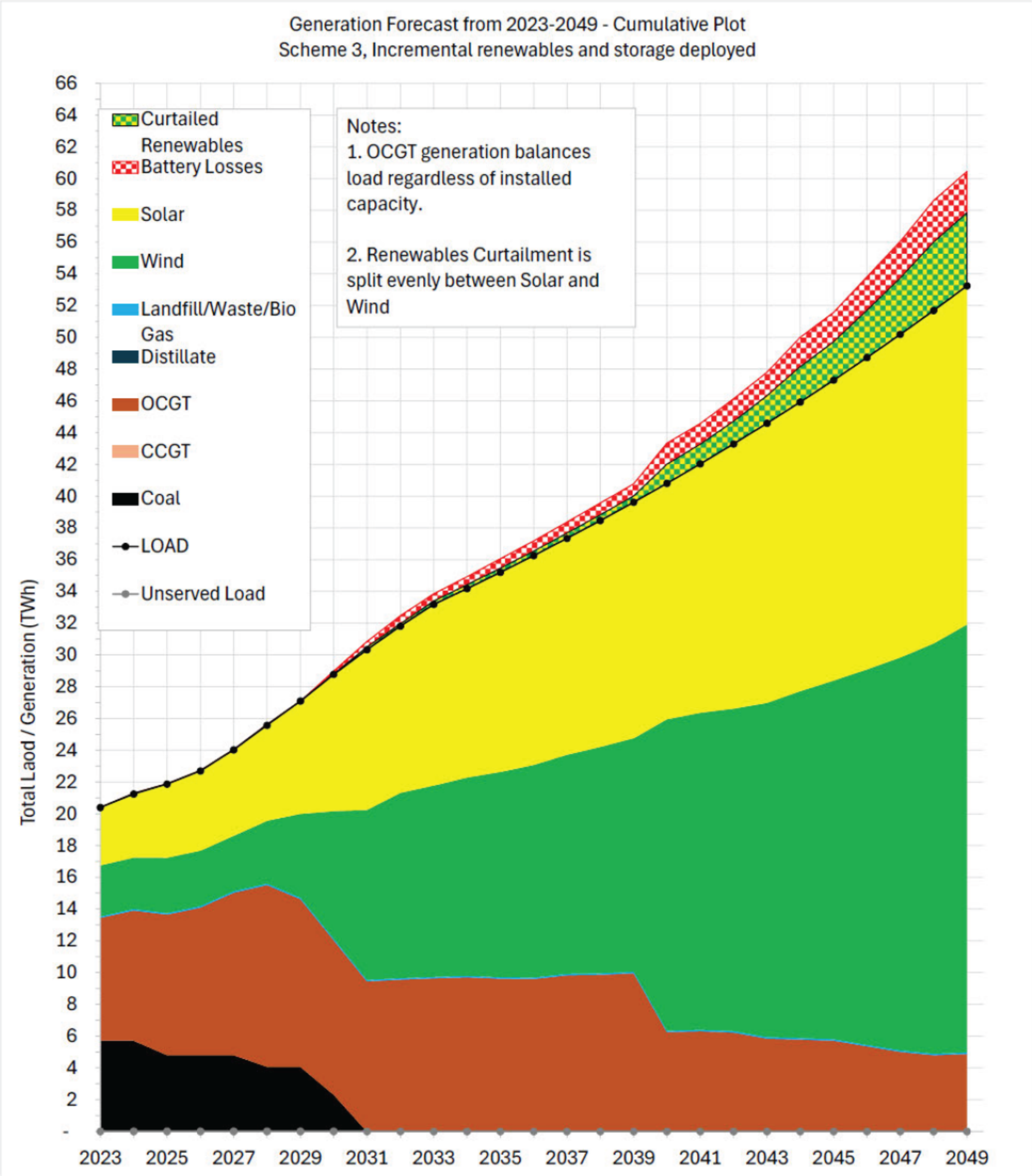


Figure 33: Scheme 3 – Cumulative generation profiles

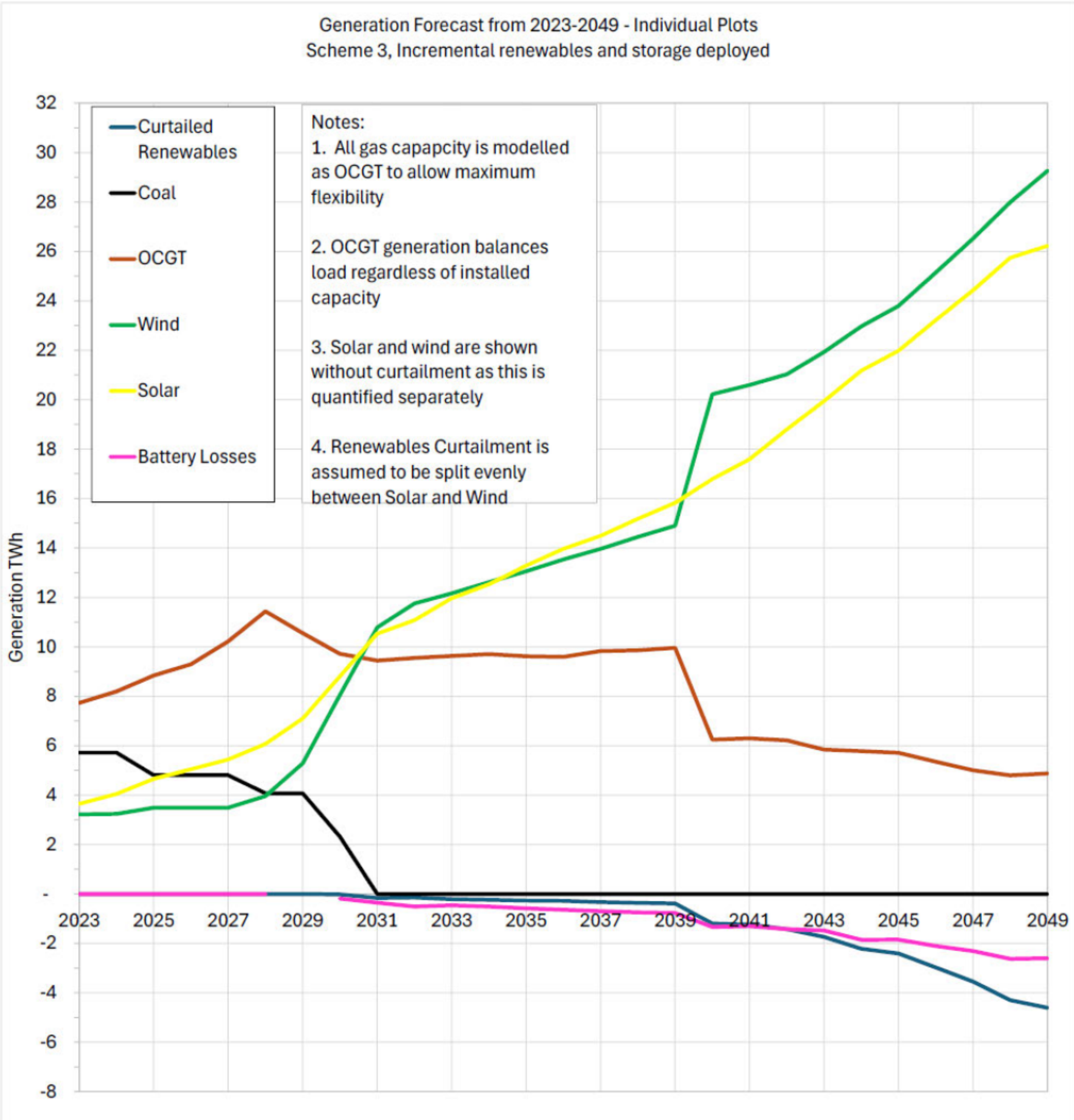


Figure 34: Scheme 3 - Individual generation profiles

Insights from Scheme 3

- GPG as a percentage of total generation declines from ~35% in 2030 to ~10% in 2049 with a large step down in 2040 due to the addition of 1 GW of offshore wind coupled with >6 GWh of storage. Renewables and storage pick up all of the load growth and progressively back out GPG which declines from ~10 TWh in 2030 to ~5 TWh in 2049.
- Increasing renewable generation capacity significantly outpaces increasing load in the September to April period, ultimately resulting in zero gas generation demand from September to January and minimal demand in Feb and March of 2049. However, significant levels of gas firming are still required during the winter months when renewables output is lower with a peak of ~450 TJ/d in June.

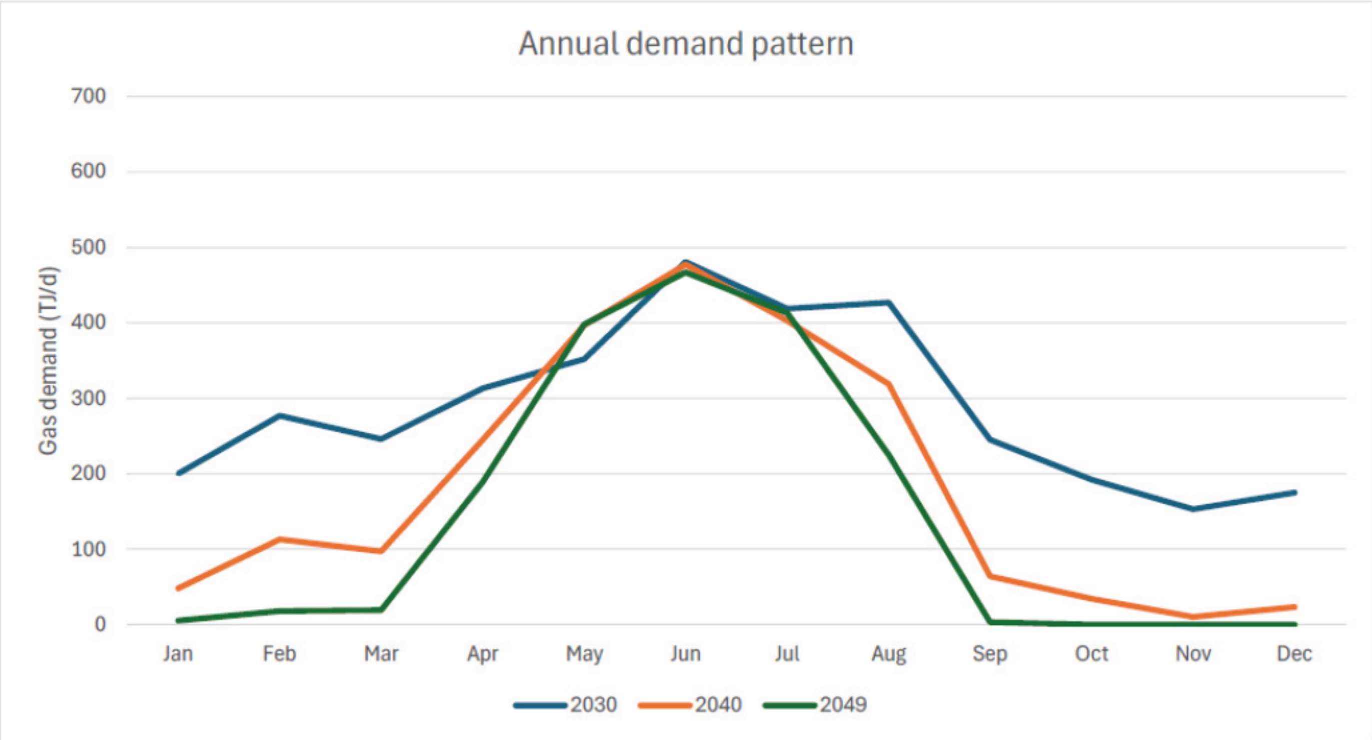


Figure 35: Scheme 3 - Annual pattern of gas demand development over time

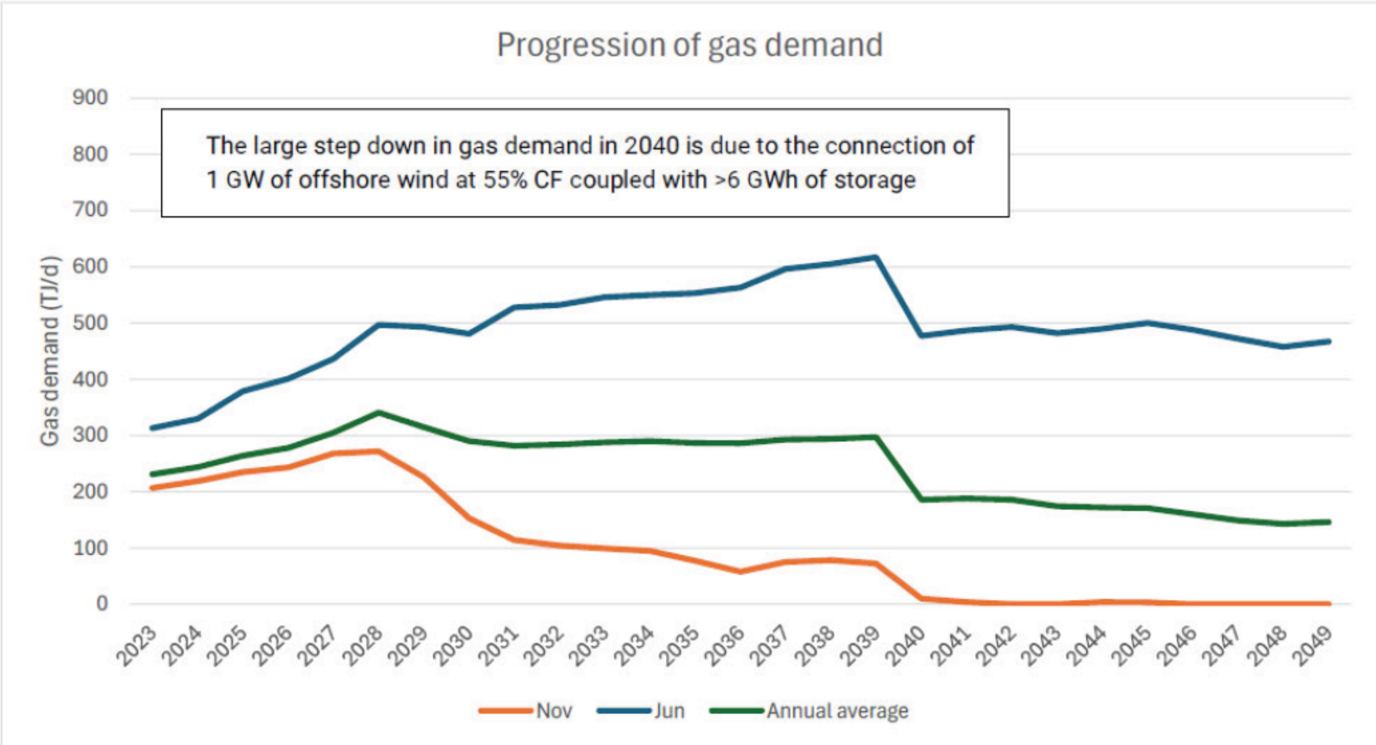


Figure 36: Scheme 3 - Annual pattern of gas demand development over time

- Existing installed gas capacity of ~3,100 MW is required to operate at 100% for periods from 2028 onwards. Peak instantaneous gas demand at 100% capacity is ~820 TJ/d. However, in this scheme the ability of existing installed GPG capacity to meet demand is not materially exceeded, even in 2049 and as a result there are no cases of unserved load.
- Annual average gas demand for power generation peaks at ~340 TJ/d (1,300 MW) in 2028 before declining to ~150 TJ/d (~570 MW) in 2049 with a significant step down in 2040 due to the assumed connection of 1 GW off offshore wind.

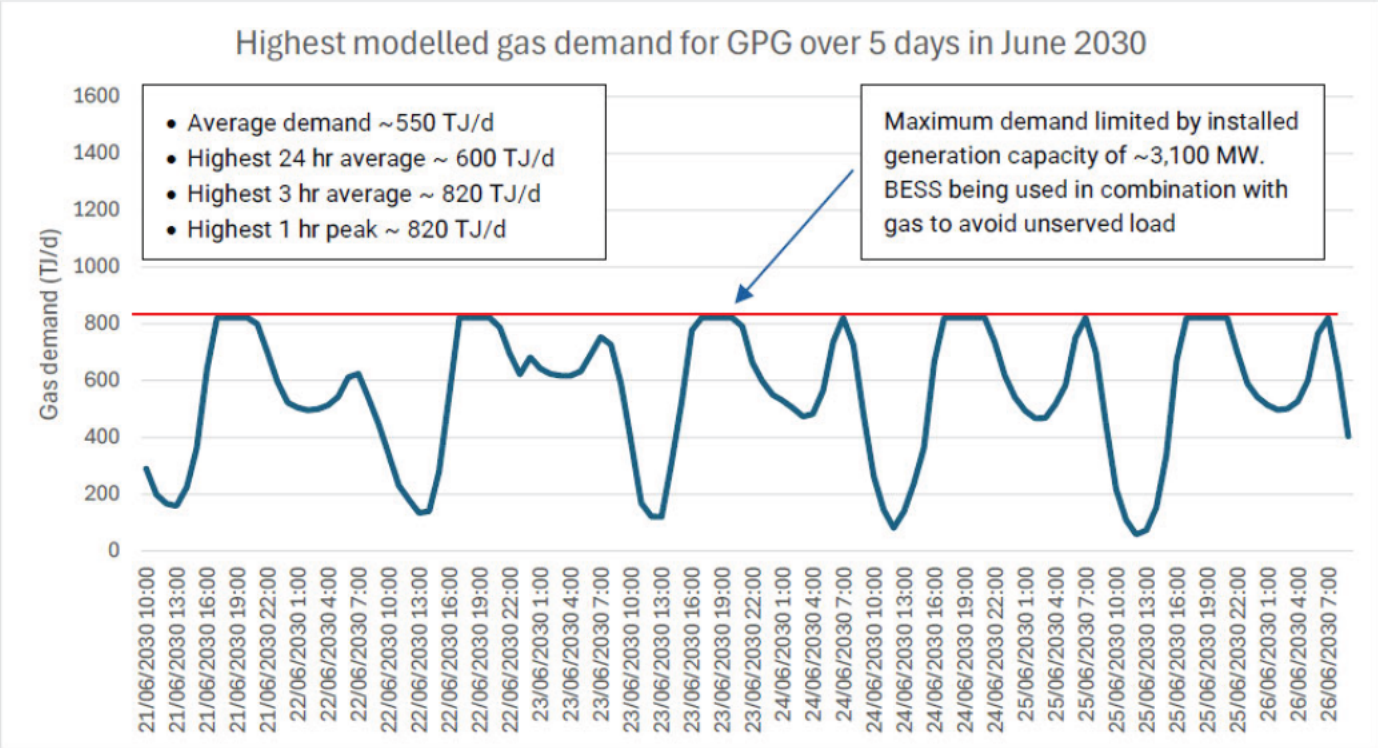


Figure 37: Scheme 3 - Five day peak gas demand profile in 2030

- Peak required GPG capacity does not increase over time and average demand only increases marginally due to the addition of renewables and storage capacity almost matching the winter load. Also, allowing the model 100% flexibility to optimise gas with no assumed CCGT baseload results in brief periods of zero GPG demand, even in the winter months.

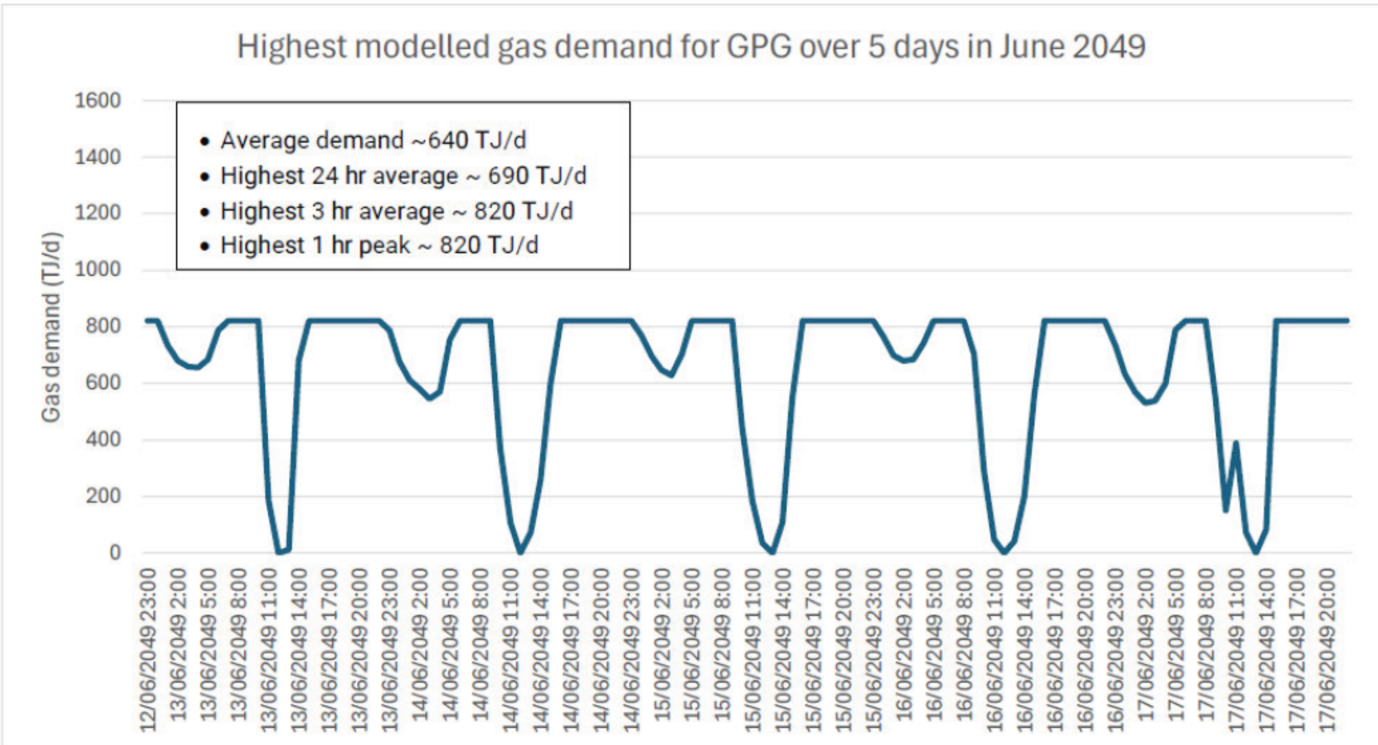


Figure 38: Scheme 3 - Five day peak gas demand profile in 2049

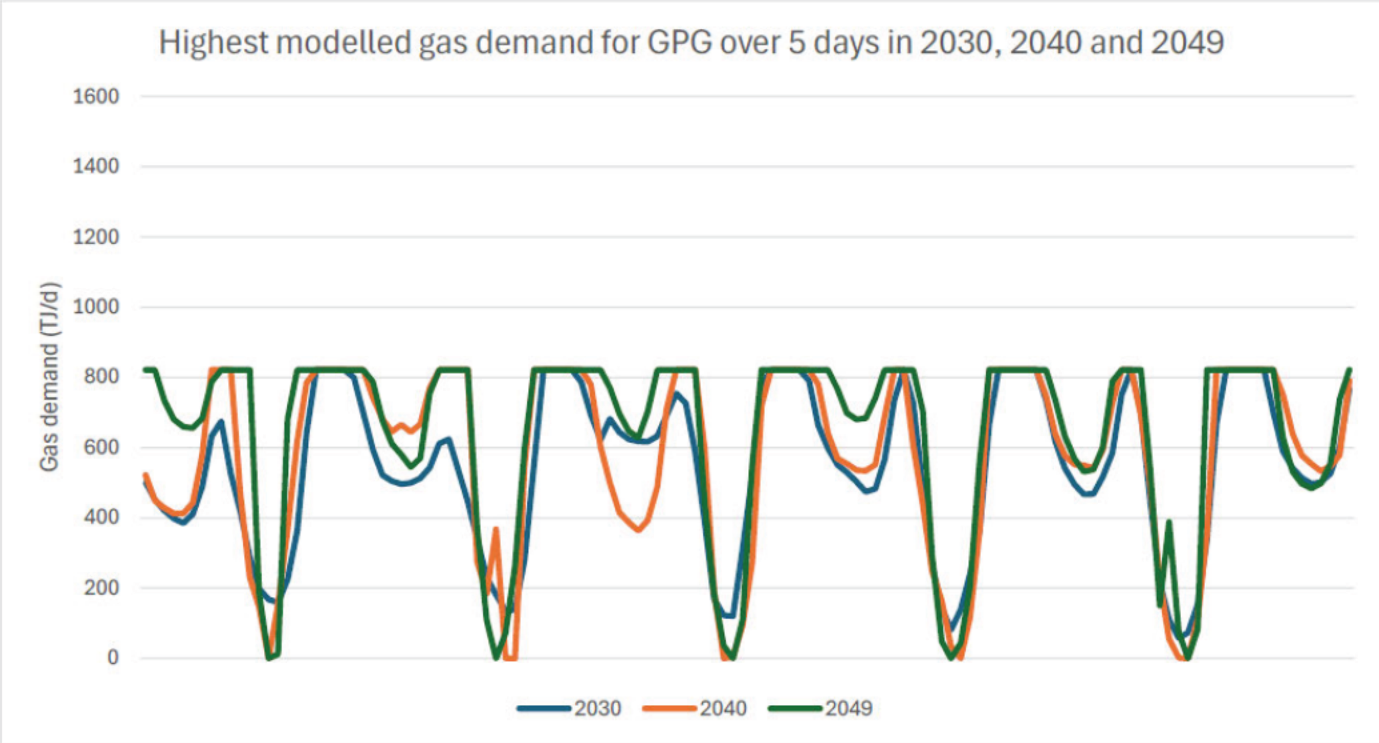


Figure 39: Scheme 3 - Five day peak gas demand profile in 2030, 2040 and 2049

- Renewables start to be curtailed from 2029 and by 2049 the annual curtailment is ~8% equating to 4.6 TWh. This is a notably lower curtailment percentage than scheme 1 in spite of a higher penetration of renewables due to the very high level of storage capacity that is assumed. This is reflected in the increased battery losses associated with this scheme showing the increased use of storage – See below.

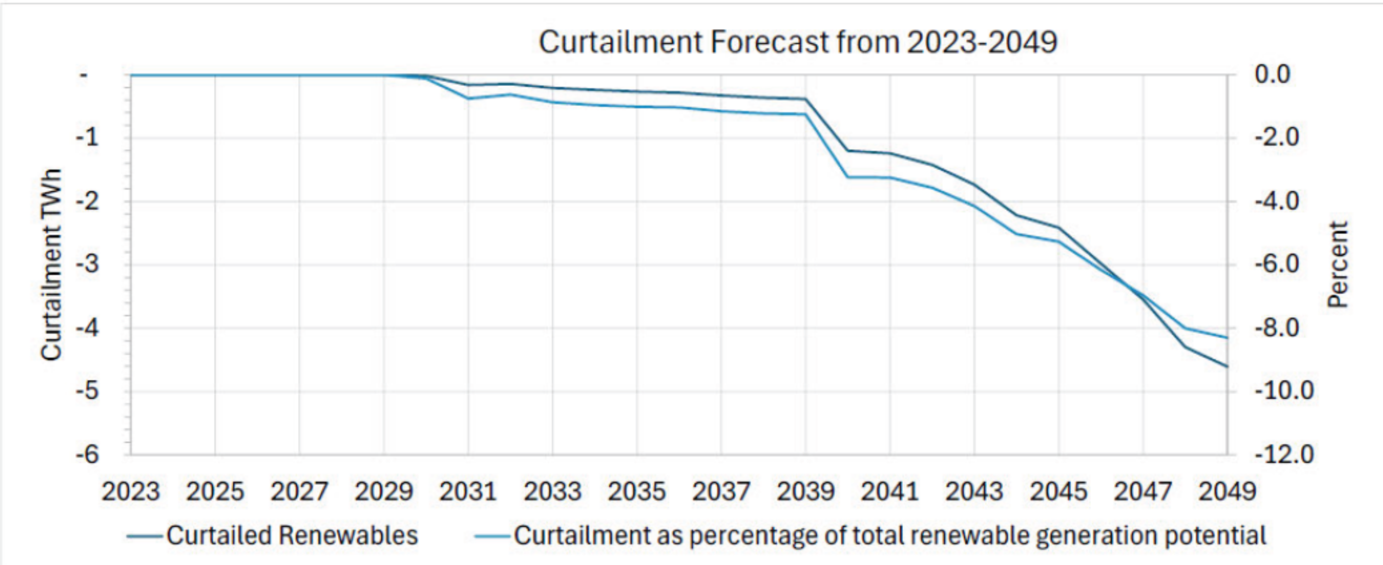
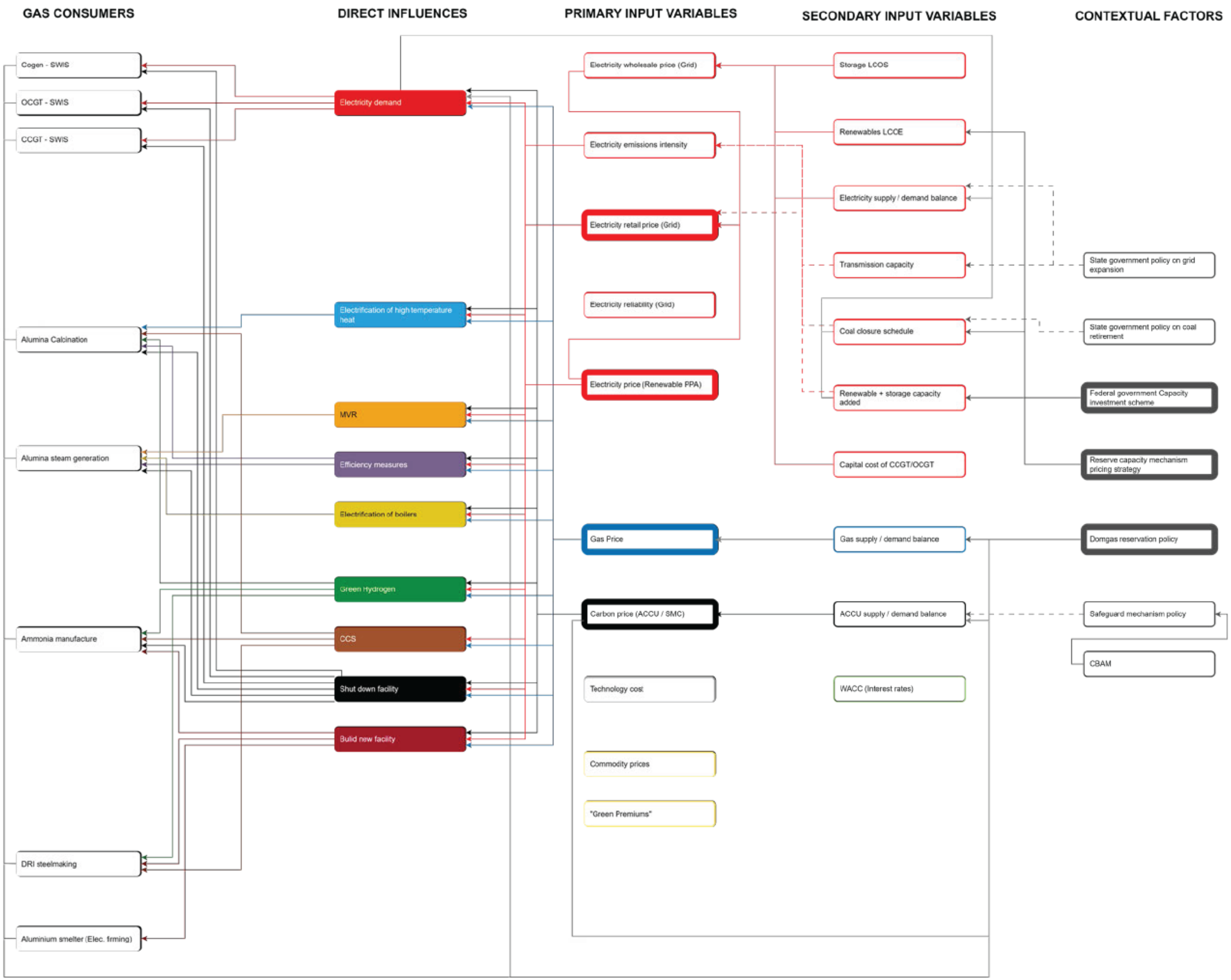


Figure 40: Scheme 3 - Progression of renewables curtailment, absolute and percentage terms.

- Battery round trip losses in 2049 equate to ~2.6 TWh or 4.9% of total load implying battery charging energy flow of ~17 TWh equivalent to 33% of total load.

Appendix 1 – Direct influences, Variables and Contextual Factors Affecting Gas Demand

Figure 41 Diagram of existing and potential gas consumers together with influencing factors and related contextual factors considered



Our approach to modelling included the following steps which are illustrated in the graphic opposite.

2. Identify influencing factors

For those current and potential future shippers responsible for the majority of AGIG's revenue, identify direct influencing factors, technologies and decisions likely to impact their gas consumption and contracting strategy over time, e.g., deployment of Mechanical Vapour Recompression is a key factor in future decarbonisation of alumina.

The most relevant direct influences identified are listed in the column immediately to the right of the gas consumers and include; changes in grid electricity demand, various decarbonisation technologies, and construction of new facilities that might consume gas.

3. Identify input variables

For each direct influence, identify the main input variables and other key conditions which will contribute to whether that influence should be active in the model, e.g., gas price is a key variable that will influence the commercial viability of every technology targeted at replacing gas with something else.

The columns of primary and secondary input variables are a non-exhaustive list of the factors considered likely to have a material impact on the direct influences of gas consumption.

Clearly all of the input variables have some part to play and there are many interactions and feedback loops which have been considered with the primary ones illustrated here. Not all relationships have been mapped to avoid cluttering the diagram any further.

As previously noted, a model incorporating all these variables and feedback loops would be unwieldy and unnecessarily complex, as eventually all input variables translate into a handful of costs which ultimately determine commercial decisions.

Those Input Variables highlighted with a bold outline are considered to be the most fundamental in influencing any commercial decisions relating to decarbonisation; namely, electricity price, gas price and carbon price, and these are the variables that have been incorporated into the modelling logic.

4. Identify contextual factors

For each of the key input variables identify the contextual factors likely to have a material influence on them and how these factors could affect the input variables over time.

The range of contextual factors that could impact on gas, electricity and carbon prices and hence influence decarbonisation decisions is vast. For the purposes of this exercise we have focused on three very tangible factors highlighted by a bold border, namely:

1. The WA State Government Domgas Reservation Policy;
2. The Federal Government Capacity Investment Scheme and;
3. The AEMO Reserve Capacity Mechanism for the SWIS.

The Domgas Reservation Policy directly influences both the availability and price of gas and also has a weaker indirect influence on the price of electricity.

The CIS will influence the level of renewable energy penetration and storage in the SWIS, which in turn influences availability, emissions intensity, and price of electricity.

The RCM sets a target which, combined with a stated desire to decarbonise the SWIS, should also influence the penetration of renewables and storage in the SWIS.

The potential impact of these contextual factors, including any interactions and feedback loops has been explored through carefully considered internally consistent scenarios. The development of these scenarios and supporting rationale are discussed in more detail in the main body of the report.

Useful metrics and comparative costs

The below metrics and cost equivalencies are helpful when considering the potential decarbonisation pathways of the major gas shippers.

- A $1/GJ variance in gas price is equivalent to ~$20/tCO2-e variance in carbon price and vice versa
- 1 MWh of high temperature electrical resistance heating is equivalent to ~5 GJ of gas, i.e., If gas is $10/GJ electricity must be <$50/MWh to compete
- 1 MWh of electricity used for low temperature (<180C) steam generation through MVR is equivalent to ~10 GJ of gas, i.e., If gas is $10/GJ electricity must be <$100/MWh to compete
- A delivered gas price of $10/GJ is equivalent to a delivered hydrogen price of $1.32/kg on an LHV energy equivalence basis.
- A zero-emissions hydrogen price of $5/kg requires a carbon price of ~$530/tonne to break even with gas at $10/GJ on an LHV energy equivalence basis.
- A $2/kg subsidy on hydrogen is equivalent to ~$290/tonne carbon price when compared with gas on an LHV energy equivalence basis.
- AU$1 billion will buy ~100 MW of green hydrogen manufacturing capacity plus sufficient hybrid renewables to power it with an annual output of ~12 ktpa H2 (The World Bank has a 1, 10, 20, 30 rule stating that 1 mtpa of H2 requires 10 GW of electrolyser capacity supported by 20 GW of renewables capacity and costing US$ 30 billion but Australia is currently more expensive than the world average and we are a little less optimistic about capacity factors) (66)

For a gas price of $10/GJ and emissions factor of 51.53 kgCO2-e/GJ as prescribed by the National Greenhouse Account Factors for stationary combustion the following table summarises likely gas generation costs and emissions intensities. Note that as the SWIS is a capacity market, the capex of a firm generation source is largely covered by Reserve Capacity Payments (67).

Table 16 Gas generation fuel costs and emissions intensitites

Power generation technology	Electricity price based on fuel cost only ($/MWh)	Emissions intensity $kgCO_2$-e/MWh
OCGT	110-130	590-690
CCGT	70-80	350-410
Reciprocating engine	90-100	460-520

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