Bowen Basin Concept Study

Final Report

Queensland Government – Department of Resources

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Executive summary

It is anticipated that new upstream sources of gas supply are required from as early as the mid-2020s, to avoid long-term shortfalls in the East Coast Gas and export markets. The Bowen Basin is one of five 'strategic gas basins' identified by the Commonwealth Government as part of its Gas Fired Recovery Plan that may have a key role to play in bridging this supply-demand gap.

Developing the Bowen Basin has the potential to bring more gas to Queensland's domestic and export markets in addition to making a valuable contribution to Queensland's transition to a low carbon economy through the more productive use of incidental coal mine gas. If it can be brought to market economically, meaning that its cost of production and transport enables a comparable sale price to competing gas sources, and fulfil supply requirements effectively, it has the potential to help drive Queensland's economic prosperity. As such, the Queensland Government's Department of Resources (DoR) is investigating the feasibility of further unlocking the Bowen Basin to:

- Help drive Queensland's community and economic recovery;
- Future proof Queensland's energy supplies;
- Transition to a low carbon, clean growth economy; and
- Make meaningful progress towards the Government's targets of 30% reduction in 2005 emissions by 2030 and zero net emissions by 2050 through Green House Gas (GHG) reduction in the supply chain.

The investigation into unlocking of the Bowen Basin will occur in stages. The Bowen Basin Concept Study (Concept Study, the Study) presents the critical first step in understanding the current and future opportunities the Bowen Basin may present in improving the delivery of gas to the domestic and export markets. It has explored options directed at the following objectives:

- Improving surface economic viability of gas production and providing gas to market to deliver shared benefits for the region and the State as a whole;
- Delivering efficient, multi-user gas transport infrastructure that will unlock gas resources;
- Enhanced commerciality of gas field developments in the Basin;
- Future-proofing gas supplies in Queensland; and
- Better management of incidental coal mine gas.

The purpose of the Concept Study is to ensure that the Queensland Government has the appropriate information to support future decisions on the development of the Bowen Basin. This Concept Study will inform assessment of the economic and technical viability of the development of the Bowen Basin as well as the next steps required to support the development of the Basin.

The Bowen Basin

The Bowen Basin occupies approximately 60,000 km^2, extending from Collinsville in the north to beyond the New South Wales border in the south; it is also overlapped in the southern region by the Surat Basin. The Basin is home to several types of coal seams which have varying potential for gas. It contains three main Permian coal measures – the Rangal Coal Measures (RCM), the Fort Cooper Coal Measures (FCM) and the Moranbah Coal Measures (MCM). The RCM are the shallowest seams in the Basin and have been extensively mined for coal along the eastern and western flanks where, typically, the coal miners target coals that are less than 400m in depth. With four major coal measures of economic importance for coal mining, the Bowen Basin contains the State's most significant Permian coals.

Currently, the Bowen Basin has over 40 active coal mines, two gold mines, producing gas fields and a range of gas and coal exploration and appraisal activities. As a result of this activity, the Basin contains a diverse range of key stakeholders from resource companies, government organisations, utilities providers and gas-intensive manufacturing and power generation assets.

Due to the large extents of the Basin and the significant development occurring in the Surat, the focus of this Study was the northern section of the Bowen Basin, from Collinsville in the north to Emerald in the south (Figure 1). This study area is referred to as the Bowen Basin (or the Basin) throughout the Concept Study.

Figure 1 – Bowen Basin study area

(Source: Department of Resources, Queensland)

Approach to the Concept Study

Due to the complex dynamics of the Australian East Coast Gas Market (ECGM), and an increasing public focus on security of supply and prices, this Study used a demand-led approach to determining the economic need for a new gas basin development. The Concept Study was founded on eight key focus areas, resulting in outcomes that are supported by evidence, and tested with industry:

1. **Understanding future global and local energy markets:** An assessment of global energy demand, in parallel with an understanding of the ECGM supply and its ability to meet demand. This enabled the development of wholesale gas price scenarios for the ECGM over a 10-year time horizon, considering a range of demand, supply, and transport scenarios. This assessment informed the series of potential scenarios for a Bowen Basin development against which the infrastructure requirements have been assessed.
2. **Confirming the need**: An assessment of Australia's gas reserves and alternate sources of supply to confirm the need and priority of further unlocking of the Bowen Basin.
3. **Understanding the resource potential**: An assessment of potential gas production volumes from the Bowen Basin, taking into consideration the level of confidence in available data and uncertainty levels related to the various individual coal measures in the Bowen Basin to produce gas at commercial rates.
4. **Developing production scenarios**: The development of production scenarios determining the readiness of gas resources in the Bowen Basin to produce in the Study period; a 10-year outlook and characterising the key challenge areas to be addressed to develop the Basin.
5. **Understanding the role of Coal Mine Methane:** The quantification of incidental coal mine methane and identification of potential methods of capture and viability to be utilised.
6. **Developing solutions**: Identification of the infrastructure required to bring the Bowen Basin resources to market, focusing primarily on pipelines, as well as considering other options for gas use. The options analysis also included additional supporting infrastructure (e.g. roads and utilities). Access to existing infrastructure and enabling utilities will be critical to the relative economic viability of projects.
7. **Identifying impact**: An understanding of key contextual factors influencing the activation of the Bowen Basin, the possible role of government in facilitating the development of the Basin and the potential impact the development of the Bowen Basin may have on the continued prosperity of the regions.
8. **Defining next steps:** Summarising the necessary roles of government, industry and stakeholders, and defining the logical sequence of next steps to progress the unlocking of the Bowen Basin.

Key findings

The analysis undertaken as part of this Study demonstrates **a clear need for the development of additional gas production capacity** to supplement the predicted shortfall of gas in the ECGM by the mid-2020s.

Whilst other prospective basins exist and could also be developed to provide gas into the ECGM, based on analysis undertaken as part of this Study, **the Bowen Basin is potentially in a prime position** to supply the additional gas requirements due to the level of existing infrastructure, existing production and extensive exploration and appraisal activity within the Basin.

The following sections provide an overview of the key findings of this Study.

1. Understanding future global and local energy markets

Forming a robust view about how the global energy market is expected to evolve over a long-term horizon and identifying a plausible range for the global price of natural gas over the next 30 years is an important requirement when assessing the economic viability of further unlocking the Bowen Basin. The global energy market analysis guides Australia's domestic gas price forecasts by providing an anchor price on which a price specific to the Australian local market can be determined.

KPMG-Macro, a global macro-econometric model, has been used to support the analysis. In general, growth in economic activity depends on, among other things, energy prices, which in turn depend on growth in economic activity. In this framework, faster economic growth tends to push up energy prices, which has a dampening effect on growth. In standard applications of KPMG-Macro, the supply side of the energy market is assumed to accommodate demand.

Over a longer horizon, the key drivers of gas **demand** will be:

- The price of gas relative to the price of substitute fuels (ranging from close substitutes through to not-so-close substitutes);
- Growth in economic activity, including the regional and industrial composition of growth;
- Technological change driving improvements in energy efficiency. This may be partially driven by policy settings; and
- Environmental and other policies designed to increase energy efficiency and change the energy mix.

Over a longer horizon, the key drivers of gas **supply** will be:

- The anticipated market price of gas; and
- Availability of reserves and the cost of extracting, processing and delivering the fuel to users relative to other fuel sources.

Central global demand scenario

The central demand scenario is based on KPMG's current global macroeconomic forecasts for 2021 to 2050. Figure 2 shows KPMG's projections for real Gross World Product (GWP) to 2050. The main feature of these forecasts is that global growth over the next 30 years is expected to be lower than that recorded in the previous 30 years.

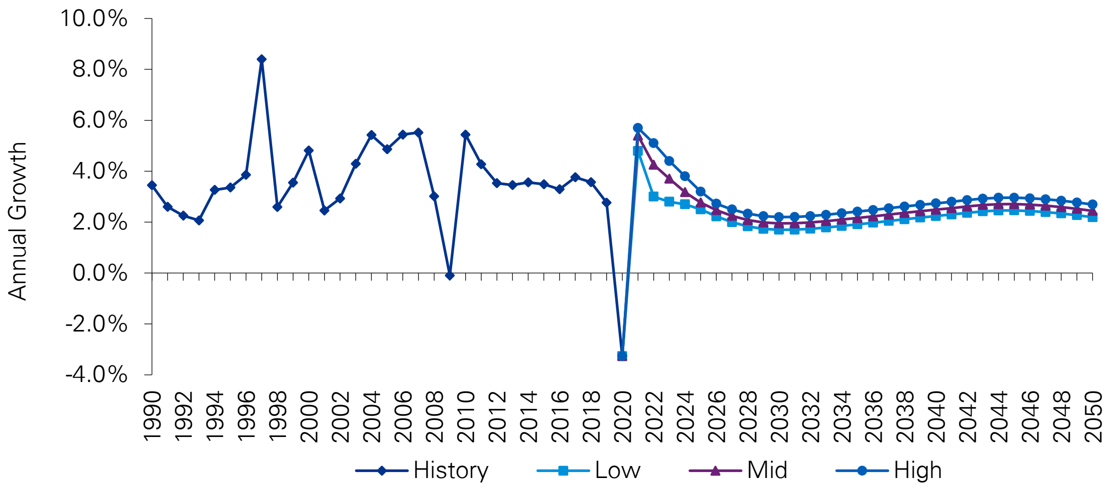


Figure 2 – KPMG-MACRO real Gross World Product forecast, 2021-2050

(Source: KPMG analysis)

Energy price shocks have disrupted economic activity over history, in some cases leading to recession and major dislocation. However, such shocks are, by their nature, largely unpredictable and temporary in nature. In developing the central demand scenario, KPMG has incorporated key assumptions about the (i) industrial composition of the global economy; (ii) energy intensity of the economy; and (iii) share of fossil fuels in the energy mix. These specific energy market assumptions, together with other assumptions embodied in KPMG's global macroeconomic forecasts, yield a central case projection for global energy demand. Figure 3 shows an expected increase in global energy demand from 13,295 Mtoe in 2020 to 18,960 Mtoe in 2045 (a 42% increase in aggregate energy demand).

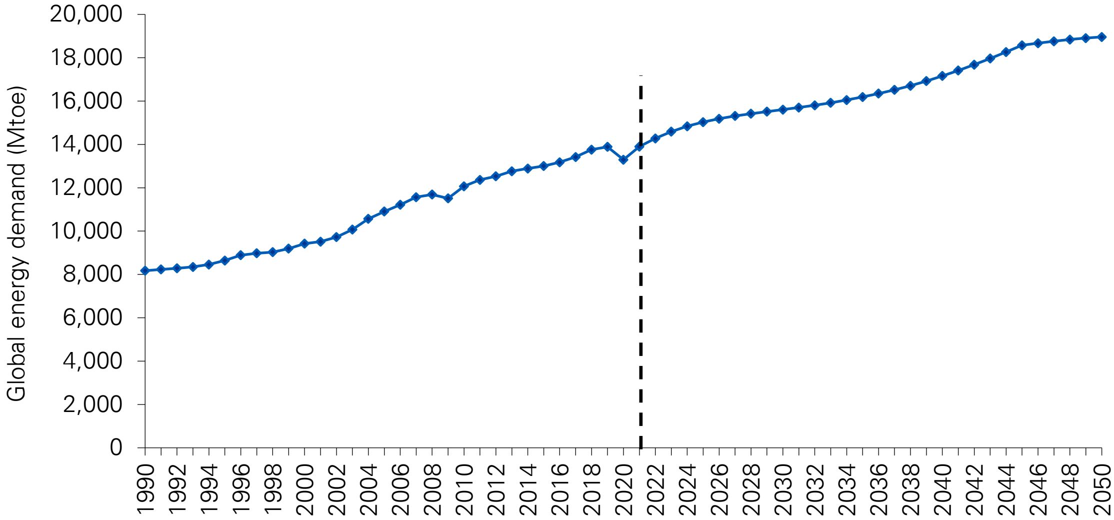


Figure 3 – Global demand for energy, 1990-2050

(Source: BP & KPMG analysis)

Long run JKM LNG price forecasts

Figure 4 below shows the long run projections for a reference to the real (2020 dollars) Japan Korea Marker (JKM) price of Liquified Natural Gas (LNG). In the central case, the real JKM price for LNG recovers from USD$4.40 per Mbtu in 2020 to around USD$8.80 per Mbtu in 2022. The price then declines to around USD$5.20 in 2026 before gradually rising to around **USD$6.20 in 2050**.

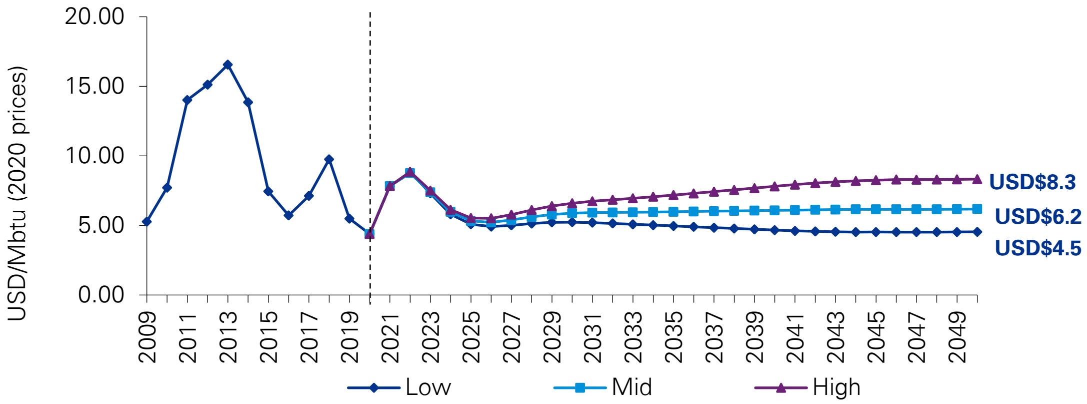


Figure 4 – Projections for the real price of LNG (Japan Korea Marker)

(Source: KPMG analysis)

Linking global and local energy prices

The linking of the domestic gas market with the international LNG market has altered the market and pricing dynamics affecting the ECGM. Connecting Australian market supply to international buyers of LNG (which often commands much higher prices) has enabled the economic development of substantial volumes of high-cost Coal Seam Gas (CSG). It has created opportunities for gas producers to sell gas for export, and for gas buyers to purchase gas that would otherwise be exported during periods of lower LNG prices which reduces risk. As a result, the ECGM has become closely linked with the dynamics of Asian LNG markets and their pricing instruments. This expansion of development to unconventional CSG resources incentivised by the prospect of higher prices has also improved the supply horizon for Australian gas which was previously anticipated to deplete faster due to the lower estimates of economically recoverable gas prior to CSG development.

In theory, the LNG netback price is the price at which LNG exporters are indifferent between exporting LNG and supplying the domestic market as this is the price at which both markets are at parity. An LNG netback price is a measure of an export parity price that a gas supplier can expect to receive for exporting its gas. It is calculated by taking the price that could be received for LNG and subtracting or 'netting back' the costs incurred by the supplier to convert the gas to LNG and ship it to the destination port. Domestic gas buyers in the ECGM are increasingly looking to JKM netback pricing as the benchmark for their domestic contracts, and this is also starting to emerge as a favoured benchmark by various levels of the Australian Government when setting domestic gas policy.

KPMG's forecast long-run real price for LNG (JKM price) in the mid-scenario is USD$6.20/MMBtu, equivalent to AUD$8.35/GJ[1]. Using the Australian Competition and Consumer Commission (ACCC) methodology to calculate Netback at Wallumbilla, our expectation is a long-run **Wallumbilla Supply Hub Netback price of approximately AUD$7.00 to AUD$7.50/GJ**. Stakeholder consultation confirmed that this netback price point is considered a reasonable middle-point for long term gas prices for the ECGM, under balanced ECGM supply and demand conditions. Where supply is tight, the ECGM prices will be elevated, with the Australian Energy Market Operator's (AEMO) General Statement of Opportunities (GSOO) predicting tight supply conditions to persist in the near to medium term.

Volatility will exist in these prices depending on settlement dates for various delivery dates, demand and supply dynamics, short-term market events and other factors. However, using this price point as a guide, it is possible to analyse the economic viability and recoverability of gas from the Bowen Basin using a range of modelling scenarios.

2. Confirming the need

Spread over 14 gas basins, Australia had an estimated 74,992 PJ of 2p reserves and 121,140 PJ of 2C contingent resources in 2019. Three main gas markets have developed around these basins to supply the Australian market:

1. The ECGM;
2. The Northern Gas Market, which was recently linked to the ECGM by means of the Northern Gas pipeline via Mt Isa from the Northern Territory; and
3. The West Coast Gas Market, which is independent of the others owing to the large distance between Western Australia's (predominantly offshore) basins and the Northern and Eastern Markets.

Existing pipeline infrastructure transports gas from production regions, predominantly Queensland, to the regions of high gas demand such as Sydney, Melbourne and Adelaide. Historically the southern basins, such as the Gippsland, Bass and Otway which supplied these high demand regions, contained

[1] Dependent on the exchange rate

large volumes of gas, which was extracted relatively cheaply, however most of these resources are now approaching end-of-life, or have been depleted by decades of extraction.

This has resulted in the need for additional gas to be supplied from the northern states to the southern states and, in the short-to-medium term future, it is likely that net shortfalls on both a daily and annual basis will begin to be realised. These shortfalls may be as much as 300 to 400TJ/d during peak winter demand periods in southern states, starting from the mid-2020s.

As demonstrated by the analysis undertaken as part of this Study, there is a **clear need for the development of additional gas production capacity, either by expanding existing basins, and hence reducing their lifespans, or by developing an additional gas basin** to supplement the predicted shortfall of gas in the ECGM. Increasing supplies of gas from northern states into southern states via increased transport capacity and more efficient use of existing capacity is considered a key part of meeting southern demand. In addition, several projects have been announced that propose to supply alternative sources of gas into southern networks, including LNG import terminals, developing other frontier basins (such as the Beetaloo Basin) and developing other upstream gas projects (such as Narrabri).

Whilst other prospective basins exist and could also be developed to provide gas into the ECGM, based on analysis undertaken as part of this Study, **the Bowen Basin is in a prime position** to supply the additional gas requirements due to the level of existing infrastructure, existing production and extensive exploration and appraisal activity within the Bowen Basin.

3. Understanding the resource potential

The development scenarios used for this Study have been informed by publicly available data layered with assumptions based on NSAI's experience of over two decades of technical work in the Bowen Basin. NSAI started the process by creating well type curve forecasts to represent typical well production over the life of an individual development well in the Bowen Basin.

It is noted that there is a range of coal properties across the Bowen Basin that can affect the production rates of the coals. This Study has attempted to capture the wide range of outcomes with different rates and plateau times using an understanding of what these wells have produced under current conditions as well as what is realistic for future development. As a result, 12 type curves were modelled to incorporate four peak production rates in addition to three plateau periods.

Outlined in Table 1 below are the variables used to generate the well type curves. Each well type curve was built up by combining a selection of each variable, resulting in over 100 individual well type curves being generated. The capex ranges were vetted through stakeholder meetings and agreed that the range represented a reasonable assumption for full development.

Table 1 – Well productivity cases (all variables modelled independently)

(Source: NSAI analysis)

Wellhead gas price *(AUD$ / GJ)*	**Well CAPEX** *(AUD)*	**Well OPEX** ***(AUD / mo)***	**Water Handling Charge** ***(AUD /bbl)***	**Well productivity** ***(TJ/d)***	**Production Plateau Duration** *(years)*	**Total well operational life** *(years)*
$5.00 / GJ $7.00 / GJ $9.00 / GJ	$1 million $1.5 million $2 million	$6,000 pcm	$1 / barrel of water	0.26 TJ/d 0.53 TJ/d 1.06 TJ/d	2 years 4 years 6 years	10 years 15 years 20 years

The analysis showed that meaningful volumes of gas can be produced economically in all but the worst cases, where a low gas price ($5.00 / GJ) is combined with a high well CAPEX ($1.5 or $2 million) and low productivity (0.26 TJ / d). ***Importantly, the overall conclusion from this modelling is that gas***

in the Bowen Basin is considered to be economically recoverable based on reasonable assumptions of cost, revenue, well design and coal geology.

Refer to Table 14 in the body of this report for the detailed results and economic production matrix.

What is included in the gas price?

The gas prices provided in this report are wellhead prices, and do not include transport to Wallumbilla, as the pipeline route, length, size, capacity, utilisation and contracting model is not known at this time. Estimates of a potential tariff for transport of gas from the Bowen Basin vary considerably depending on utilisation of the pipeline, contract durations, volumes and types. A reasonable estimate of a transport tariff from the Basin to Wallumbilla is in the range of $0.70 to $1.20. At this concept stage, given the accuracy of forecast prices and the level of unknowns in the commercial model this pipeline may take, the wellhead price of $7.00/GJ is considered reasonable when compared against a mid-point range of $7.00 to $7.50/GJ at Wallumbilla, depending on exchange rates and other factors. A key next step for understanding the potential of the Basin in more detail would be to develop a detailed commercial model to analyse the potential transport tariff considering the above variables.

4. Developing production scenarios

The Bowen Basin covers a vast geographic area and the coal measures in the Basin vary considerably, as does the amount and quality of subsurface data (including seismic survey, exploration wells, appraisal wells and production wells).

The **Moranbah region** to the north has considerable data, with existing CSG production from the Moranbah Gas Project operated by Arrow Energy.

Whilst a highly active coal mining area, the central **Blackwater region** (from Moranbah in the north to Blackwater in the south) has the least amount of subsurface data related to CSG resources.

The southern **Mahalo region** has been extensively explored, and there are projects advancing to the production stage.

As a result of the combination of varying levels of data (quantity and quality), and the several different coal measures within the Basin, the Bowen Basin production scenarios have been logically split into three main regions (Figure 6) with differing estimates of production as described below and illustrated in Figure 5.

Moranbah region

In the Moranbah region, the modelling indicates that a plateau flow rate of 200 TJ per day can be achieved with drilling and completing 319 wells over the ramp-up phase of development. The well count could include existing wells once prior volume commitments have been fulfilled. To continue the plateau of 200 TJ of gas per day, additional wells are drilled as needed over the next 15 to 20 years, with a peak of 1,059 active wells. It is assumed that 50 TJ of gas per day will be sent to the domestic market in Townsville, and the remaining gas will be transported south via a new pipeline. It is noted that the Moranbah region has several areas available for development with higher production potential than represented with the high case type curve wells, however the production model has been kept purposefully conservative given the concept level of this Study.

Blackwater region

The Blackwater region has the least amount of CSG production and pilot data and is considered to have the highest risk of development; as such, a plateau flow rate of 77 TJ per day has been modelled. The modelling indicates that this target can be achieved with 205 wells drilled and completed starting in 2030. Additional wells are drilled and completed as needed to maintain the 77 TJ of gas per day plateau flow rate over the next 15 to 20 years with a peak of 632 active wells. Delaying a start date until 2030 allows for further delineation and data gathering in the Blackwater region and provides time to establish a firm gas supply in the Moranbah and Mahalo regions to provide economic support for pipeline investment.

Mahalo region

In the Mahalo region, a plateau flow rate of 180 TJ of gas per day has been estimated. Modelling indicates that this rate can be achieved with drilling and completing 319 wells over the ramp-up phase of development. To continue the plateau of 180 TJ of gas per day, additional wells are drilled as needed over the next 15 to 20 years, with a peak in active wells of 1,158 wells. There are existing wells in the Mahalo region that could contribute to the total gas volume if prior volume commitments are fulfilled. The majority of gas volumes from this scenario are available for a pipeline going to southern markets via the ECGM. Similar to the Moranbah region scenario, the Mahalo region also has an area of development that the high-side type curve well could exceed.

The production scenarios modelled have been based on the inputs and assumptions developed through existing knowledge of the Bowen Basin, publicly available data and stakeholder feedback. These result in a number of pathways to economically produce CSG from multiple regions in the Bowen Basin.

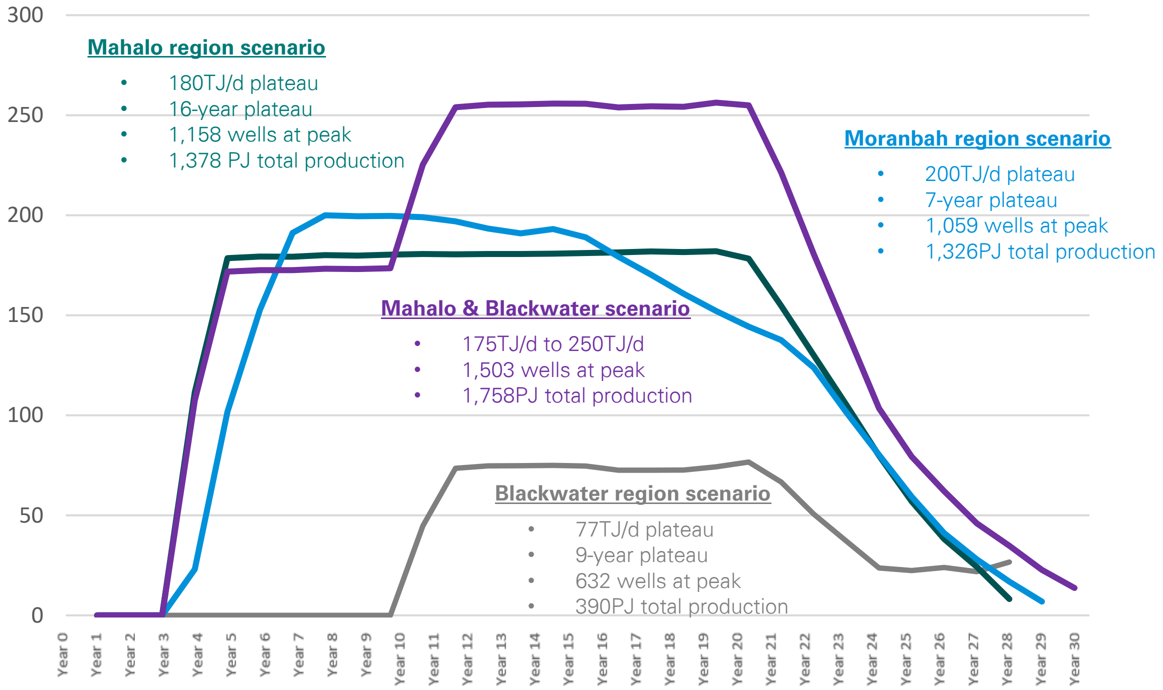


Figure 5 – Modelled gas production profiles – all scenarios

(Source: NSAI analysis)

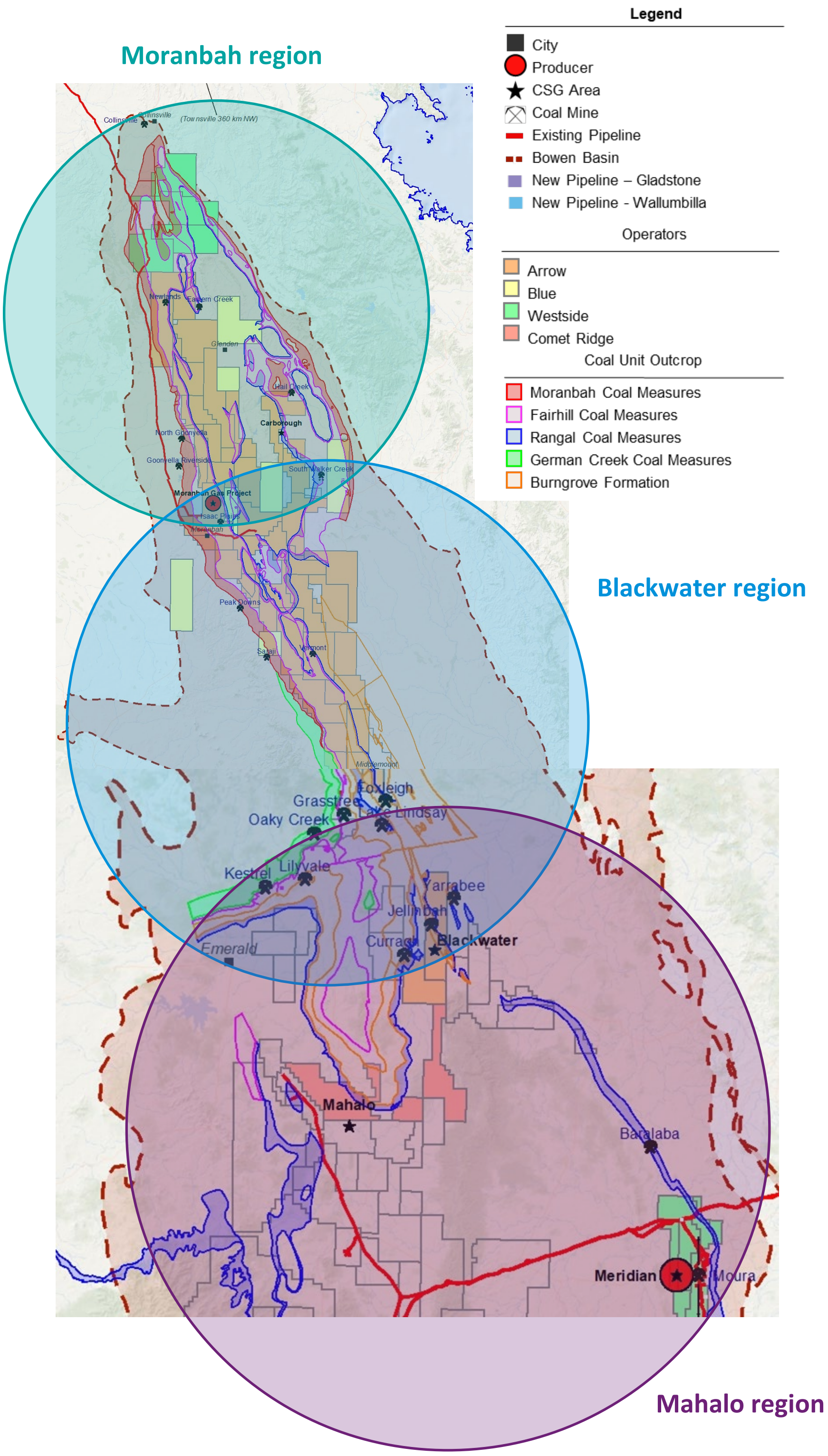


Figure 6 – Production scenario regions of the Bowen

(Source: NSAI Analysis)

5. Understanding the role of coal mine methane

The Queensland State of the Environment Report (2020) confirmed that the outlook for gas and coal mining-based fugitive emissions was on the increase, and that fugitive emissions represented a sizeable portion of Queensland's total emissions (11-15%). The Bowen Basin, which has traditionally focused on coal production, has the potential to bring more gas to Queensland's domestic and export markets – by opening up areas for new (CSG) gas production and capturing unutilised gas from underground mines. However, due to the marked difference in CSG gas and incidental mine gas quality and its unpredictability, and highly variable flow rate, there are potential barriers to effectively capturing and utilising fugitive emissions.

Data obtained from the Clean Energy Regulator (CER) website indicates that CO_2 emissions within the Basin are highest in the central Moranbah and Middlemount regions, with the largest emitters releasing approximately 7.2mtpa, 3.2mtpa and 2.9mtpa CO_2-e for FY19-20. This emission data also provides an indication of which mines have the largest potential for reduction in emissions through utilisation of Coal Mine Methane (CMM).

CMM refers specifically to methane released from coal seams and surrounding strata either just prior or during coal mining (i.e. mining activities). As the build-up of methane in underground mines can create both an explosive and an asphyxiation hazard for mining operations, the CMM must be removed prior to mining operations for safety reasons, and levels of residual methane in the mine must be kept below safe threshold limits. This is achieved through the use of ventilation systems (i.e. ventilation air methane) and/or dedicated relief systems (i.e. drilled boreholes) for surface treatment and/or dispersion.

There are four types of CMM:

- **Pre-drainage or SIS gas,** which is pipeline quality gas, similar to commercial CSG. This gas is produced prior to mining of a particular coal to de-gas it as much as possible and, where possible, gas is provided to CSG operators in the area to supplement their gas production. However, its yields depend on the permeability of the coal being drained.
- **Open cut mine operational emissions** are fugitive emissions from mining operations that occur due to the release of methane from coal extraction, coal transport, coal handling and size reduction operations. Similar to underground mining, large volumes of pre-drainage gas are also produced, as this is the most efficient method of methane removal prior to mining and is necessary to manage for safety reasons.
- **Ventilation Air Methane (VAM)** is by its nature predominantly air and is subject to strict quality controls to ensure the health and safety of mine workers. VAM is therefore not suitable as a recoverable resource using currently available and commercially viable technology.
- **Goaf gas** occurs after pre-drainage methods have maximised the removal of in situ gas through surface or in seam drilling methods. It is generated during longwall cutting or extraction and principally from the caved gob that remains behind the advancing cutting face. Goaf gas therefore combines with a portion of ventilation air that is provided to the working air and does not typically produce gas of high quality for direct use. It therefore requires extra processing before use or can be utilised in certain energy generation applications.

One major Bowen Basin mine currently produces approximately 40 TJ/d of CMM. An approximate breakdown of the daily coal mine gas production is as follows:

- 9 TJ/d is ventilation air methane (VAM), which is vented directly to atmosphere and cannot be flared due to low methane concentration (typically less than 0.5%);
- 18 TJ/d is transferred to Arrow (if it meets pipeline specification gas) or to EDL for local power generation;

- 2.5-3 TJ/d of very low concentration gas is vented in the field, for safety and operability reasons; and
- The remaining 10 TJ/d of gas is flared. As methane (CH_4) has a GWP_{100} (Global Warming Potential over 100 years) of 28, flaring is preferable to venting to reduce the overall greenhouse effect of this gas.

There are a number of barriers to utilising coal mine gas, meaning other coal mines have not been as successful, with another major mine operator in the Bowen Basin providing the following typical usage of coal mine gas:

- 60-70% is VAM, vented directly to atmosphere; and
- The remainder is flared or vented, although the amount flared instead of vented has increased in recent years which has reduced GHG impact. Some of this gas is a mix of various products other than methane which must be separated before use.

Industry's main challenge to utilising coal mine gas in its current operations is that the quality and production rates of coal mine gas are variable, meaning it is not economic to enter into commercial gas supply agreements. However, the gas could be used more effectively on site, such as using pre-drainage gas to displace diesel usage, which contributes to environmental targets and social licence to operate.

To understand the potential quantity of CMM that could be released in the Bowen Basin, modelling of fugitive emissions from CMM was undertaken as part of this Study. Without development of the Basin and assuming no CMM capture, by 2030, the annual fugitive emissions open cut and underground coal mines in CO_2-e is estimated at approximately 29mt of CO2e with a split of:

- 19mt from open cut operations;
- 3.5mt from pre-drainage;
- 1.5mt from goaf gas; and
- 5mt from VAM.

When compared to other components (VAM, Goaf, pre-drainage underground and pre-drainage gas), the *largest single source* of coal mining GHG emissions are from open cut mine operational fugitive emissions. Typically, the viability of pre-drainage is dependent upon the depth of the mine with open pit mines deeper than 200m being advised to employ pre-drainage during operation. Operational emissions cannot be captured as they are generally emitted during recovery of the coal as overburden is removed and pressures on the coals reduced.

When considering the development of the Basin, forecast fugitive emissions were modelled for all four production scenarios. The modelling indicated that the total emissions are forecast to be below 10Mt CO_2-et over the life of the project.

The fugitive emission modelling indicates that **the reduction in fugitive emissions from utilising CMM capture, even if only a small portion of the total, will far outweigh the GHG emissions impact of developing the Basin as a CSG play**. This is largely due to methane having a GWP_{100} of 28, and hence capturing and combusting it will have a net positive effect on the emissions of the project despite the emissions required to develop the Basin.

Strategies for improved future utilisation, and therefore enablement of production and beneficiation of CMM, are likely to be crafted around the following key focus areas:

- **Overlapping tenements**: New frameworks for coal and CSG overlapping tenures must continue to strive for maximum flexibility for resource authority holders, inclusive of the ability for relevant parties to mutually agree on non-regulated arrangements that may fall outside legislative or default requirements.

- **Subsidisation:** Power station and/or other gas beneficiation facilities will have a greater chance of development through participation in emerging or potential future emissions subsidy schemes.
- **Transmission Networks:** Upgraded transmission systems may encourage or enable larger power plants and drive common use infrastructure (e.g. gathering and transmission pipelines to centralised power plants).
- **Ventilation air methane:** Mines could be incentivised to reduce VAM from established baseline emissions through either emissions crediting or direct regulation.
- **New Markets:** New energy supply chains could be considered utilising either CSG and low-quality gas associated with its production or incidental mine gas that has been treated to suitable quality, although not necessarily pipeline specification gas.
- **Infrastructure:** Access to pipelines. One of the most significant barriers to utilising pre-drainage coal mine gas is access to export pipelines, due to the typical lack of proximal export pipelines, and the lack of required gas infrastructure to meet pipeline quality and pressure requirements. For these reasons, it is typically not economic to capture coal mine gas and export it to the commercial market.
- **Gas Quality Requirements:** CMM is typically highly variable in quality and flow, hence it can be a challenge to deliver consistently economic gas to market at suitable quality.
- **Emerging Technology:** Developing and incorporating the use of emerging technology, such as membrane separation of methane to improve concentration to useable levels, has the potential to change the dynamics of CMM utilisation in the Basin.

Traditionally, mine operators have been averse to either investing in new gas processing infrastructure or owning and operating that infrastructure. Generally, mine operators are supportive of power generation and moving surplus energy as "electrons" as opposed to "molecules". The current business landscape therefore suggests that policy drivers, improvements to the regulatory frameworks and cross sector collaboration from both private and public sector players will be critical to the development of the Bowen Basin gas resources and the reduction of fugitive emissions.

6. Developing solutions

Infrastructure development

The analysis undertaken as part of this Study indicates that the existing infrastructure to ship gas north from Moranbah to Townsville and other regional centres nearby is sufficient to cater for the expected demand in these areas, with little further infrastructure required.

However, with limited existing infrastructure in the central region, combined with large gas resources currently not connected to the ECGM, a new transmission pipeline connection is necessary to meet long-term market requirements. There are several likely options for pipeline routes that could connect the Mahalo, Blackwater and Moranbah regions to the ECGM:

- Routes developed as part of this Study; and
- Routes that have been proposed by industry.

Four routes were developed as part of this Study as illustrated in Figure 7. These routes should only be considered indicative of likely corridors for a pipeline – it is important to understand that this assessment is provided only to: confirm that reasonable pipeline corridors exist; determine the likely length of pipelines; enable estimated pipeline diameters and costs to be developed; and provide an understanding of key options in macro-level pipeline routing for the Bowen Basin.

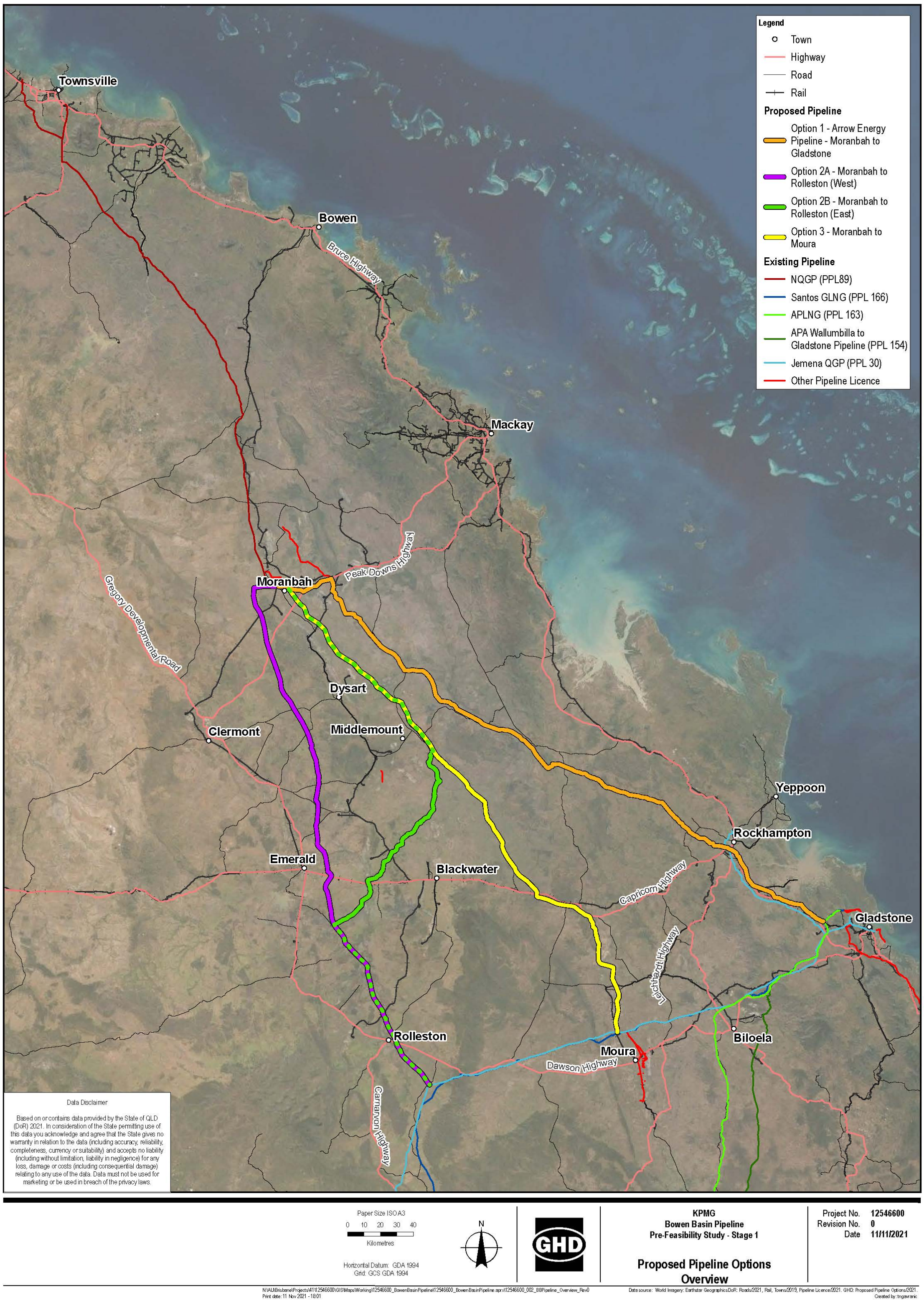


Figure 7 – Identified Pipeline Options

(Source: GHD analysis)

Identification of a preferred option

The selection of a particular pipeline route from one point to another requires a multi-criteria assessment to optimise the many constraints. Route selection is ultimately an iterative process requiring consultation between landowners, regulatory bodies, pipeline owners, engineers, constructors and other project stakeholders. However, to inform the outcomes of this Study, a Strategic Merit Test (SMT) was undertaken.

The SMT was undertaken using the Government's objectives for the Basin as part of this Study, with results summarised in Figure 8 below.

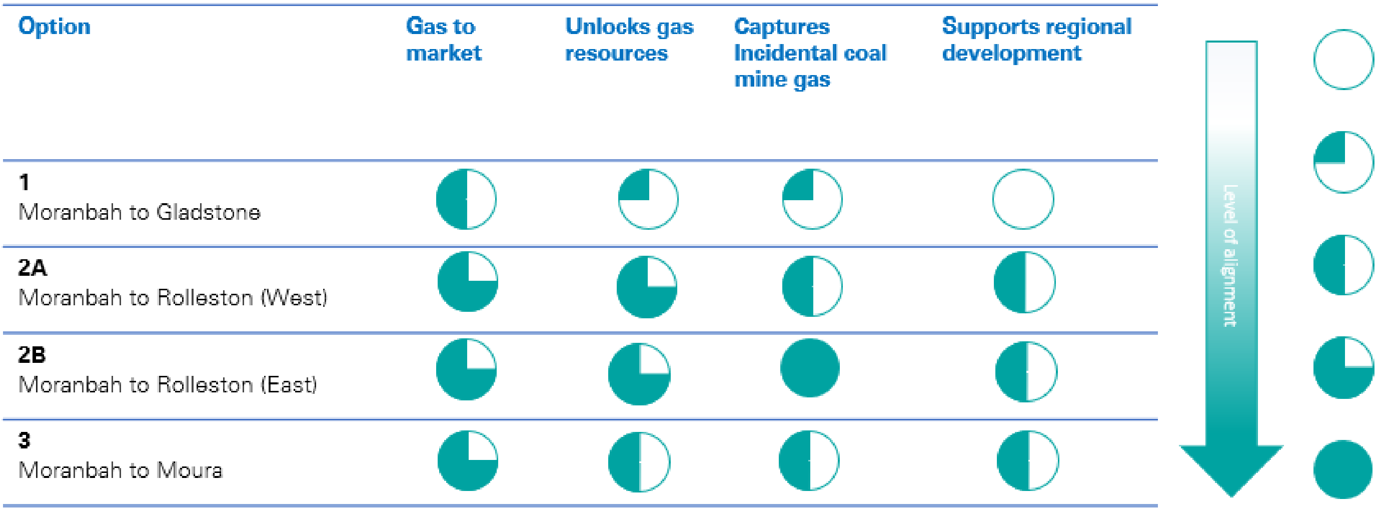


Figure 8 – Strategic Merit Test
(Source: KPMG analysis)

Explaining the SMT

Gas to market

Due to the need to service the expected shortfall of gas supplies into the ECGM by the mid-2020s, the assessment was based on connecting the Bowen Basin to the ECGM. Whilst forecasts from AEMO can and do move around with time, given that they are a snapshot of a dynamic market, the overall conclusions from our analysis are that there is a trend of supply/demand gaps emerging beyond the end of this decade, and that more gas is needed based on current demand forecasts.

It is considered that Option 1 would be more effective for export of gas via LNG through its connection to Gladstone. Options 2A, 2B and 3 with a connection to Wallumbilla, would be more effective for supply to the ECGM. However, it is noted that once a connection is made into a pipeline, there are commercial ways to get contractual gas flows to the customer within the ECGM or to LNG export (location-based gas swaps).

There is a higher capex involved for Option 2B but there is likely a greater upside with more gas being able to access the pipeline (multiuser). Option 2B would be able to capture more of the gas suitable for pipeline injection from the Moranbah, Blackwater and Mahalo regions, when compared to Option 2A. Option 2A presents a similar opportunity, however, it is expected that it would be more difficult economically to access gas resources in the Blackwater region.

Unlocking gas resources

The assessment was based on the number of gas permits the pipeline route supports.

When considering the options, Option 1 with a connection to Gladstone does not effectively capture the majority of gas permits in the Basin, supporting only the unlocking of the Moranbah region. Furthermore, it would require a significant gathering network and large processing facilities in Moranbah.

Options 2A and 2B with a connection to Wallumbilla support a whole-of-Basin solution, passing close to many existing exploration permits across both the Blackwater and Mahalo regions. Due to the close proximity of the existing exploration permits, these options also require a less significant gathering network, with several smaller processing facilities for local tie-in to the pipeline.

Although Option 3 provides a connection to Wallumbilla from Moranbah, as there are limited mine or petroleum leases between Blackwater and Moura, the southern half of this route is not expected to be as prospective for gas sources as Route Option 2B.

Capturing incidental coal mine gas

Options 2A and 2B run in close proximity to the existing exploration permits and maximise the utility of methane from coal in the Basin, from both mining operations and coal seam gas production. Option 2B provides the closest access to the majority of the prospective resource and is considered the route which maximises the capture of incidental coal mine gas. As described above, the southern half of Option 3 is due to the limited mine or petroleum leases between Blackwater and Moura.

Due to its alignment, there is limited opportunity for Option 1 to capture incidental coal mine gas.

Supporting regional development

By supporting the development of the whole Basin, Options 2A, 2B and 3 offer a range of regional development opportunities. By only supporting the development of the Blackwater region and its supply of gas predominately to the LNG export market, Option 1 is considered to result in minimal regional development opportunities.

When considering the Government's objectives for the Basin as part of this Study, based on the above SMT, **Option 2B delivers the greatest alignment to achieving these strategic outcomes**.

Table 2 below details the technical parameters of Option 2B.

Table 2 - Option 2B – To Rolleston (East) gas infrastructure
(Source: GHD Analysis)

Parameter	Mahalo	Mahalo + Blackwater + Moranbah
Flowrate	180 TJ/d	**375 TJ/d** (Mahalo 150 TJ/d + Blackwater 75 TJ/d + Moranbah 150 TJ/d)
Required Infrastructure	~ 1,158 wells & gathering network 2 x new gas processing facilities End of line compression (~7 MW) DN400, 140 km pipeline operating at 10.2 Mpag	~ 2,400 wells & gathering network 4 x new gas processing facilities and MGP expansion End of line compression (~ 9MW) DN550, 390 km pipeline operating at 10.2 Mpag
Estimated Capital Expenditure	Wells/gathering: $1-1.5M per well Processing facilities: $630M Pipeline: $160M	Wells/gathering: $1-1.5M per well Processing facilities: $1,225M Pipeline: $600M
Development Timeline (best case)	4 years	6 years
Risks	Would need to oversize initial southern pipeline (to DN550), loop in the future, or add additional future compression, to unlock Moranbah. Additional upfront cost on oversized pipeline adds ~40% to pipeline cost only.	Viability of wells in central Bowen is unknown, pipeline would need to extend to Moranbah for proven resources Constructability of pipeline route through Middlemount and Blackwater due to mines

Notes:

1. *Compression has only been allowed for at the GPFs and end of line to tie into QGP.*
2. *Pipeline capacity could be expanded in the future up to 400 TJ/d by adding mainline compressor stations.*
3. *Of the 200 TJ/d from the Moranbah region as stated in the production scenarios (refer Figure 6), 50 TJ/d has been assumed to be transmitted North via the NQGP, with the remainder being transmitted via the new pipeline to Gladstone.*

Approval pathways

A significant number of environmental and planning approvals are required for major petroleum and gas projects in Queensland to proceed, with the most critical approval being the Environmental Impact Statement (EIS). An effective and proactive engagement program is also essential to manage approvals and mitigate the potential for approval delays. The complexity of major petroleum and gas projects also requires an effective interface between the proponent, community consultation team, environmental specialists and the engineering teams. This is necessary to manage approvals issues that may arise.

Key approval considerations that have the potential to impact a project schedule, particularly for major petroleum and gas projects in Queensland, are:

- Water;
- Land acquisition;
- Overlapping tenure;
- Coexistence issues;
- Stakeholder engagement;
- Native Title;
- Environmental constraints; and
- Environmental offsets.

There is potential for the Queensland Government to designate an infrastructure corridor to fast-track development within the Bowen Basin. This infrastructure corridor would enable not only pipeline development, but utilities development as well as gas, power and water.

It is considered that the coordination and declaration of a State Development Area (SDA) could also present an avenue to facilitate the establishment of a gas pipeline in the Bowen Basin, however this would need to be considered in the context of the enabling legislation.

7. Identifying impact

Key risks and opportunities

Developing the Bowen Basin will be complex and challenging, but it has the opportunity to improve Queensland's productivity, liveability and environmental sustainability. Key to maximising the benefits to Queensland will be converting the challenges to opportunities.

Development of the Bowen Basin could improve the prosperity of Queensland, most notably the regions. The supply of market-competitive economic gas is expected to secure a new revenue stream to replace coal royalties and stimulate industrial development, particularly in the northern regions such as Townsville. This could have flow-on effects through to jobs and economic growth for future generations. However, in order to deliver this, three key barriers have been identified that must be overcome:

- **A need to change the current state of play:**
  - There is a need to increase the appetite to invest for incumbent players.
  - Creating a diverse and strong consumer demand for the gas for industry to underwriting a large-scale development of upstream CSG reserves.
- **The Bowen Basin is technically challenging:**
  - Evidence from existing production and exploration wells demonstrates that the Bowen Basin coals have lower permeability, are located deeper and are higher pressure than the Surat Basin coals.
  - The use of enhanced recovery techniques, such as hydraulic fracturing, which brings with it a range of technical, social and environmental risks, may be required.
  - Wells also need to target specific coal seam measures to ensure productivity.
  - Sufficient reserves need to be certified in a timely manner.
- **Navigating a complex stakeholder landscape**:
  - The Bowen Basin coal measures are shallower on the eastern and western flanks – these measures are the ones that are being extracted by Queensland's large coal mining industry.
  - Beyond 800m depth, it is difficult to economically extract CSG – meaning that CSG development in the Bowen Basin will require strong cooperation between CSG proponents and coal miners.
  - Overlapping tenure on the same acreage is possible and presents immense opportunity to capture coal mine fugitive gas emission, but also introduces complexity.

The role of Government

All tiers of government (Commonwealth, State and Local) will need to play a pivotal role in facilitating the development of the Bowen Basin if it is to maximise its benefits. To facilitate the development of the Bowen Basin to the benefit of all Queenslanders, and in response to stakeholder challenges, three key focus areas for government are starting to emerge:

- **Enabling infrastructure:** Facilitating, through direct investment, subsidy, or other de-risking measure, the construction of common infrastructure to enable access to market, delivering affordable gas supplies, increasing competition, building international competitiveness and attracting private investment.

- **Supporting zero net emissions by 2050**: Leading by example in reducing fugitive emissions, investing in exploration activities and technology to improve the scientific understanding of geosciences data needed by industry.
- **Growing our regions**: Strengthening the regions' economies by supporting ongoing jobs across supply chains, industries investing in skills for the development of next generation of workers and creating new economic opportunities through diversification of the regions' economic base. Improving the resilience of Queensland's regions through investment in community infrastructure.

These focus areas straddle numerous portfolios across all tiers of Government, with numerous initiatives already underway that will inform and influence the development of the Bowen Basin. However, **the unlocking of the Bowen Basin cannot be delivered by Government alone – industry must play their part.**

To strengthen the regions' economy and instil confidence for industry to invest, an agreed narrative on how Queensland will navigate the energy transition, combined with a strategic approach to planning and investment across all tiers of Government and industry, will be required. This approach will ensure that the benefits of individual initiatives across portfolios and industry will be maximised.

The most likely scenario

There is a demonstrated risk of shortfalls in gas supply which imply a clear need for additional gas production within Australia to supply the expected shortfall in the ECGM from the mid-2020s. Various projects and initiatives are slated to address these forecast shortfalls, however no single project is a solution. As such, there is clear potential for the Bowen Basin to be developed as a new upstream source of gas that, if connected to the ECGM, would help contribute to closure of the projected supply-demand gap.

Findings within this Study have identified that there are economically viable scenarios that could unlock production from the Bowen Basin in volumes that will provide meaningful additional gas supplies to market at a competitive price. However, to underpin the development of the Basin, the construction of a new pipeline connecting the Basin to the ECGM will be required - only supporting the smaller play of shipping gas from Moranbah to northern regional demand centres will not be sufficient to underpin the development of the entire Basin.

At a netback price point of approximately AUD$7.00 to $7.50 / GJ at Wallumbilla, a number of pathways to economically produce natural gas from multiple regions in the Basin have been identified. At this price, it is anticipated with moderate levels of certainty that it will be possible to produce:

- Up to 180TJ/d from the Mahalo region, and a total of approximately 1,200PJ over the field life;
- Up to 80TJ/d from the Blackwater region, and a total of approximately 375PJ over the field life*; and
- Up to 200TJ/d from the Moranbah region, and a total of approximately 1,200PJ over the field life.

** A lack of exploration and appraisal data specific to CSG production in the Blackwater region means this figure is purposefully conservative pending further exploration based on the geographic and geophysical nature of the region.*

It is anticipated (based on forecasts and the assumptions and findings contained within this report) that these production levels will be supported by a staged development of a pipeline, with the first stage connecting the Mahalo region to Wallumbilla, and a future extension from Mahalo to Moranbah. This staged approach has the benefit of supplying gas into the ECGM with less upfront capital investment required, creating confidence for industry to invest and providing time for the certification of sufficient reserves in the Blackwater region. Option 2B achieves a higher utility of CSG resources and pre-drainage CMM from coal mines in the Basin than would otherwise not be realised, as it provides the closest access to the majority of both of these prospective resources. However, further investigation into the constructability of the pipeline through mining operations and leases needs to be undertaken.

Getting the timing right for the development of the Basin will largely determine the resulting benefits to Queensland. There are many factors that need to be considered from a timing perspective, however an overriding factor is the forecast supply shortage in the ECGM. This implies that, for a pipeline to be able to supply the market, the pipeline development would likely need to take Final Investment Decisions (FID) by late 2023. Additionally, there would need to have been sufficient development of reserves through exploration to de-risk the FID such that there is confidence in upstream economic reserves instead of estimated resources that would underpin a large investment in a pipeline.

The analysis undertaken as part of this Study indicates that the *'best case'* timeline for a material increase in gas production in the Basin is approximately five years, however historical Basin development and industry feedback indicate that the *most likely* timeframe for development of the Basin is seven years.

With any pipeline asset development, the timing, configuration, and routing of the Bowen Basin pipeline will be dependent on which party or parties take the commercial risk to invest into the asset.

A key role for the Queensland Government in subsequent phases of the development of the Bowen Basin is to clearly articulate to industry their objectives for the development of the Basin and measures to help mitigate risks in the construction of the pipeline.

8. Defining next steps

Embracing the development of the Bowen Basin is expected to help drive Queensland's economic recovery whilst transitioning to a low carbon, clean growth economy. The development of the Bowen Basin will impact and provide benefits across all tiers of government and many portfolios, and this Study has demonstrated the criticality of pipeline infrastructure to the further unlocking of the Basin.

However, the unlocking of the Bowen Basin cannot be delivered by government alone; industry must play their part. Therefore, it is recommended that the proposed next step for the Bowen Basin is to undertake a Structured Market Engagement process.

Structured Market Engagement Process

To encourage industry participation and create confidence for industry to invest, both the Commonwealth and Queensland Governments must be an informed leader in the development of the Basin. Key to testing and refining the role of government in unlocking the Bowen Basin is a Structured Market Engagement Process with likely market participants and other identified stakeholders.

Key elements of the process could include:

- **Identification of market participants:** Confirm market participants and key stakeholders to ensure equal opportunity to all.
- **Refining the potential role for government:** Build upon the current understanding from the market to clearly identify where government may best play a role in the short to medium term in supporting industry.
- **Testing potential government processes:** Test and refine, through market feedback and collaboration with the Commonwealth Department of Industry, Science, Energy and Resources (DISER), a commercial model and process for potential government support (financial and/or in-kind) and roles and responsibilities to support collaborative feasibility development.
- **Identifying key thresholds:** Identify, in consultation with market participants, key hold points and thresholds that would need to be satisfied for investment decisions.
- **Establishing indicative timetables and cost of development:** Establish, in consultation with market participants, a reasonable timetable, indicative cost for feasibility development and key milestones therein.

This Study has identified several market participants and some of their drivers. The Structured Market Engagement Process will build upon this knowledge and would incorporate the more traditional next step of a feasibility study by building an understanding of the commerciality of the pipeline from the market's perspective. This approach is anticipated to improve private sector confidence in the establishment of the Bowen Basin, resulting in significant time savings.

1. Introduction

1.1 Background

It is anticipated that new upstream sources of gas supply are required over the long term, from as early as the mid-2020s, to avoid shortfalls in the East Coast Gas and export markets. The Bowen Basin is one of five 'strategic gas basins' identified by the Commonwealth Government as part of its Gas Fired Recovery Plan that may have a key role to play in bridging this supply-demand gap.

Developing the Bowen Basin has the potential to bring more gas to Queensland's domestic and export markets in addition to making a valuable contribution to Queensland's transition to a low carbon economy through the more productive use of incidental coal mine gas. If it can be brought to market economically, meaning that its cost of production and transport enables a comparable sale price to competing gas sources, and fulfil supply requirements effectively, it has the potential to help drive Queensland's economic prosperity. As such, the Queensland Department of Resources (DoR) is investigating the feasibility of further unlocking the Bowen Basin to:

- Help drive Queensland's community and economic recovery;
- Future proof Queensland's energy supplies;
- Transition to a low carbon, clean growth economy; and
- Make meaningful progress towards the Government's targets of 30% reduction in 2005 emissions by 2030 and zero net emissions by 2050 through Green House Gas (GHG) reduction in the supply chain.

Investigation into further unlocking of the Bowen Basin will occur in stages. This Concept Study presents the critical first step in understanding the current and future opportunities the Bowen Basin may present in improving the delivery of gas to the domestic and export markets. It will explore options focussed on the following objectives:

- Improving surface economic viability of gas production and providing gas to market to deliver shared benefits for the region and the State as a whole;
- Delivering efficient, multi-user gas transport infrastructure that will unlock gas resources;
- Enhanced commerciality of gas field developments in the Basin;
- Future-proofing gas supplies in Queensland; and
- Better management of incidental coal mine gas.

1.2 Purpose of this report

The purpose of this report is to ensure that the Queensland Government has the appropriate information to support future decisions on the development of the Bowen Basin. Founded on a robust evidence base, this report will provide a consistent reference point to enable conversations between industry and agencies of Government required to optimise the Basin's development and community outcomes. This report will establish the economic and technical viability of the development of the Bowen Basin as well as inform future investigation required to support investment decisions.

The outcomes documented in this report will form an independent clear plan, charting the scenarios and actions to help guide the next stage of development within the Bowen Basin.

1.3 Report structure

This report is structured as follows:

- Section 2 describes the **scope of this Concept Study**, including the study area, key inputs and approach to stakeholder engagement.
- Section 3 provides an overview of Australia's existing gas resources and infrastructure.
- Section 4 identifies the **global energy outlook**, providing a summary of key findings from technical analysis into the price environment for gas and associated products as well as the potential commercial viability of extraction of these resources.
- Section 5 describes the **domestic energy market** and assesses the need for the development of an additional gas basin in Australia. The assessment is underpinned by supply and demand forecasts and the existing infrastructure supporting the domestic gas market. This assessment, in combination with the global energy outlook, have informed a series of potential scenarios for Basin development against which the infrastructure requirements have been prepared.
- Section 6 describes the **potential role of the Bowen Basin** in meeting the forecast global and domestic demand for gas resources, including identified challenges and opportunities of the Basin.
- Section 7 details the **potential market and production development scenarios** identified for the Bowen Basin. These low, mid and high production scenarios provide a sensitivity check and have been founded on an independent assessment of the resource potential and recovery of the Bowen Basin.
- Section 8 quantifies the **Bowen Basin's fugitive emissions** and the potential pathways for coal mine methane capture.
- Section 9 outlines the **infrastructure options** relating to transport and transmission, potential common user facilities and other infrastructure as required by industry and timescale.
- Section 10 outlines the **potential approval pathways** available to facilitate the development of the Bowen Basin.
- Section 11 identifies the **most likely scenario** for the development of the Bowen Basin, confirming the need for the development of the Basin and highlighting the risks and opportunities including the likely timing.
- Section 12 outlines the **potential role of government** in facilitating development of the Bowen Basin.
- Section 13 identifies a suite of **next steps** for the Queensland Government to consider in progressing the unlocking of the Bowen Basin.

2. Scope of the study

2.1 Scope overview

The scope of the Study encompassed the following:

1. An overview and analysis of the supply, demand and price of wholesale gas in the eastern Australian gas market over the next 10 years (the study period), including demand and supply forecast scenarios and an exploration of physical and market constraints and influencing factors.
2. An assessment of upstream gas resources in the Bowen Basin to determine their readiness to produce within the study period, including an outline of booked reserves and resources, and identification of technical production challenges, infrastructure, financial and commercial and other barriers to developing the gas resource.
3. Analysis of current and predicted sources of incidental coal mine gas to be captured from coal mines in the study, including an outline of options to utilise incidental coal mine gas more productively and the necessary regulatory and market conditions required to facilitate this.
4. An outline of the base-case (most-likely) scenario for developing gas resources in the Bowen Basin.
5. Sensitivity analysis of the base case scenario (i.e. how changes to key assumptions would materially impact gas supply for the domestic market).
6. A set of options for facilitating the development of gas resources in the Bowen Basin, leveraging existing Government initiatives such as the Australian Government's Gas-fired Recovery including, but not limited to, gas pipeline infrastructure.
7. Recommendations for further analysis in subsequent phases of this project.

2.2 Study area

As illustrated in Figure 9, the Bowen Basin occupies approximately 60,000 km^2, extending from Collinsville in the north to beyond the New South Wales border in the south; it is also overlapped in the southern region by the Surat Basin. The Bowen Basin is home to several types of coal seams which have varying potential for gas. It contains three main Permian coal measures – the Rangal Coal Measures (RCM), the Fort Cooper Coal Measures (FCM) and the Moranbah Coal Measures (MCM). The RCM are the shallowest seams in the Bowen Basin and have been extensively mined for coal along the Eastern and Western flanks where the coal is shallowest and typically, coal miners target coals that are less than 400m depth. With four major coal measures of economic importance for coal mining, the Bowen Basin contains the State's most significant Permian coals.

The Bowen Basin has over 40 active coal mines, two gold mines, producing gas fields and a range of gas and coal exploration and appraisal activities. As a result of this activity, the Basin contains a diverse range of key stakeholders from resource companies, government organisations, utilities providers and gas-intensive manufacturing and power generation assets.

Due to the large extents of the Bowen Basin and the significant development occurring in the Surat, the focus of this Study was the northern section of the Basin, from Collinsville in the north to Emerald in the south, as highlighted in Figure 10. This study area is referred to as the Bowen Basin (or the Basin) throughout this report.

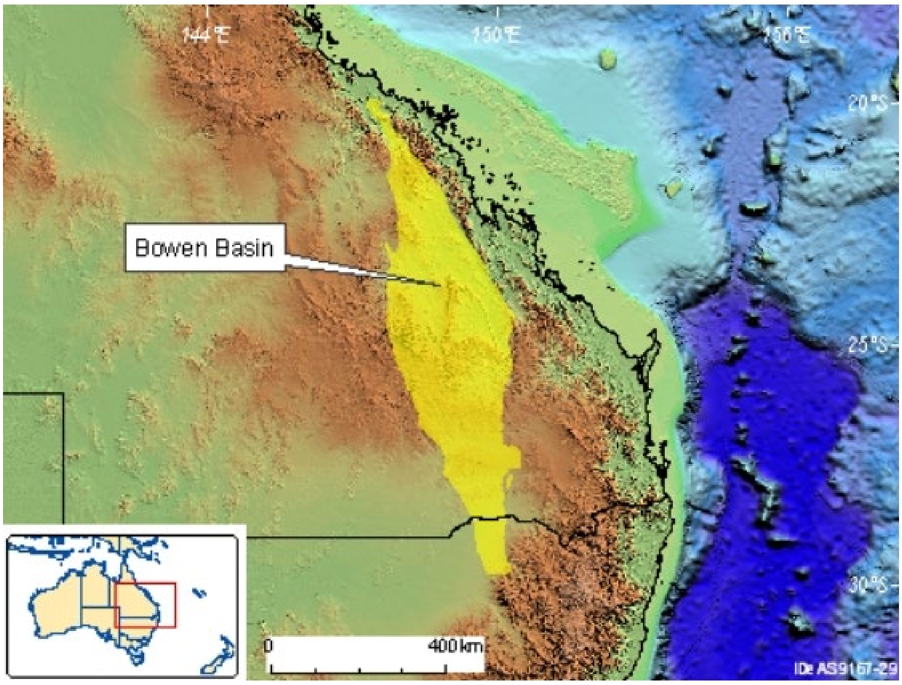


Figure 9 – Bowen Basin
(Source: Geoscience Australia)

Figure 10 – Study Area
(Source: Department of Resources, Queensland)

2.3 Approach to the study

To understand if further unlocking of the Bowen Basin is a viable option in supporting Australia's gas reserves, this Study implemented a demand-led approach. This approach accounted for the complex and variable dynamics of the East Australian Gas Market (ECGM), and an increasing public focus on security of supply and prices. The Study was founded on six key focus areas, resulting in outcomes that are supported by evidence and tested with industry:

1. **Understanding future global and local energy markets:** An assessment of global energy demand, in parallel with an understanding of the ECGM supply and its ability to meet demand. This enabled the development of wholesale gas price scenarios for the ECGM over a 10-year time horizon, considering a range of demand, supply, and transport scenarios. This assessment informed the series of potential scenarios for Bowen Basin development against which the infrastructure requirements have been assessed.

2. **Confirming the need**: An assessment of Australia's gas reserves and alternate sources of supply to confirm the need and priority of further unlocking of the Bowen Basin.

3. **Understanding the resource potential**: An assessment of potential gas production volumes from the Bowen Basin, taking into consideration the level of confidence in available data and uncertainty levels related to the various individual coal measures in the Basin to produce gas at commercial rates.

4. **Developing production scenarios**: The development of production scenarios determining the readiness of gas resources in the Bowen Basin to produce in the Study period; a 10-year outlook and characterisation of the key challenge areas to be addressed in order to develop the Basin.

5. **Understanding the role of Coal Mine Methane:** The quantification of incidental coal mine methane, potential methods of capture and viability to be utilised were also assessed.

6. **Developing solutions**: Identification of the infrastructure required to bring the Bowen Basin resources to market, focusing primarily on pipelines, as well as considering other options for gas use. The options analysis also included additional supporting infrastructure (e.g. roads and utilities). Access to existing infrastructure and enabling utilities will be critical to the relative economic viability of projects.

7. **Identifying impact**: An understanding of key contextual factors influencing the activation of the Bowen Basin, the possible role of Government in facilitating the development of the Basin and the potential impact the development of the Bowen Basin may have on the continued prosperity of the region.

8. **Defining next steps:** Summarising the necessary roles of Government, industry and stakeholders, and defining the logical sequence of next steps to progress the unlocking of the Bowen Basin.

Box 1: What do we mean by economic viability of the Bowen Basin?

For the purposes of this Study, economic viability of the Basin was defined as simply the cost of production and transport to enable a comparable sale price to competing gas sources within Australia.

2.4 Understanding the evidence base

2.4.1 Available data on recoverable supply

The assessment of upstream gas resources in the Bowen Basin, including an outline of booked reserves and resources, has been informed by publicly available data. It is noted that significant explorative works have been undertaken by proponents in the study area, however, due to commercial confidentiality reasons, this information has not been used in the formation of the productivity scenarios. In lieu of industry data, testing of the productivity scenarios with industry has formed a critical input into the Study to ensure confidence in the results.

Refer to Section 7.1 for the detailed methodology adopted for the assessment of upstream gas resources.

2.4.2 Industry engagement

Hearing the voice of industry around the likely factors that will influence their investment decisions, both those within and outside of Government control, is critical to ensuring that the Queensland Government has the information it requires to set appropriate policies and facilitate infrastructure investment that is conducive to accelerating the development of the Bowen Basin.

Over the course of the engagement, key industry stakeholders that have a vested interest in the Bowen Basin were extensively engaged to gather views and test insights, forecasts and analysis. Figure 11 illustrates the industry stakeholders that have provided input into this Study.

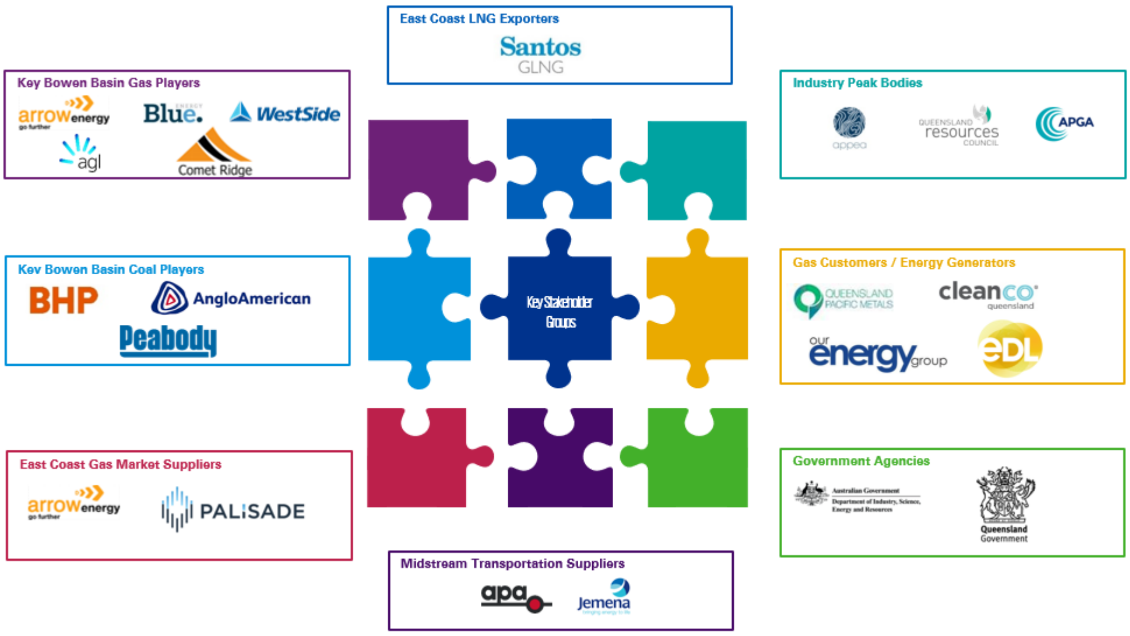


Figure 11 – Key industry stakeholders

(Source: KPMG analysis)

Industry engagement was undertaken in three phases with a focus on understanding:

- Demand and supply trends;
- Well economics;
- Potential opportunities and how to maximise the benefits;
- How government can help unlock the Basin; and
- Key risks.

Industry engagement throughout the project has resulted in a robust and pragmatic Concept Study with insights being informed by industry feedback. It is anticipated that this approach will enable a strong alignment between both Government and industry on the next steps for the development of the Bowen Basin.

3. Australia's gas resources

3.1 Overview

Spread over 14 gas basins, Australia has large reserves of natural gas with over 116,000 PJ of proved and probable (2P) reserves under the JORC[2] definition, making natural gas Australia's third largest energy resource. Gas is located within several high-density areas, such as the Carnarvon and Surat-Bowen Basins which, together, contain more than half of Australia's reserves.

Australian gas is a variety of wet and dry natural gas, predominantly comprised of methane, much of which is contained within the country's immense coal seams. As illustrated in Figure 12, three main gas markets have developed around these basins to supply the Australian market:

1. The **East Coast Gas Market** (ECGM) – refer Section 5 for an outline of the ECGM;
2. The **Northern Gas Market**, which was recently linked to the ECGM by means of the Northern Gas pipeline via Mt Isa from the Northern Territory; and
3. The **West Coast Gas Market**, which is independent of the others owing to the large distance between Western Australia's (predominantly offshore) basins and the Northern and Eastern Markets.

Existing pipeline infrastructure transports gas from production regions, predominantly Queensland, to the regions of high gas demand, such as Sydney, Melbourne and Adelaide. Although historically the southern basins contained large volumes of gas which was extracted relatively cheaply, most of these resources are now approaching depletion or have been depleted by decades of extraction.

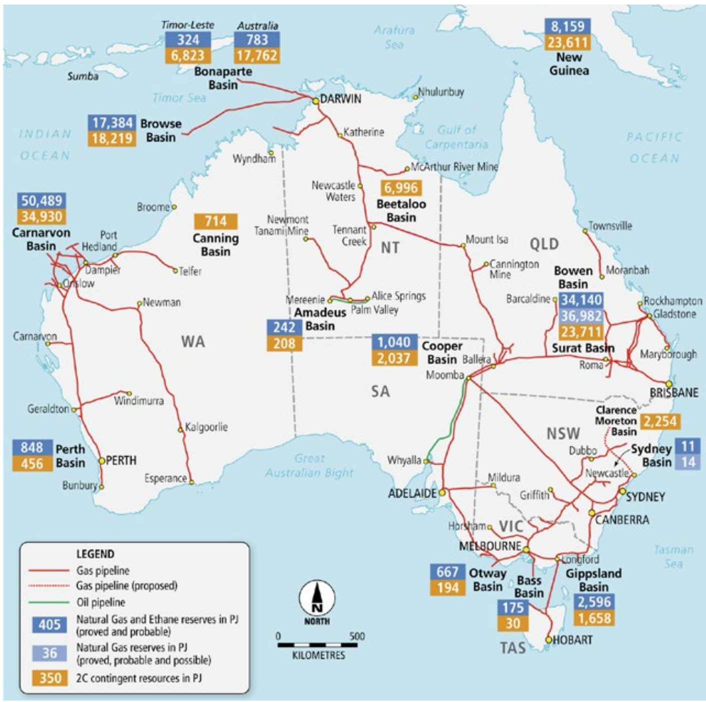


Figure 12 - Australian Reserves and Contingent Energy Resources 2019

(Source: Australian Energy Council 2019)

[2] JORC is the Australasian Code for Reporting of Exploration Results, Mineral Resources and Ore Reserves ('the JORC Code'). It provides a mandatory system for the classification of minerals Exploration Results, Mineral Resources and Ore Reserves according to the levels of confidence in geological knowledge and technical and economic considerations in public reports.

3.2 Gas basins reserves

Table 3 identifies Australia's 14 major gas basins and their proven and probable reserves. Historically, production of gas was centred in the southern basins of Otway & Gippsland, offshore Victoria and South Australia. In recent years, production from these basins has been in decline as reserves are increasingly depleted, whilst production from Queensland's Surat and Bowen Basins have been increasing as a result of large Coal Seam Gas (CSG) to Liquefied Natural Gas (LNG) projects in south-west Queensland.

Table 3 – Australia's gas basins – 2P reserves and 2C resources

(Source: Energy Council of Australia)

Basin	**2019 2P Reserves *(PJ)***	**2019 2C Contingent Resources *(PJ)***	**Basin development status**
Amadeus	242	208	Production
Bass	175	30	Production – Late Life
Beetaloo	0	6996	Early exploration
Bonaparte	783	17,762	Production
Browse	17,384	18,219	Production
Gunnedah	1,520	1,520	Undeveloped
Carnarvon	50,489	34,930	Production
Galilee	N/A	N/A	Undeveloped
Clarence Moreton	0	2,254	Undeveloped
Cooper	1,040	2,037	Production
Gippsland	2,596	1,658	Production – Late Life
Otway	667	194	Production – Late Life
Perth	848	456	Production
Surat / Bowen	36,982	23,711	Production (Surat) / Production & Appraisal (Bowen)
Sydney	14	0	Undeveloped
Total	**216,844**	**109,975**	

For the Northern Gas Market, the Bonaparte and Browse Basins comprise the largest gas supplies in their market at around 1,000 PJ and 17,000 PJ in 2P reserves respectively. These basins export gas as LNG to markets in Asia via onshore and offshore LNG liquefaction plants.

The ECGM is comparatively more complex than both the Western and Northern Markets. A number of natural gas basins (Surat/Bowen, Gippsland, Otway, Bass, Cooper and Sydney) provide natural gas to domestic demand centres, as well as LNG for export via liquefaction plants at Gladstone in Queensland. The ECGM is currently connected by pipelines to basins totalling 38,000 PJ in proven and probable reserves and over 70,000 PJ in estimates and contingent resources.

4. Global & domestic gas price forecasts

Natural gas is a tradeable commodity and over the longer term, its price will be determined by supply and demand conditions on global markets. Natural gas comes in various forms (e.g., at a basic level wet and dry gas) and competes with other fuel sources (coal, oil, nuclear, renewables etc.). While it is beyond the scope of this Study to consider gas in the context of the spectrum of fossil fuels, it is important to recognise that the prices of fossil fuels, particularly over longer time horizons, are linked because they are highly substitutable. Processing and transportation costs, as well as other technological constraints, introduce wedges between the prices of different hydrocarbons. These wedges are unlikely to change systematically over time unless there is a technological breakthrough that drives low production, processing and transportation costs.

Given that natural gas is a commodity tradeable on world markets, the market price of Australian-extracted gas is expected to converge to real world prices in the long run (the link between global and domestic energy prices is explored in more detail in Section 4.2.1). Forming a robust view about how the global energy market is expected to evolve over a long-run horizon is therefore an important requirement when assessing the economic viability of further unlocking the Bowen Basin.

The purpose of this section of the report is to identify a plausible range for the global price of natural gas over the next 30 years. The global energy market analysis then guides our domestic gas price forecasts by providing an anchor price on which cost-based adjustments can be made to determine a price specific to the local market.

4.1 Forecasting global gas prices

4.1.1 Our approach

This section outlines the approach to developing the demand scenarios. KPMG-Macro, a global macro-econometric model, has been used to support the analysis. Energy is an important input in the global production system. There is a strong relationship between economic growth and energy prices. Other things being equal, high energy prices increase production costs and slow down economic growth. Energy price shocks have disrupted economic activity over history, in some cases leading to recession and major dislocation. However, such shocks are, by their nature, largely unpredictable and temporary in nature. This analysis focusses on longer-term trends, abstracting from temporary supply or demand shocks in the energy market. This does not mean that the reactions of economies to short-run energy shocks are ignored. Energy shocks make businesses and governments focus on energy security and on energy efficiency, which can result in permanent changes in production technology and in energy supply.

In standard applications of KPMG-Macro, the supply side of the energy market is assumed to accommodate demand. Loosely speaking, growth in economic activity depends on, among other things, energy prices, which in turn depend on growth in economic activity. In this framework, faster economic growth tends to push up energy prices, which has a dampening effect on growth.

Over a longer horizon, the key drivers of **gas demand** will be:

- The price of gas relative to the price of substitute fuels (ranging from close substitutes through to not-so-close substitutes);
- Growth in economic activity, including the regional and industrial composition of growth;
- Technological change driving improvements in energy efficiency. This may be partially driven by policy settings; and

- Environmental and other policies designed to increase energy efficiency and change the energy mix.

Over a longer horizon, the key drivers of **gas supply** will be:

- The anticipated market price of gas; and
- Availability of reserves and the cost of extracting, processing and delivering the fuel to users relative to other fuel sources.

4.1.2 Energy market backdrop

Energy consumption is analysed through a prism of global growth, including the regional and industrial composition of growth and energy efficiency. We then consider how the energy mix has changed over time, focusing on how the share of fossil fuels in total energy usage has changed over time and how the mix of oil, gas and coal has changed within the fossil fuel bundle. On the supply side, we analyse how proven oil and gas reserves have changed over time and relate to production in various regions to reserves.

The historical analysis provides a useful context for understanding the projections reported below and the key underlying assumptions. The key relevant findings of the historical analysis can be summarised as follows:

- There is a close relationship between energy demand and global growth;
- Global production appears to have become steadily more energy efficient;
- Improvements in energy efficiency appear to have dominated any regional or industrial compositional changes in determining energy demand;
- Gas and non-fossil fuels have become a larger component of the energy mix over the historical period;
- Global energy reserves and technologies for commercially accessing these reserves have, together with the adoption of energy-saving technologies, generally allowed energy supply to accommodate demand, although there is evidence that over the decade between 2005 and 2015, the rapid growth in the world economy, and China in particular, put pressure on energy supply and, consequently, on energy prices;
- Increases in proven reserves of oil and gas, expansion in energy production, as well as energy transition activities and a saturated marketplace of energy providers, put downward pressure on energy prices in the years prior to the COVID-19 pandemic;
- Curtailment of global economic activity and mobility during COVID-19 pushed down global energy demand by 4.3% relative to 2019;
- The global economy has rebounded from depths of the contraction in the middle of 2020, where world GDP had declined by 7%. This rebound has been stronger than initially contemplated, and energy prices have followed - with crude oil and natural gas prices both now above their pre-pandemic levels; and
- The global transition towards renewable energy sources has picked up pace in recent years and has increasingly become a focus for policy makers. This topic is discussed in greater detail in Box 2 below.

In developing the future demand scenarios for gas demands and prices, views need to be formed about the persistence of the above relationships and trends.

Box 2: Global Energy Transition

A reduction in carbon dioxide emissions (and their equivalents) of approximately 3-6% per annum between now and 2050 is needed to limit global warming to 1.5-2°C (World Economic Forum, 2020). In response to this identified need for a reduction in carbon dioxide emissions, policy makers are increasingly focusing on transitioning to a carbon neutral future by skewing the energy mix in favour of renewable energy sources. During the transition period from a global economy reliant on energy generated by coal and oil to a global economy more reliant on sustainable energy production methods, natural gas is widely seen as a 'transition fuel' which provides higher carbon efficiency (i.e., less carbon dioxide is emitted per unit of energy output) than other fossil fuels.

As of June 2021, 131 countries have stated their intentions to be carbon neutral by 2050, but only a few countries have developed robust policies or frameworks to deliver on a net-zero ambition.

Long-term energy demand projections are regularly produced by various players in the energy market. These long-term energy demand projections vary considerably depending on underlying assumptions and methodologies, however for all but the most ambitious climate scenarios of those considered (i.e., BP's Rapid Transition scenario, Equinor's Renewal scenario and IEA's Sustainable Development scenario), projections show a steady rise in total energy demand out to the year 2040. It is worth noting that the pace at which energy demand increases over the forecast period has generally decreased compared to previously produced forecasts, in part due to the widespread adoption of evolving technological advancements designed to improve energy efficiency.

Global energy demand forecasts considered in Figure 13 below show that demand for coal is expected to decline (across most scenarios); liquids to grow (across most scenarios); natural gas to grow (across all scenarios); and renewables growing to rival and, in a small number of scenarios, surpass fossil fuel sources. The average share of fossils fuels in the energy mix in 2040 across all scenarios shown in Figure 13 below is 75%, with non-fossil fuels, such as nuclear and renewables, comprising the remaining 25%. Linearly extrapolated to 2050 (using 2015 and 2040 as reference points) this figure would be 72%.

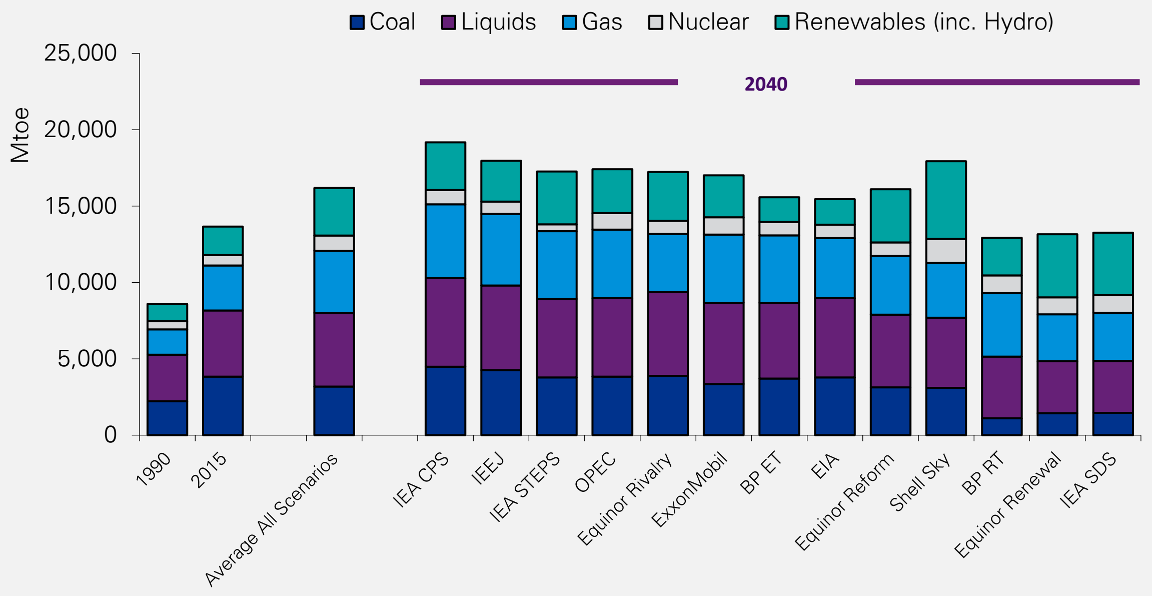


Figure 13 – Forecast global primary energy consumption by fuel type
(Source: KPMG analysis)

4.1.3 Future Demand Scenarios

Central global demand scenario

The central demand scenario is based on KPMG's current global macroeconomic forecasts for 2021 to 2050. Figure 14 shows KPMG's projections for real Gross World Product (GWP). The main feature of these forecasts is that global growth over the next 30 years is expected to be lower than that recorded in the previous 30 years.

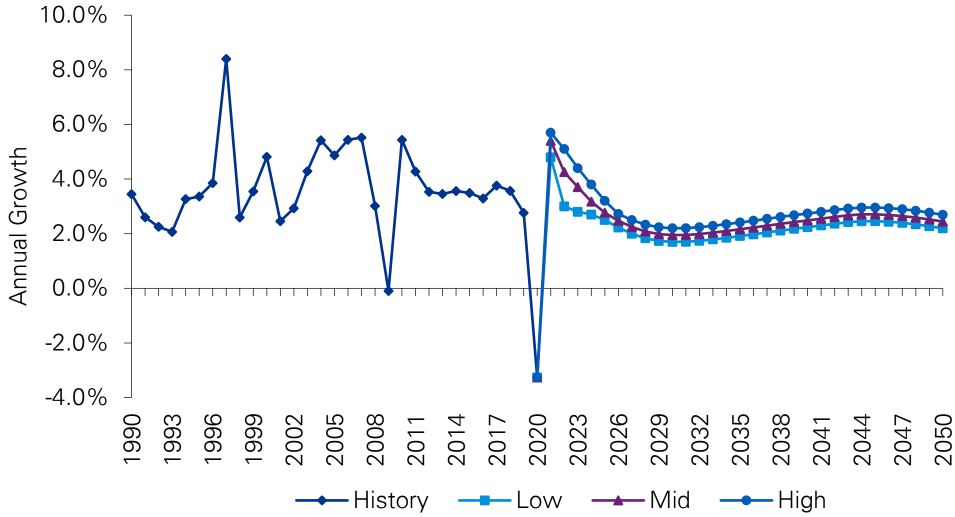


Figure 14 – KPMG-MACRO real Gross World Product forecast, 2021-2050

(Source: KPMG analysis)

It is also worth noting that, in our base case global macroeconomic forecasts, we do not have any major spurts of exceptional growth, analogous to the China experience in the recent past, for large developing economies such as Africa and India. While growth rates in these two regions are elevated over the forecast horizon, they are not assumed to accelerate during a rapid development phase before trailing off as they mature. Our maintained hypothesis is that the Chinese growth phenomenon will be difficult to replicate in other large, developing economies because they have very different political/economic systems.

Energy price shocks have disrupted economic activity over history, in some cases leading to recession and major dislocation. However, such shocks are, by their nature, largely unpredictable and temporary in nature. In developing the central demand scenario, we have incorporated the following key assumptions about the (i) industrial composition of the global economy; (ii) energy intensity of the economy; and (iii) share of fossil fuels in the energy mix. These assumptions are discussed in more detail below.

Industry composition of the economy

At the global level, the industrial composition of the global economy has not changed significantly in recent years. A small downward trend in industrial production as a share of GWP is evident between 1990 and 2020. In the central case scenario, we have assumed that the share of GWP accounted for by industrial production in 2050 falls to 16.4% in 2050, down from 26.5% in 2020 as illustrated in Figure 15. This assumption decreases the rate at which energy consumption increases for a given increase in global economic growth.

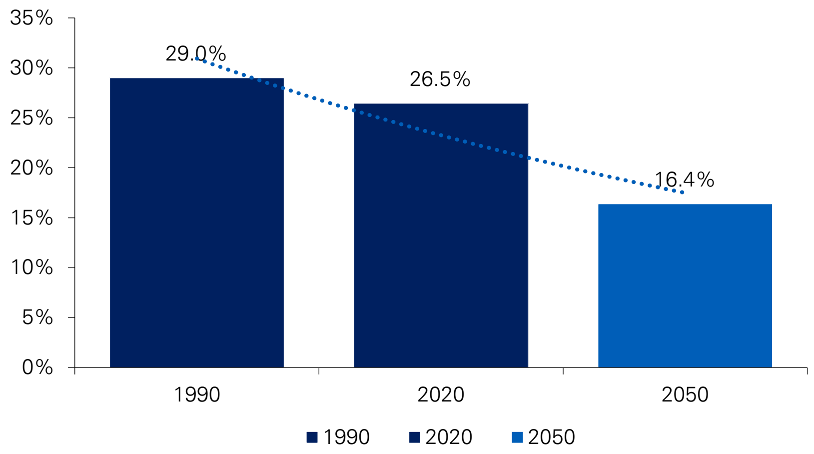


Figure 15 – Global trend: industry share of GWP
(Source: KPMG analysis)

Energy efficiency

At the global level, a downward trend in the energy intensity of global production is evident. Our central case has the current trajectory continuing. This implies that, in 2050 at the global level, 0.09kg of oil equivalent energy inputs are required to generate 1 real $USD of GWP (see Figure 16). This assumption reduces the rate at which energy consumption increases with global economic growth.

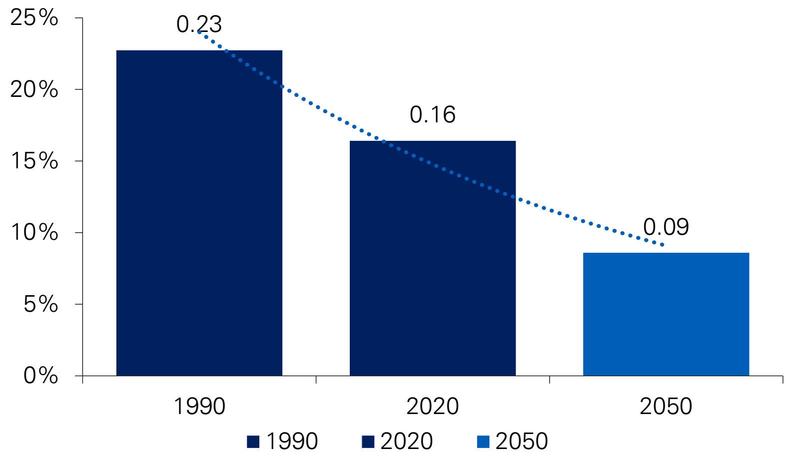


Figure 16 – Global trend: energy efficiency
(Source: KPMG analysis)

Share of fossil fuels in the energy mix

The share of fossil fuels in the energy mix is assumed to continue falling in the central case scenario, moving from its current level of 83% to 70% in 2050 (see Figure 17). This is five percentage points lower than the average forecasted share of fossil fuels in the energy mix in 2040 across a range of energy market commentators (refer to Box 2). This assumption reduces the rate at which fossil fuels are consumed (as energy consumers switch to non-fossil fuels).

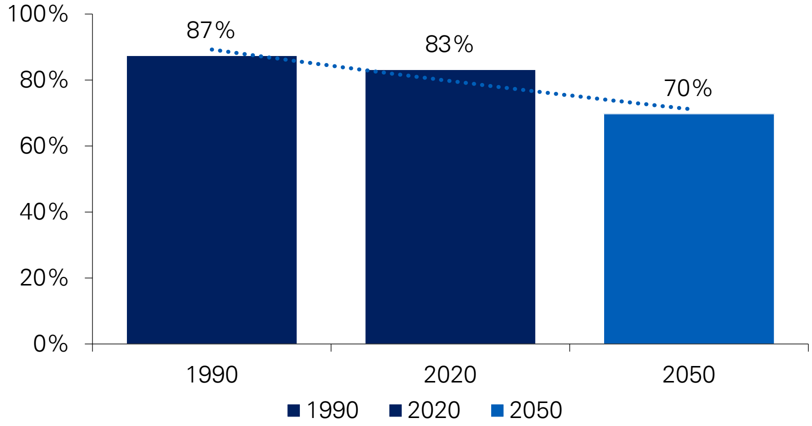


Figure 17 – Global Trend: share of fossil fuels in the energy mix
(Source: KPMG analysis)

These specific energy market assumptions, together with other assumptions embodied in KPMG's global macroeconomic forecasts, yield a central case projection for global energy demand. Figure 18 shows that we are forecasting global energy demand to increase from 13,295 Mtoe in 2020 to 18,960 Mtoe in 2045 (a 42% increase in aggregate energy demand).

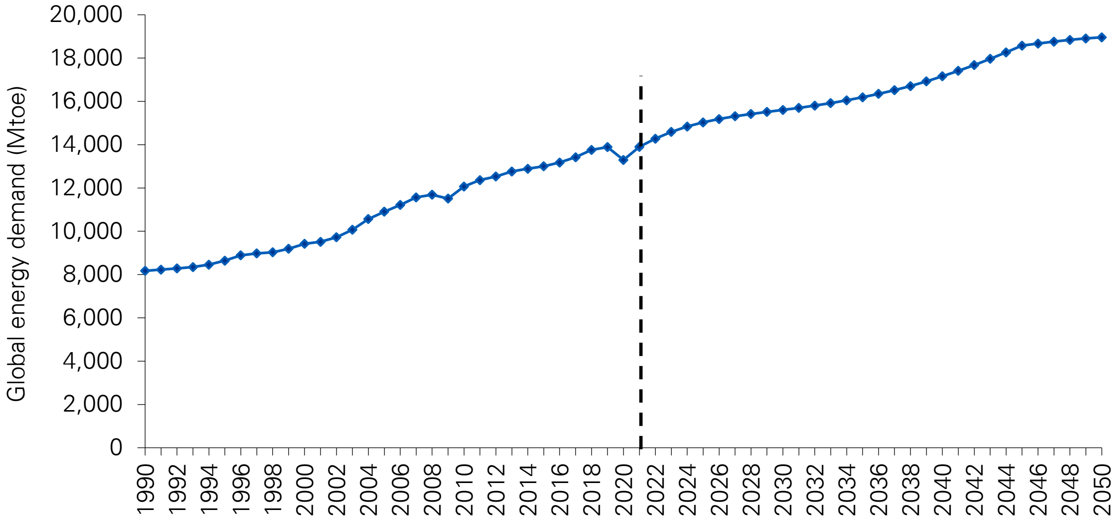


Figure 18 – Global demand for energy, 1990-2050
(Source: BP & KPMG analysis)

4.1.4 Alternative global demand scenarios

The central case scenario outlined above represents our best estimate of the expected outcome. However, we recognise that there are many alternative outcomes with reasonable likelihood of occurring. To give some guidance on the possible range of outcomes, we consider two alternative scenarios either side of our central case. We refer to these scenarios as "low" and "high".

Alternative scenarios have different settings for risk and global trade parameters designed to capture an economic environment, with higher risk and greater barriers to free trade in the low scenario and vice versa for the high scenario. Although the alternative scenarios have not been formulated in a formal probabilistic framework, we judge them to have reasonable likelihoods of occurring (i.e., we do not consider them to be in the tails of the distribution of possible outcomes).

4.1.5 Long run price projections

Figure 19 below shows our long run projections for a reference real (2020 dollars) Japan Korea Marker (JKM) price of LNG. In the central case, the real JKM price for LNG recovers from USD$4.40 per Mbtu in 2020 to around USD$8.80 per Mbtu in 2022. The price then declines to around USD$5.20 in 2026 before gradually rising to around USD$6.20 in 2050.

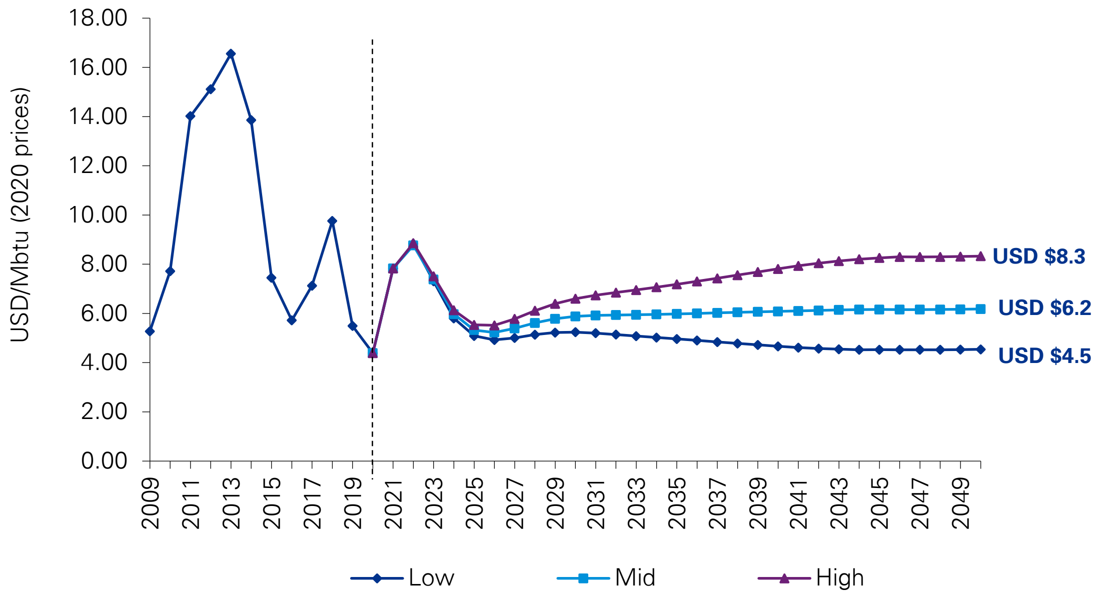


Figure 19 – Projections for the real price of LNG (Japan Korea Marker)
(Source: KPMG analysis)

In the central case, the real JKM price for LNG recovers from USD$4.39 per Mbtu in 2020 to around USD$8.77 per Mbtu in 2022. The price then declines to around USD$5.23 in 2026 before gradually rising to around USD$6.18 in 2050.

4.2 Forecasting domestic gas prices

4.2.1 The link between global and domestic energy prices

In 2019, Australia became the largest exporter of LNG in the world, with 88mtpa of installed LNG capacity. Key to achieving this milestone was the investment in liquefaction plants in Gladstone, on Australia's east coast, with a combined nameplate capacity of 24mtpa or 27% of Australia's total capacity. The establishment of LNG exports from Gladstone has linked the domestic market to international markets and influenced ECGM dynamics through pipeline flows and pricing.

Linking of the domestic gas market with the international LNG market has altered the market and pricing dynamics affecting the ECGM. By linking the Australian market to international buyers of LNG which often commands much higher prices, it has enabled the economic development of substantial volumes of high cost CSG. As a result, the ECGM has become closely linked with the dynamics of Asian LNG markets and their pricing instruments. This expansion of development to unconventional CSG resources, incentivised by the prospect of higher prices, has also improved the supply horizon or

Australian gas which was previously anticipated to deplete faster due to the lower estimates of economically recoverable gas prior to CSG development.

Asian LNG markets

The majority of Australia's LNG exports are sold into Asian markets, with China and Japan buying approximately 80% of LNG production, and South Korea and other northern Asian countries taking the remainder.

As LNG demand in Asia has continued to grow, more shipments have come into the region and prices have increasingly dislocated from the traditional benchmarks that included Brent crude. This has resulted in the emergence and use of the JKM LNG benchmark, a pricing instrument published by S&P Global Platts. JKM has quickly become the main pricing measure used in the Asian spot market.

As a result of the significant trade in Australian LNG against JKM in Asian markets, the benchmark has also become an increasingly important influence in Australia's domestic gas market dynamics.

Influence on the ECGM

At present, Australian LNG producers are the marginal suppliers of gas into the ECGM, and the price at which they would be willing to sell gas to domestic buyers influences the market price of gas domestically. The most likely destination for this gas (if not used to supply the ECGM) is the Asian LNG market. As such, domestic gas sales are increasingly linked to Asian LNG market pricing.

In theory, the LNG netback price is the price at which LNG exporters are indifferent between exporting LNG and supplying the domestic market as this is the price at which both markets are at parity. An LNG netback price is a measure of an export parity price that a gas supplier can expect to receive for exporting its gas. It is calculated by taking the price that could be received for LNG and subtracting or 'netting back' the costs incurred by the supplier to convert the gas to LNG and ship it to the destination port.

Under current market dynamics, LNG netback prices based on Asian LNG spot prices (i.e. Platts JKM) play an important role in influencing domestic gas prices in the ECGM. In addition, Queensland LNG producers entered a Heads of Agreement (HOA) with the Government where a commitment was made to offer gas to the domestic market on competitive terms before offering any uncontracted gas to the international market.

There has also been a positive correlation between the LNG netback price and ECGM domestic prices over the previous two years (Figure 20), although volatility in this convergence still exists as domestic gas prices have experienced a positive spread over JKM netback throughout 2019 and 2020 as LNG prices have fallen.

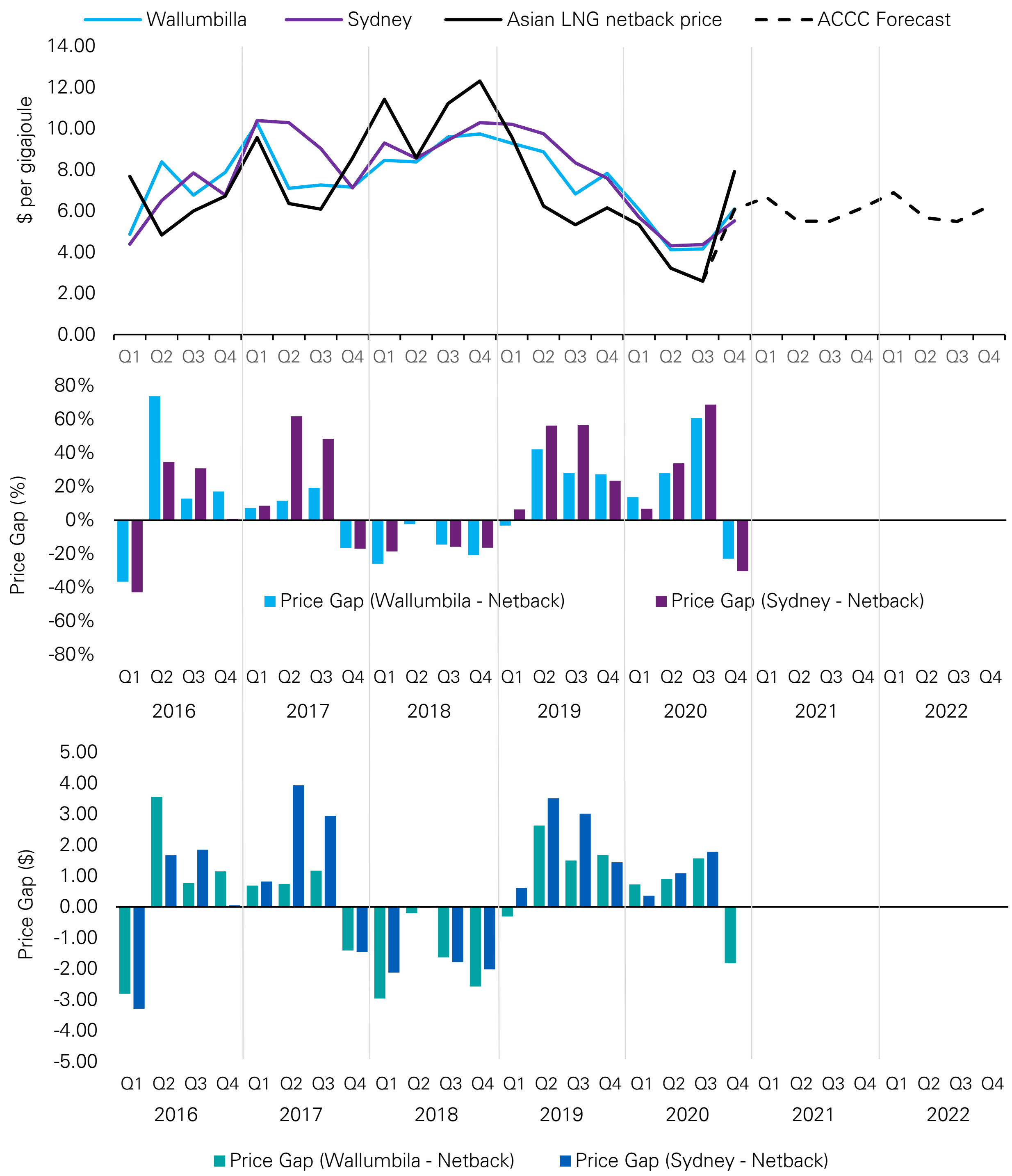


Figure 20 – Domestic spot price and Asian LNG netback price correlation

(Source: KPMG analysis)

An LNG netback price is not the sole factor that influences domestic prices in the ECGM. Individual prices paid by gas users will also reflect other factors that may be relevant to their circumstances, including the terms and conditions of their gas supply and any applicable transportation or retailer charges.

Notwithstanding this, domestic gas buyers in the ECGM are increasingly looking to JKM netback pricing as the benchmark for their domestic contracts, and this is also starting to emerge as a favoured benchmark by various levels of the Australian Government when setting domestic gas policy.

Calculating an LNG netback price

A short-run LNG netback price at a particular location is calculated by taking a delivered ex-ship (DES) LNG price and subtracting the cost of shipping the LNG from the loading port to the destination port, the short-run marginal cost of liquefaction, and the short-run marginal cost of transporting the gas from the relevant location to the LNG production facility.

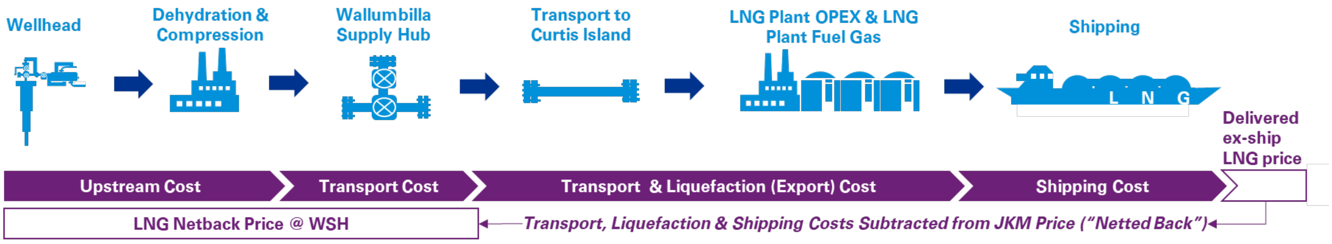


Figure 21 – Calculating an LNG netback price

(Source: KPMG analysis)

4.2.2 Australia's energy transition

Australia is not immune from the need to drive a low carbon energy future that is influencing global energy markets. An 11-14% emissions reduction below 2020 levels is required for Australia to meet the Paris Agreement, equivalent to 440 to 452 Mt CO2-e in 2030. Emissions for Australia in the year to December 2020 were 510 MtCO2-e, a 14% reduction on 1990 levels but <4% decline on 2018 levels. Given this trajectory, there is a need to drive further emissions reductions across the economy, and the pathways to achieve this are continuously evolving. Within this landscape, however, three broad trends have emerged in the energy sector that is shaping how energy will be delivered into the future.

It is important to consider these trends when assessing the potential pathways for development of the Bowen Basin, as they will influence the demand for the Basin's gas, the ability to finance development and the role of gas in the future energy mix.

Trend 1 – A decarbonisation journey, with the rise of renewables as the new baseload generation

Renewable energy generation has increased as a share of total Queensland generation from almost zero to more than 15% in the last decade. During this same period, gas powered generation has declined considerably as a result of both increasing Variable Renewable Energy (VRE) penetration and coal fired power generation remaining in the generation mix.

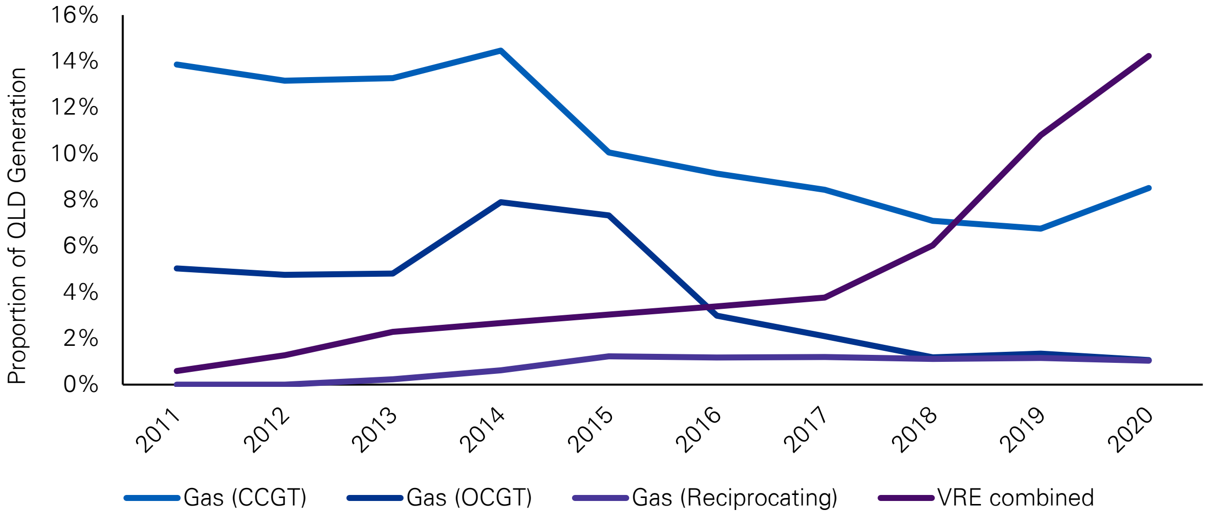


Figure 22 – Share of total Queensland generation – gas vs. renewables (2011 – 2020)
(Source: KPMG analysis)

Trend 2 – An increasing need for a combination of storage solutions to address intermittency

As renewable penetration increases, there is forecast to be a large uptake in storage technologies, both for grid-scale and behind-the-meter distributed batteries. This large increase in storage capacity is required to address the inherent intermittency of renewable energy generation.

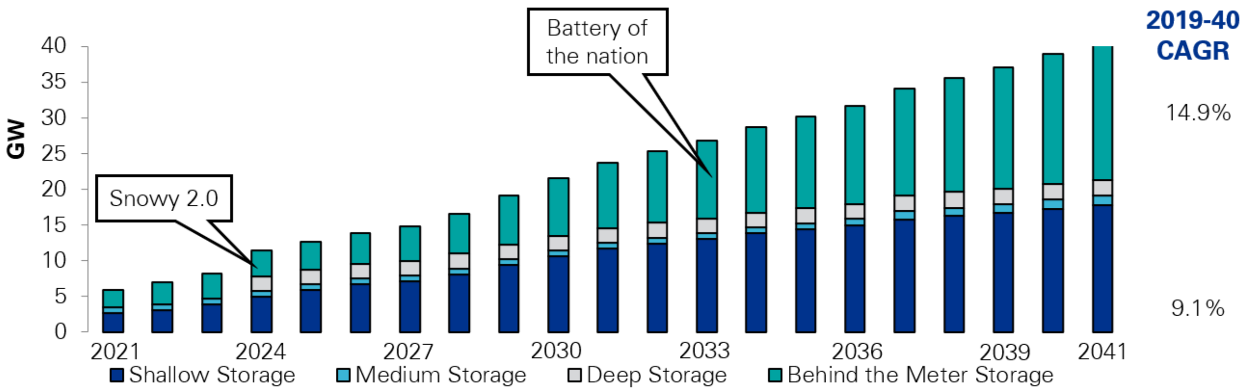


Figure 23 – Storage development outlook (2021 – 2041)
(Source: KPMG analysis)

Trend 3 – Increasing difficulty in obtaining traditional corporate and project financing for fossil fuel companies, combined with activist investor pressures

Traditional sources of finance and insurance for resources projects are pivoting away from fossil fuels. Large insurers, asset managers and investment banks are committing to exit positions that generate revenue from coal, oil and natural gas, making it increasingly difficult for energy companies to finance new projects.

Corporates	Insurers	Institutional Investors	Asset Owners
Orsted financing through Green Bonds, PE Firms actively invested stake through IPO	Major insurers are turning away from brown energy	Refocusing away from carbon-intensive energy finance	BlackRock to drop companies that derived 25% or more of revenue from coal production

Figure 24 – Positions of major energy industry participants on ESG
(Source: KPMG analysis)

4.2.3 Domestic price projections

KPMG's forecast long run real price for LNG (JKM Price) in the mid-scenario is USD$6.20/MMBtu, equivalent to AUD$8.35/GJ (depending on the exchange rate). Using the ACCC methodology to calculate Netback at Wallumbilla, our expectation is a long-run Wallumbilla Supply Hub Netback price of approximately AUD$7.00 to $7.50/GJ.

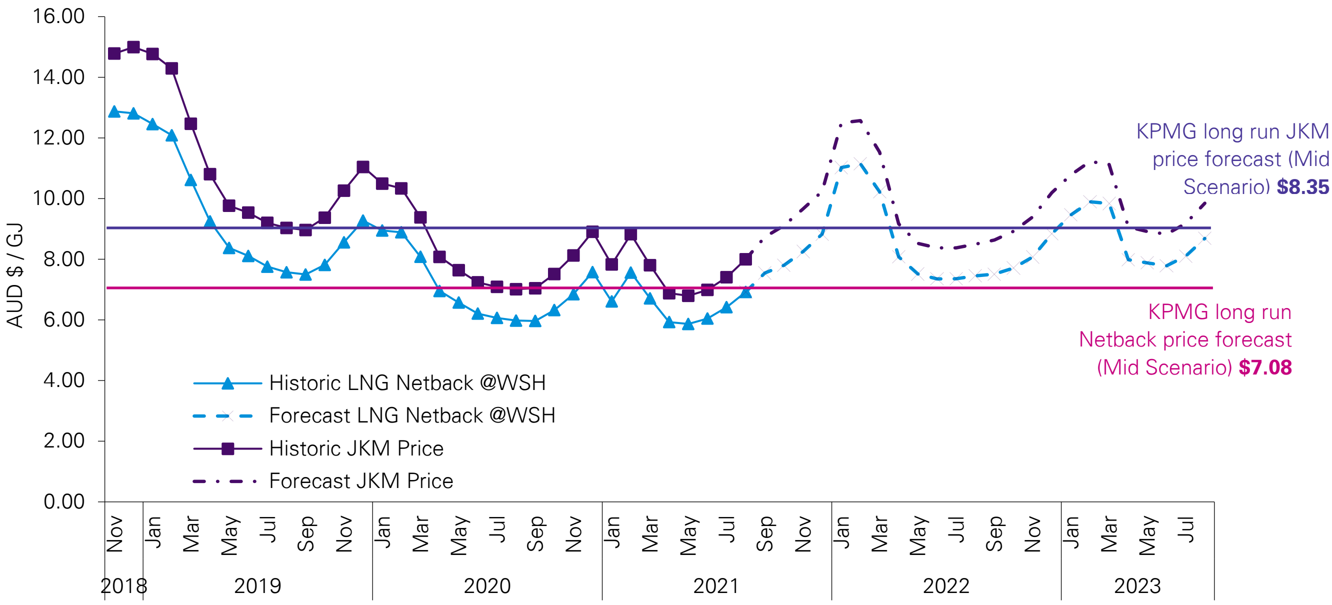


Figure 25 – Historic & forecast JKM and Netback (WSH) gas prices
(Source: KPMG analysis)

Volatility will exist in these prices depending on settlement dates for various delivery dates, demand and supply dynamics, short-term market events and other factors. However, using this price point as a guide, it is possible to analyse the economic viability and recoverability of gas from the Bowen Basin using a range of modelling scenarios.

4.2.4 Commentary on the long-run netback price

The long-run forecast JKM LNG price presented in this report is an average projected price based on long-run drivers of gas demand globally. Short term, and potentially medium term, JKM prices will fluctuate based on short term market conditions, which historically have included Northern Hemisphere winter weather fluctuations, liquefaction plant shut-downs due to maintenance or damage, shipping constraints and gas storage inventory changes. Over the long term, these short-run increases or decreases in JKM LNG prices mean-revert to the fundamental long-term supply and demand dynamics of the market.

The netback price calculated at the Wallumbilla Supply Hub based on the long-run JKM LNG price generally sets a floor for gas prices within the ECGM, although short-term volatility means that prices fluctuate above and below the netback in the short term. The netback price point of approximately AUD$7.00 to $7.50 / GJ at Wallumbilla that has been calculated as part of this Study is considered a reasonable middle-point for the long-term gas price for the ECGM (under balanced ECGM supply and demand conditions), although short-term fluctuations will occur due to short-term market dynamics. Where supply is tight, the ECGM prices will be elevated, with the GSOO predicting tight supply conditions to persist in the near to medium term.

The analysis was also conducted using a low-point forecast of AUD$5.00/GJ and a high-point forecast of $9.00/GJ to test the sensitivity of economics with a wider range of gas prices. Section 7.2 provides an economic production matrix for all three gas prices, where various well type curves have been modelled for each.

As a base case scenario, the AUD$7.00/GJ central price forecast has been used to test the economic viability of the Bowen Basin development, as it provides a reasonable and realistic assessment of economic recovery.

Box 3: What do we mean by gas price?

The gas prices provided in this report are wellhead prices, and do not include transport to Wallumbilla, as the pipeline route, length, size, capacity, utilisation and contracting model is not known at this time. Estimates of a potential tariff for transport of gas from the Basin vary considerably depending on utilisation of the pipeline, contract durations, volumes and types. A reasonable estimate of a transport tariff from the Basin to Wallumbilla is in the range of $0.70 to $1.20. At this concept stage, given the accuracy of forecast prices and the level of unknowns in the commercial model this pipeline may take, the wellhead price of $7.00/GJ is considered reasonable when compared against a mid-point range of $7.00 to $7.50/GJ at Wallumbilla, depending on exchange rates and other factors. A key next step for understanding the potential of the Basin in more detail would be to develop a detailed commercial model to analyse the potential transport tariff considering the above variables.

5. Domestic energy market

As described in Section 3, Australia's domestic gas infrastructure can be grouped into three main gas markets:

- The ECGM;
- The Northern Gas; and
- The West Coast Gas Market.

The Bowen Basin is not connected to any of these gas markets with existing infrastructure, however it is located immediately north of the ECGM, which connects the Surat Basin in the north all the way to Tasmania in the south. Given its proximity, the Bowen Basin's likely source of market demand for gas will be the ECGM, and so the analysis of supply, demand, transport, price and competition has been focused on this market only.

5.1 The East Coast Gas Market

As illustrated in Figure 26, an interconnected gas grid connects Australia's eastern, northern and southern states. This market has undergone structural change as the gas industry has developed, particularly in Queensland. Amid emergence of southern state supply decline, this has resulted in changes to the direction of pipeline flows, the supply/demand balance and gas contract prices.

The ECGM has evolved from separate state-based markets, each served by a single basin and a single transmission pipeline. Over the past 20 years, new pipeline investment has connected these markets, making it possible for bi-directional transport of gas between Queensland and the southern states.

This interconnected network expanded further in 2018 with the opening of the 622km Northern Gas Pipeline, linking Tennant Creek in the Northern Territory with Mount Isa in Queensland. This new pipeline allowed the ECGM to source gas from the Bonaparte Basin in the Timor Sea, as well as onshore shale gas developments. The development of Queensland's LNG industry has further transformed the ECGM by giving producers the added option of exporting their gas offshore.

The ECGM can be thought of in terms of two dominant markets – northern and southern. The northern market encompasses all of Queensland through to Moomba in South Australia, while the southern market encompasses Adelaide, Sydney, and the Declared Wholesale Gas Market in Victoria. Prices in the northern and southern markets are generally distinct from each other, driven by varying physical and market dynamics:

- The market is physically dispersed and does not have a dense network of pipelines. Gas flowing from Queensland is transported via several transmission pipelines which adds cost and can act as a bottleneck;
- There are various trading points along the east coast, including Wallumbilla and Moomba, which allow for the use of gas swaps to avoid these transport challenges;
- A depletion of cheap gas reserves from southern fields, such as the Gippsland and Otway Basins, has resulted in 80% to 90% net-south gas flows per year since 2018; and
- The increasing trend of gas flowing from producers in the north to consumers in the south has resulted in the need for additional investment in mid-stream infrastructure. This includes increasing pipeline capacities (particularly the South West Queensland Pipeline (SWQP) and Moomba Sydney Pipeline (MSP), and the potential use of LNG import terminals to supply gas to southern states, especially during peak demand periods over winter.

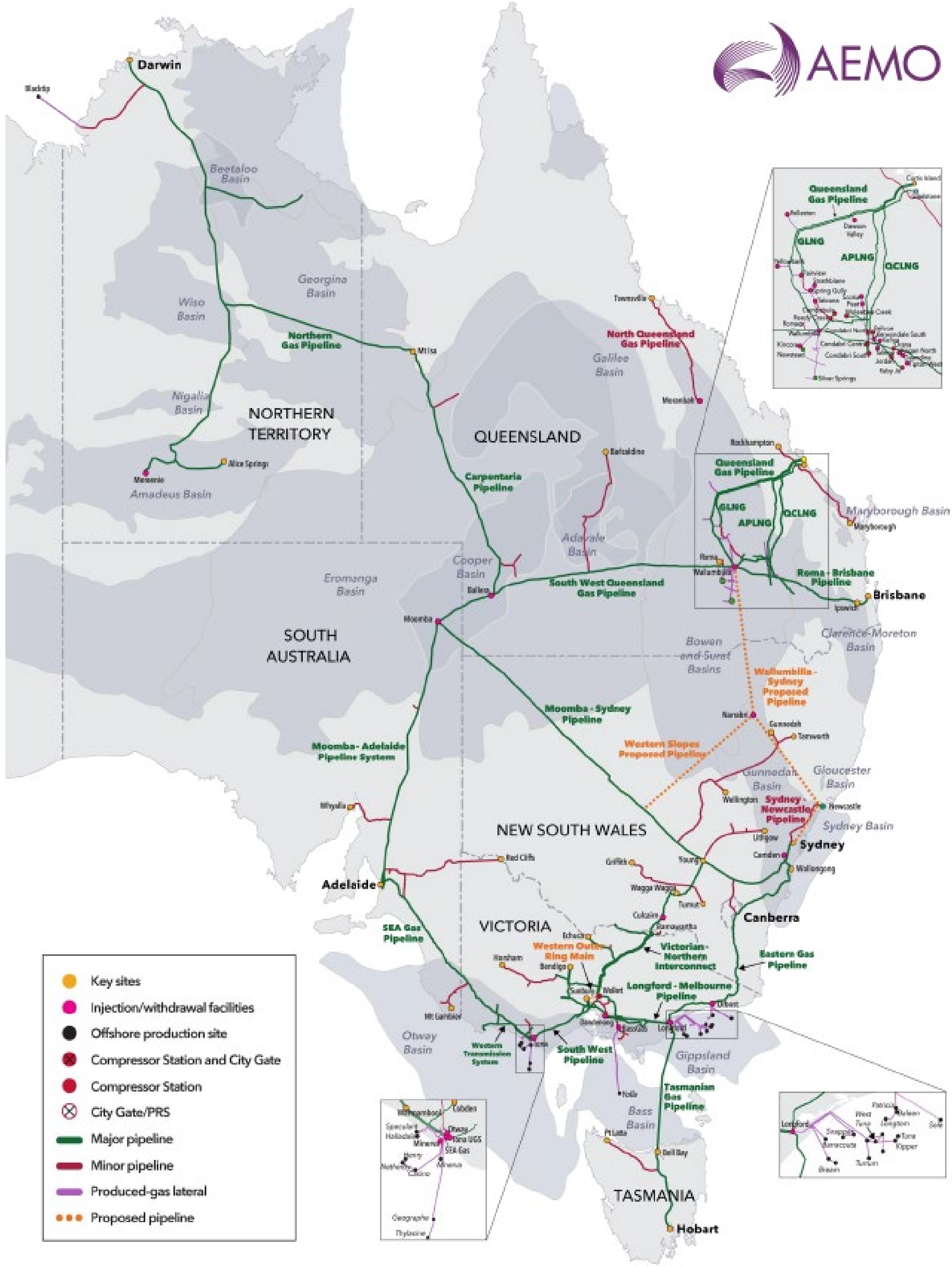


Figure 26 – Australia's East Coast Gas Market infrastructure

(Source: Australian Energy Market Operator (AEMO))

5.2 Gas demand

The demand for gas in the ECGM is driven by four main buyers of gas, which can be categorised into consumers of gas to export LNG, and domestic consumers who use the gas within Australia:

1. LNG exporters; and
2. Domestic consumers:
   a. Commercial & industrial (C&I) businesses;
   b. Electricity generators (GPG); and
   c. Households (Res).

Figure 27 shows that, while LNG export is the largest consumer of east coast gas, domestic demand is still considerable – domestic customers in eastern Australia consumed approximately 600PJ of gas in 2021.

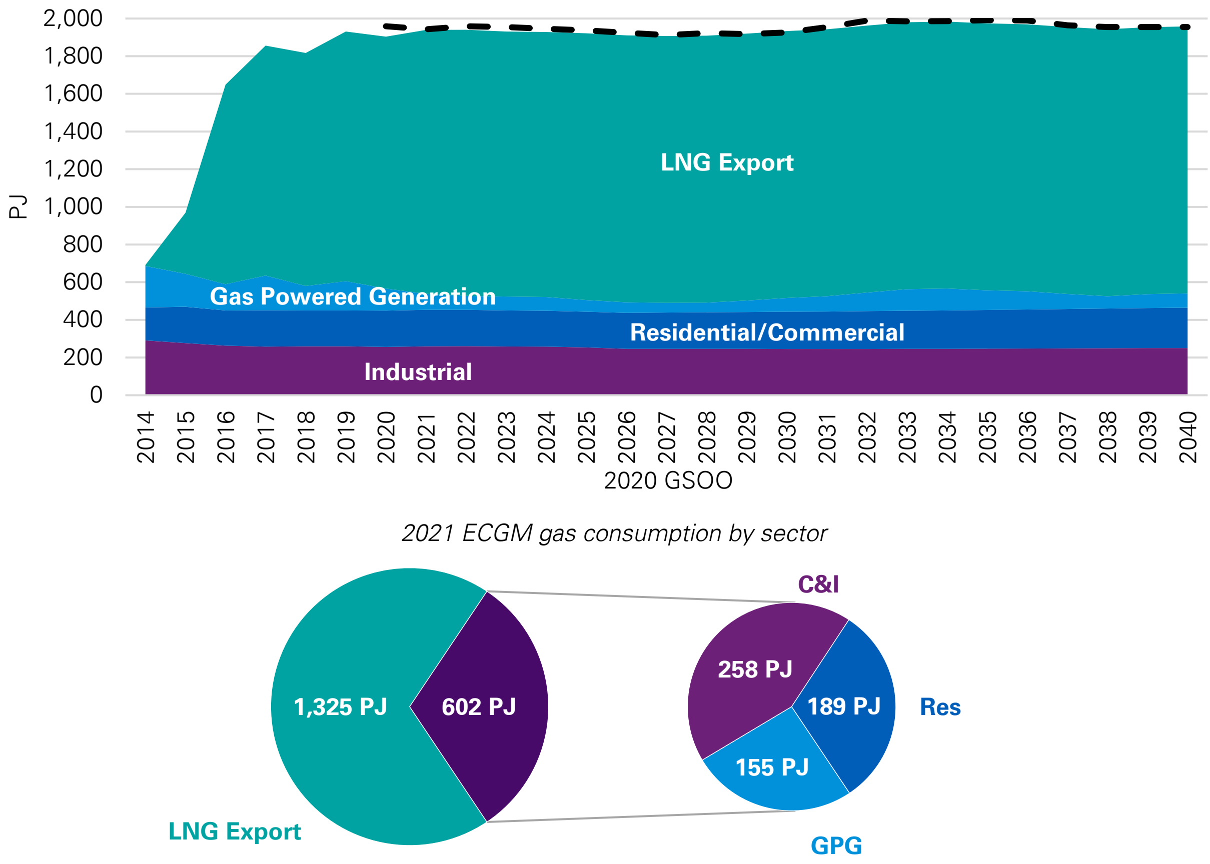


Figure 27 – Historic & forecast demand for gas in the ECGM
(Source: AEMO & KPMG analysis)

5.2.1 Demand from LNG exporters

The development of Queensland's LNG industry has transformed the eastern Australian gas markets by giving producers the added option of exporting their gas offshore. In 2019, Australia became the largest exporter of LNG in the world with 88mtpa of installed LNG capacity. Key to achieving this milestone was the investment in liquefaction plants in Gladstone, on Australia's east coast, with a combined nameplate capacity of 24mtpa or 27% of Australia's total capacity. The establishment of LNG exports from Gladstone has linked the domestic market to international markets and influenced ECGM dynamics through pipeline flows and pricing.

The liquefaction plants in Gladstone consume a combined 1,300 to 1,500PJ of gas per annum, representing approximately two-thirds of all gas demand in the ECGM. This considerable demand volume means that LNG exporters have considerable influence in the market from both a supply and demand perspective.

Linking of the domestic gas market with the international LNG market has changed how the gas price is set for ECGM participants. It has created opportunities for gas producers to sell gas for export, and for gas buyers to purchase gas that would otherwise be exported. As a result, Australia's East Coast Domestic Market has become closely linked with the dynamics of Asian LNG markets and their pricing instruments.

The three liquefaction plants in Gladstone are Australia Pacific LNG (APLNG), operated by Origin and ConocoPhillips, Gladstone LNG (GLNG), operated by Santos and Queensland Curtis LNG (QCLNG), operated by Shell.

The Origin and ConocoPhillips-operated APLNG project commenced exports in 2016 with 9mmtpa nameplate capacity. The plant consumes gas from Origin Energy's acreage in the Surat Basin and, beyond upstream expansion to backfill the trains, no expansions in export capacity are planned.

The Santos-operated Gladstone LNG project has been operating since 2015 and has a nameplate capacity of 7.8mmtpa LNG. Gas is sourced from the Surat and Bowen regions. There are several minor planned expansions of the GLNG project designed to extend its operational life, but no expansion of export capacity is planned.

The Shell-operated QCLNG project was initially designed to produce 8.5mmpta LNG, with potential expansion of up to 12mmpta after further development. This expansion is not anticipated to take place and, similar to the other two projects, development is limited to expansion of upstream gas supply.

It is essential for each of the three LNG plants to meet contractual LNG cargo schedules and volumes using the upstream gas extracted from the Surat and southern Bowen Basins. Beyond this, opportunities exist for LNG exporters to ship additional spot or uncontracted cargos of LNG, however this is now governed by the requirements of the HoA signed with the Federal Government and the Australian Domestic Gas Security Mechanism (ADGSM). Both require LNG exporters to offer gas in excess of contractual volumes to the domestic market before being permitted to export it as LNG.

Global demand for LNG

LNG demand is expected to grow faster than overall natural gas consumption as global trade increases to connect regions of highest supply and demand. However, even after substantial postponements of planned Final Investment Decisions (FIDs) during the oil price crash and pandemic of 2020, there is still a risk of new LNG supply outpacing growth in the mid-2020s (Figure 28).

Mainland China is expected to be the largest single market of new LNG demand, but new and emerging importers are a significant source of long-term import growth, particularly in south and southeast Asia.

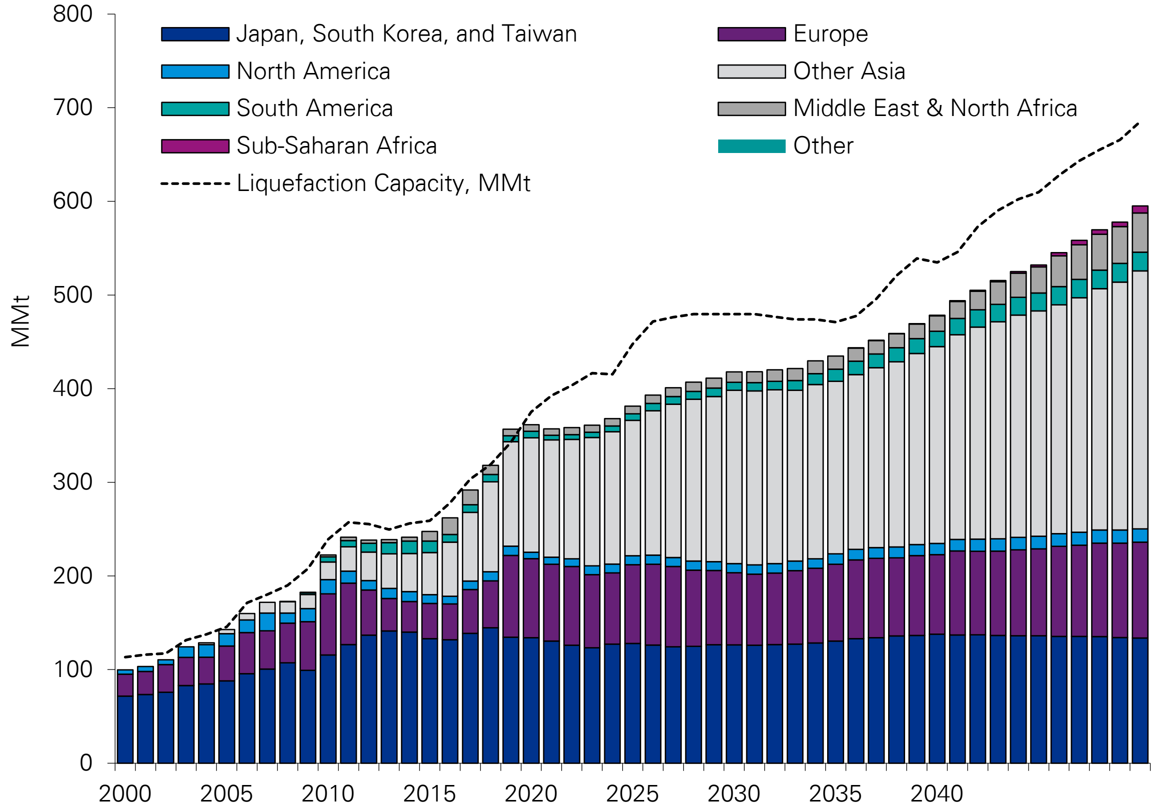


Figure 28 – Forecast global LNG demand

(Source: IHS Markit)

China

Coal-to-gas switching activity lessened in 2019 as the focus was shifted to economic growth. Near-term LNG import growth in mainland China is expected to be dampened by the impact of COVID-19 and reduced fossil fuel consumption by approximately 25% in the country. China has pledged to reach net zero emissions by 2060, however it is still aiming to peak its emissions by 2030 and, coupled with an administrative and policy support for gas, and little to no local supply, China will certainly be a large LNG importer over at least the coming decade.

Japan

LNG demand is expected to decline over the rest of the decade due to Japan's decarbonisation pledges which have been increased to a commitment to reduce greenhouse emissions by 46% from 2013 levels by 2030. This will no doubt impact any demand for gas as well as incentivise Japanese businesses to invest in alternative energy sources rather than bolster existing gas infrastructure.

South Korea

Although the low cost of coal and nuclear make them strong competitors to gas in South Korea's near-term power mix, South Korean annual gas demand is still higher than Australia's at 2,070 PJ in 2020 and is forecast to increase. The Government's plan to reduce South Korea's long-term reliance on nuclear and coal-fired generation will support LNG demand and their currently unachievable decarbonisation targets will likely have little impact.

Impact on ECGM LNG export volumes

Currently there are no LNG export projects proposed, anticipated or under development in the ECGM beyond the existing three plants. Anticipated development projects involve expanding the upstream gas supply to backfill these plants only, without any additional export capacity (and thus total demand for gas) being added.

The growth in global LNG demand outlined previously is expected to be met by greenfield developments and brownfield expansions, such as Qatar's North Dome expansion, as well projects in the USA and Russia. For the east coast LNG producers of Australia, this means continued exports of approximately 1,400 to 1,500PJ of gas annually into the future (Figure 29).

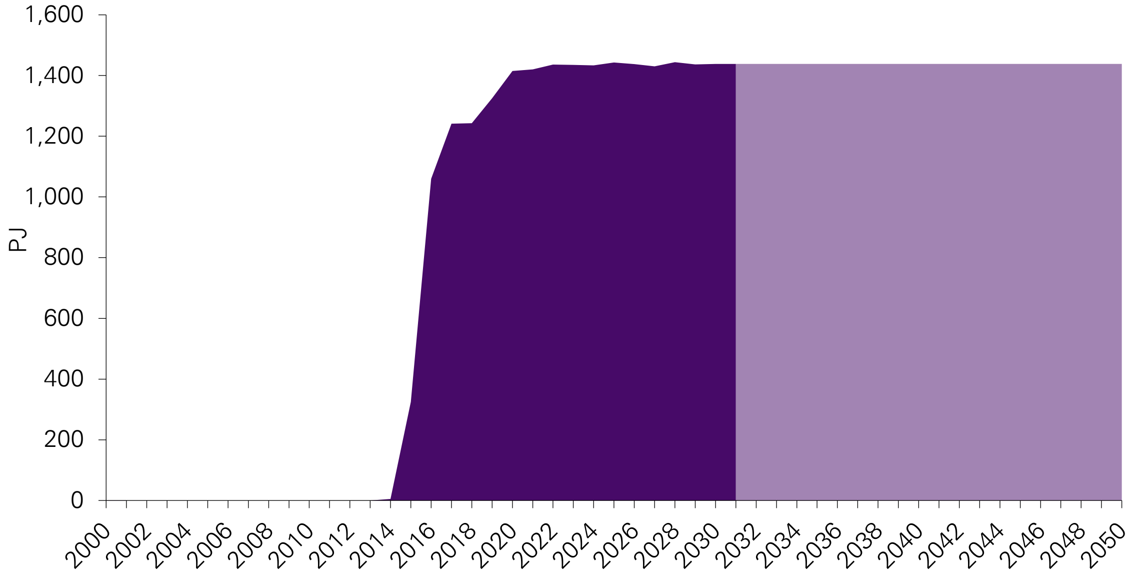


Figure 29 – Forecast LNG export gas demand (ECGM)
(Source: AEMO & KPMG analysis)

5.2.2 Demand from domestic users

Excluding LNG, C&I customers are the largest market for domestic gas – consuming 41% of gas sold to the domestic market, where it is used as an input to manufacturing. The electricity sector is another major consumer, using gas to fuel generators. Gas Powered Generation (GPG) accounted for 29% of domestic gas sales, with the remaining 30% sold to residential and minor commercial customers.

AEMO forecasts a period of relatively flat demand for natural gas in the ECGM across the medium to long term, following a period of decline from 2010 (Figure 30). Driving this flat forecast is a lower long-term outlook for GPG based on projections of growing distributed renewable energy generation. Challenging economics faced by Australia's industrial gas users means demand in the C&I sector is also projected to be flat. In the residential sector, new gas connections are likely to be offset by increasing efficiency and fuel switching away from gas appliances to electricity.

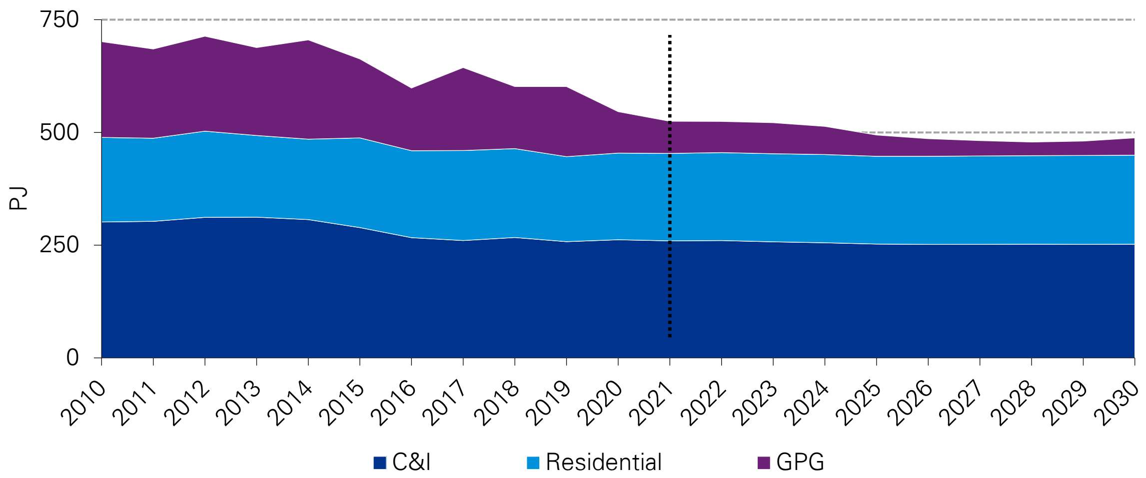


Figure 30 – Historic & forecast domestic consumer gas demand in the ECGM

(Source: AEMO & KPMG analysis)

Whilst the forecast is for aggregate demand for gas in the ECGM to remain flat, the composition of this demand and its position in the market will continue to evolve. This will likely become evident through increases in uncontracted demand positions and the desire to re-contract through shorter term contracts, leveraging more flexible products in order for customers to respond to uncertainty in their downstream market.

Table 4 – Demand forecast, drivers and preferences by sector

(Source: KPMG analysis)

Sector	Demand forecast	Drivers	Product Preferences
Commercial & Industrial	FLAT	▪ Price ▪ Energy efficiency ▪ Demand for end products	▪ Longer term contracts ▪ Stable pricing ▪ Lower need for flexibility
Gas Power Generation	LOWER	▪ Lower demand for centralised electricity generation ▪ Increasingly peaking to backfill renewable volatility ▪ Weather-dependent	▪ Highly flexible supply ▪ Rapid response times driven by weather-dependent peaking
Residential	FLAT	▪ Continuing and new energy efficiency schemes ▪ Fuel switching away from gas appliances	▪ Highly reliable supply

Forecast demand by market

Whilst the ECGM is considered a single market, the dynamics of each state within this market vary. In South Australia, electricity generation accounts for 50% of gas demand. Industrial demand from medium to large industrials (>0.5PJ/a) dominates in Queensland, while industrial and residential demand are roughly equal as the main components in NSW. Victoria is the only state where a majority of demand (62%) is from small residential and commercial customers, who use gas mostly for heating and cooking. Over 80% of Victorian households are connected to a gas network, which is a legacy from the development of the Bass Strait oil and gas fields.

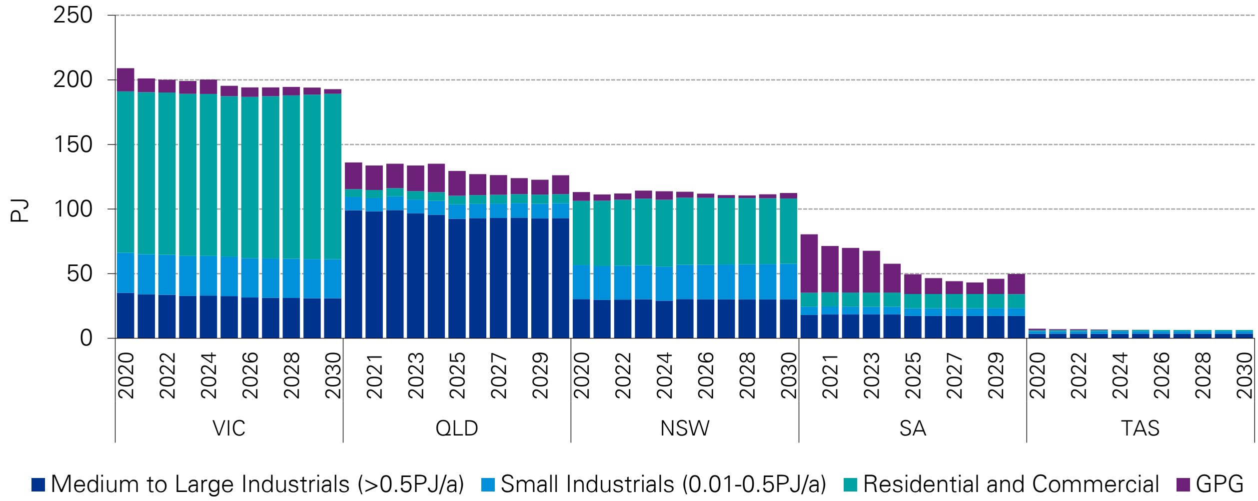


Figure 31 – Gas Demand Breakdown by State
(Source: AEMO & KPMG analysis)

Demand for gas is highest in Victoria, which is both increasingly reliant on northern gas supplies and is the most difficult market to access given physical and contractual transport bottlenecks. As such, obtaining firm capacity in key transport pipelines that link production to key hubs in Victoria will be an important competitive advantage to supply this market into the future.

5.2.3 The Northern Queensland gas market

The North Queensland Gas Pipeline (NQGP), also known as the Moranbah to Townsville Gas Pipeline, is a transmission pipeline located in north-east Queensland (Figure 32). The NQGP supplies gas from the Moranbah gas processing plant to large industrial customers in Townsville, such as the Yabulu gas fired power station and the Queensland nickel and copper refineries. The gas is sourced from coal seam gas fields in the Bowen Basin which are located near Moranbah and are jointly owned by AGL and Arrow Energy.

Demand for gas from the NQGP has been declining as power prices are increasingly pressured by competing renewable generation. Whilst the NQGP has a capacity of 108TJ/d, the pipeline is, on average, only flowing approximately 30TJ/d of gas from the Moranbah Gas Project.

The commercial viability of the NQGP is further challenged by the fact that it is an islanded system. This increases the need for longer term Gas Supply Agreements (GSAs) with consumers to underpin continued economic operation of the pipeline. However, trends in recent years have been for shorter GSAs, with buyers unwilling to take on the risk of long-term exposure given the volatility in gas prices that has existed since 2016.

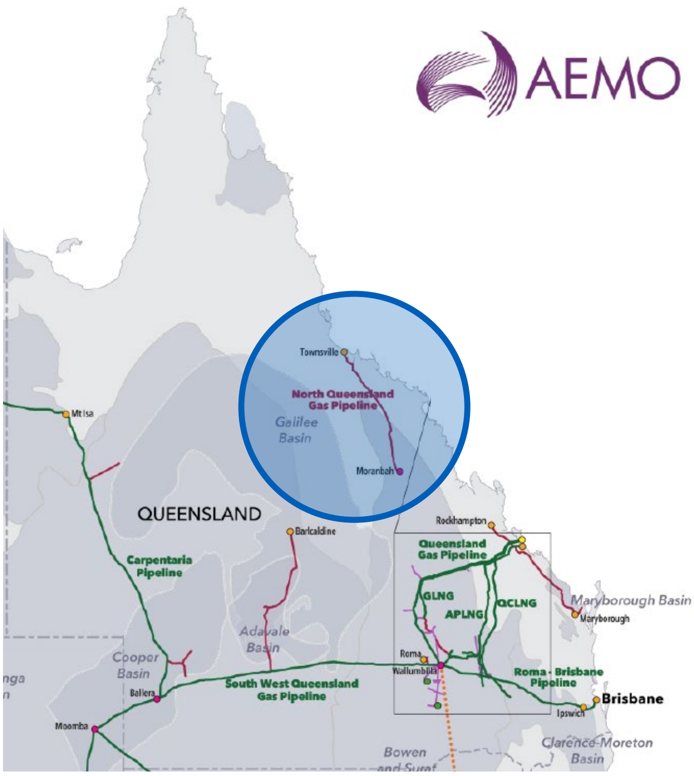


Figure 32 – North Queensland gas market infrastructure
(Source: AEMO)

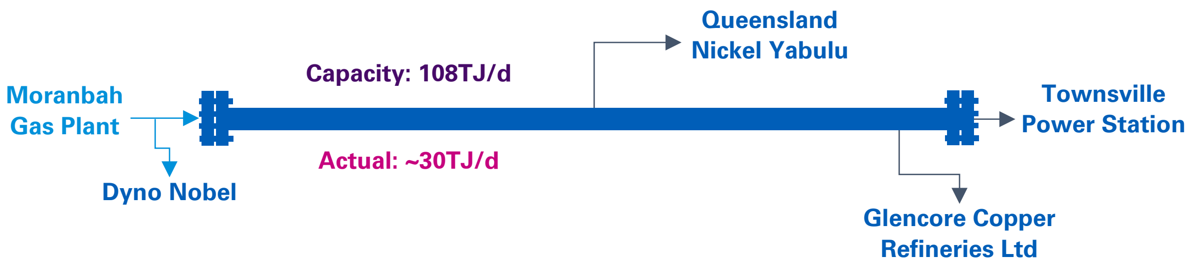


Figure 33 – Current state of gas supply & offtake – NQGP
(Source: KPMG analysis)

There is potential to stimulate demand to the north of the Bowen Basin, either by increasing the demand for gas fired power from existing power stations, or by growing demand from large industrial users. Such increases are likely to contribute modest growth in gas production in the Bowen Basin, potentially between 30TJ/d to 60TJ/d, however it is unlikely to be sufficient to underpin a full-scale development of the Bowen Basin as a whole.

5.2.4 Hydrogen and its effects on gas demand

Domestic commercial demand for hydrogen is expected to grow significantly in the late 2020s, reaching >1Mtpa in each of Victoria, Queensland and South Australia by 2036 (graph below). Victoria and Queensland are forecast to be the largest consumers of hydrogen resources, with Victoria taking the lead at 1.5 Mt of hydrogen consumption by 2038 (Figure 34).

Importantly, these two states are currently the largest consumers of natural gas (Queensland with LNG and Victoria with residential and commercial customers). As such, it is expected that growth in commercially viable hydrogen at scale will have an effect on the demand for natural gas in the ECGM. This growth is highly prospective however, as currently there is no hydrogen consumed in the ECGM and the technology is still in nascent trial phases.

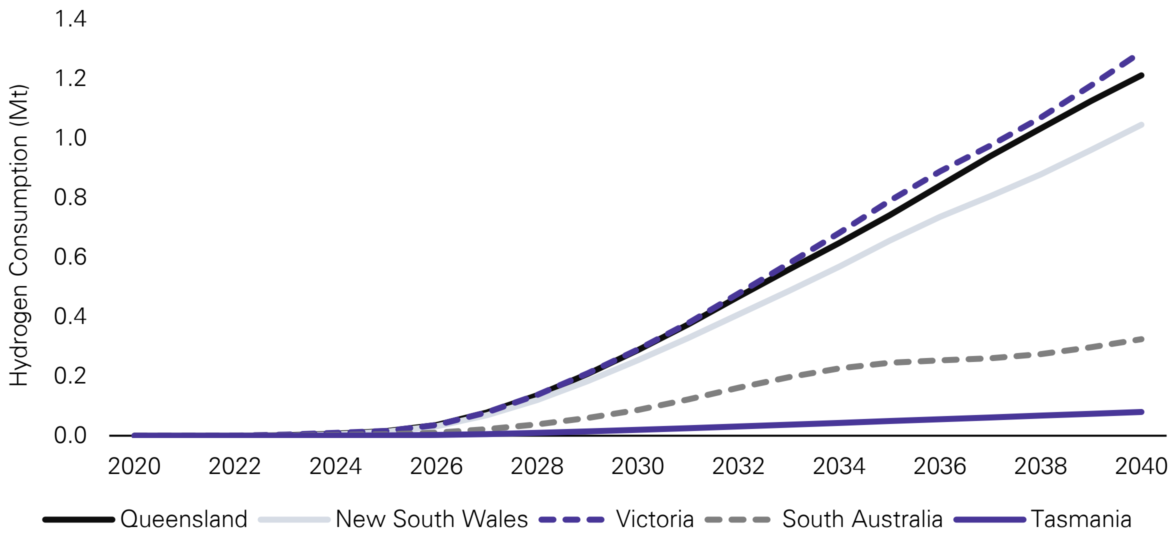


Figure 34 – Forecast demand for hydrogen in the ECGM
(Source: AEMO & KPMG analysis)

Queensland has over AUD$20Bn committed to development of renewable energies, and by 2030 Queensland has pledged to be Australia's leading hydrogen producing state. Hydrogen is expected to grow to as much as 100PJ out of the ECGM's approximately 600PJ annual domestic consumer demand for gas (Figure 35). This is driven by fuel blending (hydrogen with natural gas), fuel switching (burning hydrogen as a primary fuel source) and industrial consumption of hydrogen as a production input.

Industrial hydrogen consumption will grow slowly after 2037 however, as most natural gas used in industry is as a reagent rather than a fuel source. Beyond 2040, natural gas as a primary fuel source may further decline as hydrogen becomes increasingly prevalent in domestic and global energy supply chains.

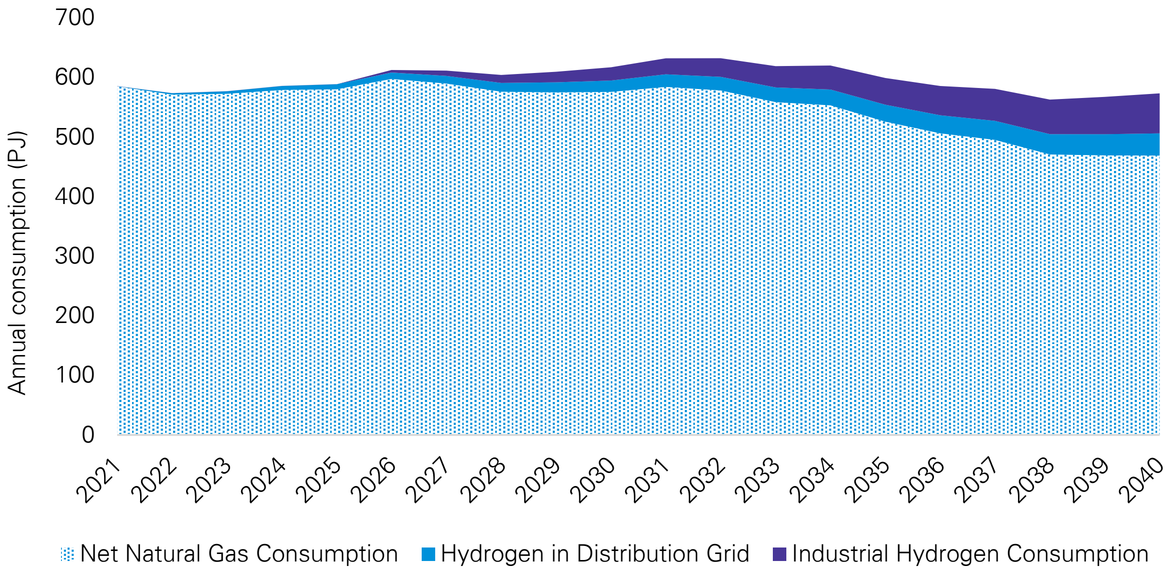


Figure 35 – Forecast hydrogen demand relative to natural gas
(Source: AEMO & KPMG analysis)

5.3 Gas supply

The production of gas in the ECGM is adequate to service current and forecast domestic gas demand, assuming that gas produced above contracted LNG volumes is directed into the domestic market. The challenge in supplying sufficient gas to domestic consumers is not production volumes, but the ability to transport those volumes from the producers, which are increasingly located in the north (Queensland and Northern Territory), to consumers, who are located in the south (Victoria, New South Wales and South Australia).

Traditionally, gas production to meet demand from the southern states has primarily come from the Victorian gas basins – Gippsland, Otway and Bass – with production from these fields typically well in excess of Victorian demand. However, southern supply from existing and committed gas developments is forecast to reduce by more than 35% (163PJ) over the next five years, due to declining legacy fields.

In contrast, AEMO expects new and existing gas fields in Queensland and the Northern Territory to increase supply from approximately 77% of total ECGM supply in 2020 to 81% in 2024, helping to meet expected demand in eastern and south-eastern Australia (including tenements in Queensland that are reserved for domestic market use only). This is driving a change in where gas is produced and how it is transported across the ECGM. Further supply may be added to the system if proposed developments of LNG regasification import terminals in south-eastern Australia proceed.

5.3.1 Current and forecast gas supply

AEMO considers current gas production and transportation capacity across the eastern states is sufficient to meet current gas demand. However, despite ongoing field developments and increases in

2P developed reserves, production from existing gas fields is in decline, particularly among southern fields. Gas production from existing and committed gas developments is forecast to provide adequate supply to meet gas demand until between 2023 and 2025 depending on the demand scenario, however this assumes that cargoes of export LNG above contracted levels are diverted to meet domestic demand if needed.

If anticipated gas field projects are developed, resource adequacy improves until at least 2026 (Figure 36). However, due to the location of most of the anticipated projects within Victoria, dynamic operational pipeline constraints would limit their effectiveness in addressing the forecast peak winter day supply gaps under certain conditions.

Beyond 2026, existing, committed and anticipated projects are forecast to be insufficient to meet southern demand, and southbound pipeline infrastructure upgrades would be required to deliver more gas from northern to southern states, particularly during winter peak days (refer Section 5.4 for details). Alternatively, planned LNG import terminals will need to supply gas into southern markets during peak seasons to address shortfalls from northern piped gas (refer Section 5.5.2).

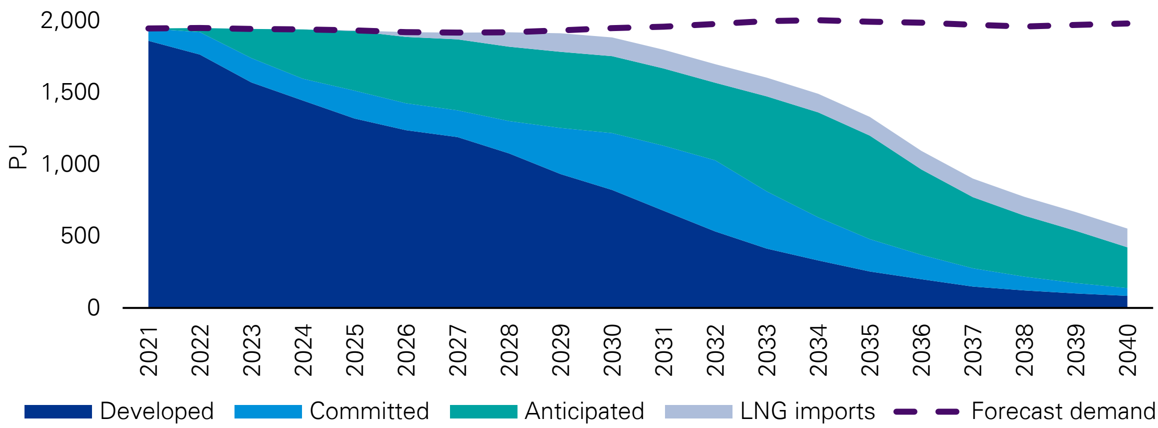


Figure 36 – Forecast ECGM gas production (including LNG import)
(Source: AEMO & KPMG analysis)

5.3.2 Diversion of LNG export volumes to service domestic demand

Australian Domestic Gas Security Mechanism (ADGSM)

In response to price increases during 2016 and 2017, the ADGSM was established as a temporary supply security measure to cease on 1 January 2023. The ADGSM is intended to ensure sufficient supply of natural gas to meet the forecast needs of energy users in Australia. It aims to do so by limiting exports of LNG during a "domestic shortfall year" and establishing a licensing regime whereby the Resources Minister may grant export permission to LNG exporters.

Under the ADGSM, LNG export restrictions will be imposed in only a "domestic shortfall year." In order to arrive at such a conclusion, the Resources Minister is required to formally issue a declaration to announce his/her intention to consider whether the forthcoming year will be a domestic shortfall year (the "Declaration"), consult relevant market bodies, Government agencies, potentially impacted industry players, other relevant Australian Government ministers and other stakeholders to seek their view on the then-current and forecast gas market conditions and any potential for a gas market shortfall (the "Consultation") and, if he/she has reasonable grounds to believe that there is a domestic gas market shortfall after the consultation, make a determination that gas export controls will apply in a particular year (the "Determination"). Since the introduction of the ADGSM in 2017, the Resources Minister has not declared a domestic shortfall year.

A 2019 review of the ADGSM concluded that the improvement in the domestic supply outlook and subsequent market conditions (since 2017) can, in part, be attributed to the ADGSM. In particular, LNG exporters have increased their supply to the domestic market since the ADGSM was introduced and are currently, in aggregate, net contributors to the domestic market. The review recommended retaining the ADGSM until the scheduled 2023 cessation and amending the guidelines to include reference to the ACCC's LNG netback price series in estimating a potential shortfall. This stops short of introducing direct price controls in the ECGM, but it does link the ADGSM to LNG netback prices.

Heads of Agreement

On three occasions, a HoA has been signed by the Australian Prime Minister and representatives of the three east coast LNG exporters (APLNG, GLNG, QGC) to ensure these producers make available a secure supply of gas to the east coast market. Under the agreement, LNG exporters committed to offer uncontracted gas to the domestic market before selling this gas internationally.

Domestic Gas Reservation Scheme

Whilst the ADGSM functions somewhat as a domestic gas reservation scheme, the Australian Federal Government has announced its intention to explore options for a national domestic gas reservation scheme. This may take the form of an acreage reservation, preferential reservation, blanket reservations or case-by-case assessments. As the states hold jurisdiction over onshore petroleum resources, any Federal Government scheme would need to be implemented with support of the states.

Queensland – Through its regulation of petroleum leases, the Queensland Government imposes a condition on certain tenements that any petroleum developed on the leased acreage must be sold and used only in Australia. Recently, the Queensland Government included a specific requirement for gas produced to be supplied to domestic manufacturing consumers. This approach will not impact the market materially because it will simply displace existing supply to these consumers. An independent review of this policy in 2019 found that stakeholders broadly accepted the policy but noted there was room for improvement around adaptability, efficiency and transparency, and provision of information to market participants.

Western Australia – Western Australia adopts a policy that requires LNG producers to reserve the equivalent of 15% of LNG production for the domestic market. LNG producers can obtain project approval by proving they will reserve gas for the market, develop the necessary infrastructure, and show diligence and good faith in marketing the gas. The policy has been in place for several years and is flexible with respect to exact timing, price, and sale conditions. The Western Australian domestic gas reservation policy has been relatively successful in terms of supporting the domestic market and not being a significant impost on LNG producers. One of the reasons for this is that in Western Australia the natural gas industry is predominately offshore, with conventional wells extracting large reserves of gas and without the complications of CSG production.

5.3.3 Forecast supply and shortfall (daily)

When assessing supply adequacy, it is important to take into consideration both annual and daily field production limitations. Whilst average annual supply may meet or exceed average annual demand, the demand for gas is typically seasonal – daily demand peaks exist in winter months as gas usage increases as a result of increased heating loads. In addition to seasonally driven demand, declining fields such as those in southern states also become maximum flow rate limited – meaning the maximum amount of gas able to be extracted from the field declines. Both of these factors combine to create daily supply-demand gaps that are not apparent when only considering annual average flows.

An example of this daily supply-demand gap is highlighted in modelling by AEMO, which has calculated supply-demand gaps between 13TJ and 374TJ/day across winter 2024 as declines in peak southern production, coupled with physical bottlenecks, generate supply shortfalls that are not evident in the annual supply-demand analysis (Figure 37).

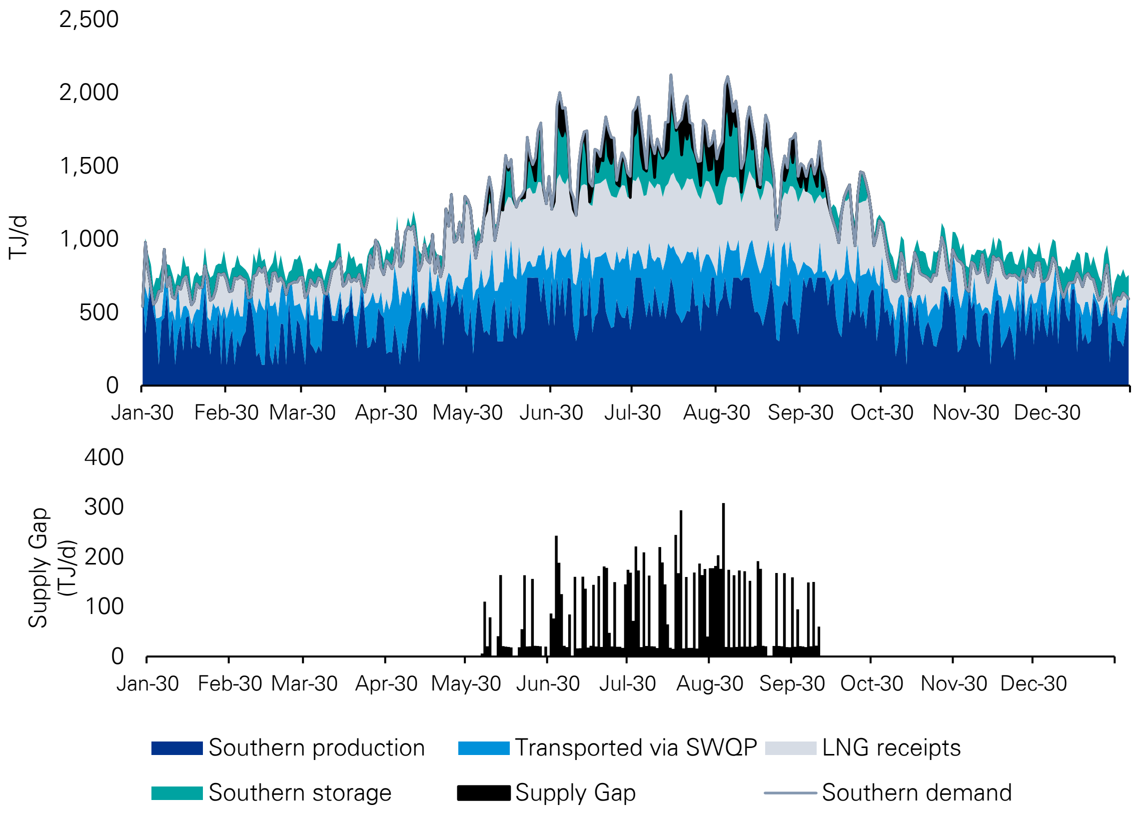


Figure 37 – Daily supply-demand gap in southern states – 2030

(Source: AEMO & KPMG analysis)

Fortunately for the supply-demand balance across the east coast, Queensland gas demand has much less seasonal variation, and so the northern fields' ability to meet peaks and troughs in daily demand is much less of a concern than in the southern states.

Additionally, LNG export demand typically peaks over the Australian summer months as global demand for LNG is highest during the Northern Hemisphere's winter season. In aggregate, Queensland seasonal demand peak is forecast to occur over summer, and southern demand peaks are forecast to continue to occur in winter.

As a result, on balance, northern supplies are still sufficient to meet daily and annual supply-demand gaps. On balance, gas production capacity, supported by new upstream developments in the north, is expected to be sufficient to meet both LNG and ECGM demand. However, limits related to transport and storage capacity, which are a key part of the supply chain, will need to be addressed through further investment.

5.4 Transport and Storage

Connecting producers to consumers in the ECGM is a network of bidirectional transmission pipelines connected to trading hubs and gas storage facilities between Queensland and Tasmania. As gas flows net-south (from Queensland into New South Wales and Victoria especially) increase, the transmission pipelines and storage facilities are increasingly becoming capacity constrained, leading to projected shortfalls in supply during peak winter periods.

5.4.1 Transmission pipelines

The pipelines leading south through, and downstream of, Wallumbilla have various usage patterns, with some pipelines having a strong correlation between usage and winter months in Australia. The SWQP is most prominent given that the pipeline provides access from northern to southern markets during winter months (Figure 38).

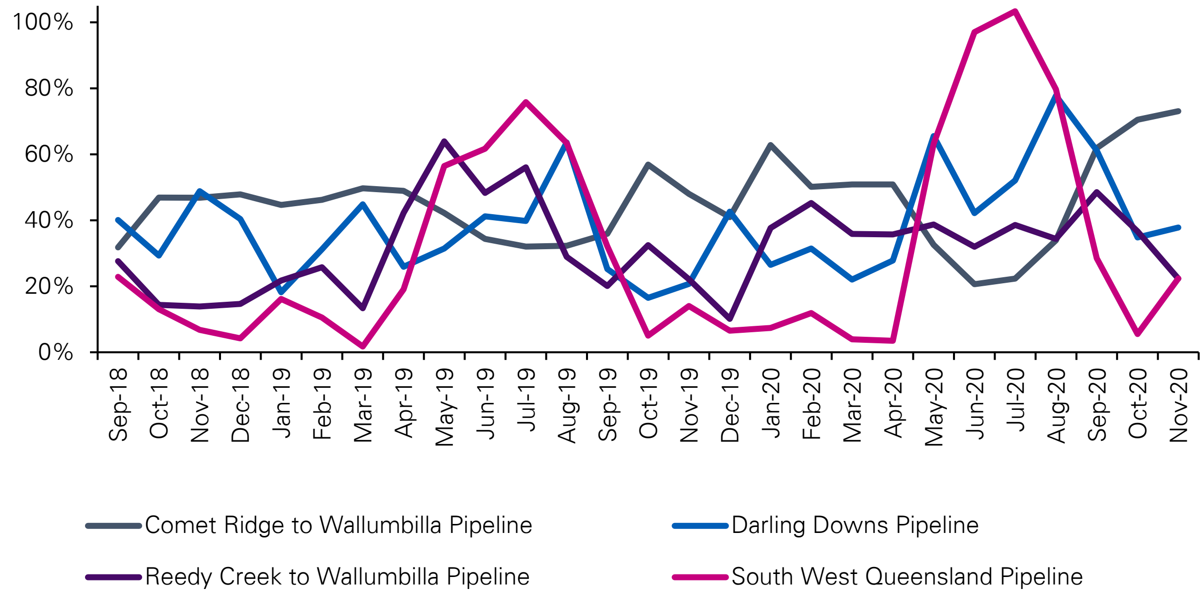


Figure 38 – Pipeline utilisation at Wallumbilla showing seasonality
(Source: AER Bulletin Board & KPMG analysis)

The SWQP is currently the only link between the northern and southern gas systems and is the limiting factor in transporting northern gas to southern states. It connects to the MSP and the Moomba to Adelaide Pipeline System (MAPS) (Figure 39).

Flow in the pipeline is bidirectional, and so it can be used to shift excess supply or meet peak demands in either system – meeting southern peak demand days in winter and sending excess southern gas north during summer or shoulder periods.

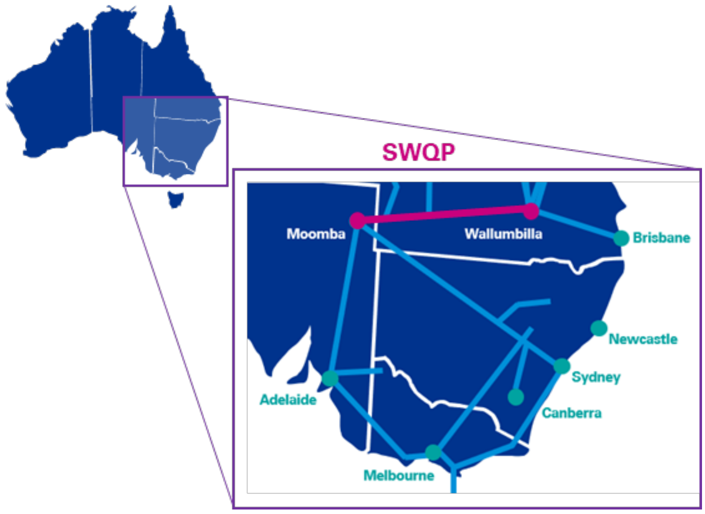


Figure 39 – South West Queensland pipeline location
(Source: KPMG analysis)

Recently, the SWQP has been increasingly used to help meet demand in the southern states – gas was transported towards the southern states on over 70% of days in 2019, compared to fewer than 10% of days in 2016. The quantity of gas transported south has also increased, with gas transported south exceeding 200TJ on approximately 25% of days in 2019, compared to fewer than 10% of days in 2018. In part, this is due to the addition of the NGP to the ECGM in January 2019, taking Mt Isa gas demand away from the SWQP.

Figure 40 shows the total SWQP capacity and the split between contract and uncontracted capacity. During non-winter months, the proportion of uncontracted capacity is approximately 25%. However, during winter months, the proportion of uncontracted capacity drops to 10%. Given that the SWQP is the critical link between northern gas producers and southern gas consumers, shippers that do not currently have firm capacity on this facility may find it challenging to bring any additional gas from Queensland to the southern states.

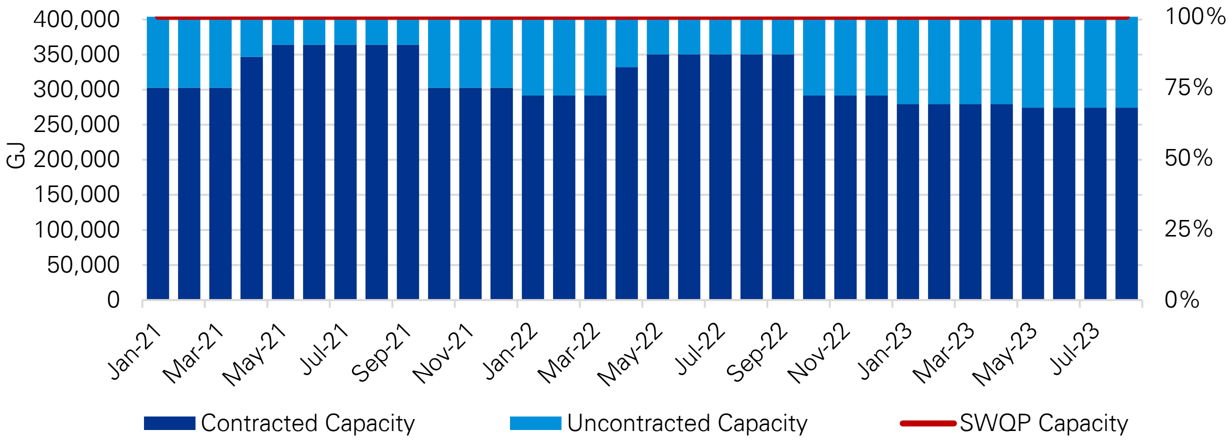


Figure 40 – SWQP capacity – 2021-2023

(Source: AER & KPMG analysis)

In the absence of greater southern supply sources being opened (either through the lifted ban on conventional gas exploration from mid-2021 or through LNG imports), meeting the gap in demand will require greater flow through SWQP from production sources in Queensland.

AEMO's analysis indicates that under their central scenario, by 2022 only 4% of days will have gas flowing towards Wallumbilla on SWQP. By 2023, all days will have net flow towards Moomba in order to meet southern demand (Figure 41). This will require a significant increase in supply sourced from Queensland through Wallumbilla in order to meet this flow rate.

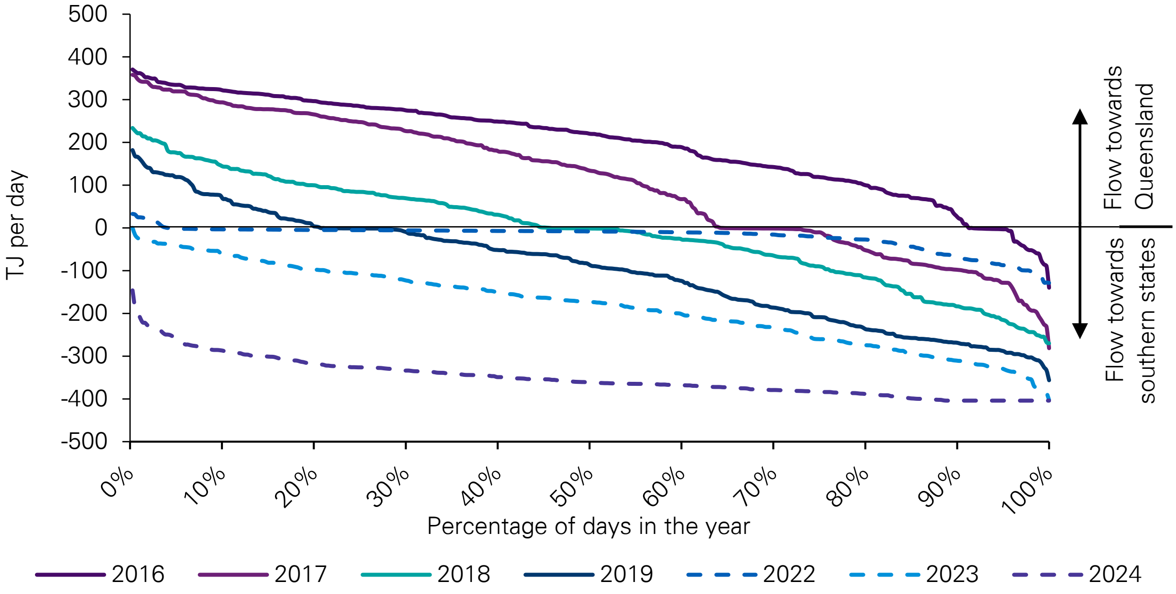


Figure 41 – Historical and forecast flow distribution curve for SWQP
(Source: AER & KPMG analysis)

The options to overcome these transport challenges include additional compression to increase the capacity of the SWQP, or potentially executing gas swaps with producers that have positions downstream of SWQP, including Santos and others with gas positions at Moomba.

There are several proposed transport projects that are aiming to alleviate constraints on the SWQP, including:

- Upgrading the SWQP to provide an additional 25% capacity in both directions (see below APA Group East Coast Grid Expansion project);
- Upgrading the MWP to provide an additional 25% toward Sydney;
- Upgrading the Victoria-New South Wales Interconnector to provide an additional 125TJ/day toward Victoria; and
- Upgrading the Eastern Gas Pipeline so that it can flow bi-directionally.

There are also proposed projects that aim to construct new greenfield pipelines from the Amadeus Basin and to connect Wallumbilla to Newcastle, however these are unlikely to proceed during the forecast period when compared to other upgrade projects.

APA Group East Coast Grid Expansion

As owner and operator of the SWQP and MSP, APA Group is currently undertaking an expansion project to improve capacity to transport gas south on both pipelines. The additional capacity is expected to deliver sufficient gas to meet forecast winter shortages from 2023.

The expansion will be delivered at a capital investment of approximately $270 million. It will increase winter peak capacity of the East Coast Grid by 25% through additional compression and associated works on both the SWQP and the MWP.

The first stage of expansion works will increase Wallumbilla to Wilton capacity by 12% and is targeted for commissioning in the first quarter of calendar year 2023, ahead of forecast southern state winter supply risks identified in the 2021 AEMO Gas Statement of Opportunities.

The expansion will be delivered in a number of stages:

- Stage 1: The first stage of expansion works includes the construction of a single site of compression on each of the SWQP and MWP and will increase gas transportation capacity by 12%.
- Stage 2: The second stage of expansion works includes an additional site on the SWQP and MWP which will add a further 13% of capacity.
- Stage 3: APA is undertaking engineering and design works on a potential third stage (three additional compressor locations on the MWP) of the East Coast Grid to add a further 25% transportation capacity.

Most of the expansion works will occur on APA owned sites, which have existing infrastructure. Each project site will require a peak construction workforce of around 80 people. Construction of the proposed East Coast Grid Expansion Project is planned to commence in the first half of 2022. The construction of each compressor station is intended to take approximately nine months.

5.4.2 The role of gas storage facilities

For seasonal peaking, as assurance against potential supply disruption, and in order to take advantage of seasonal pricing variation, a number of gas storage facilities exist in the ECGM. There are four major southern facilities devoted to storage which are:

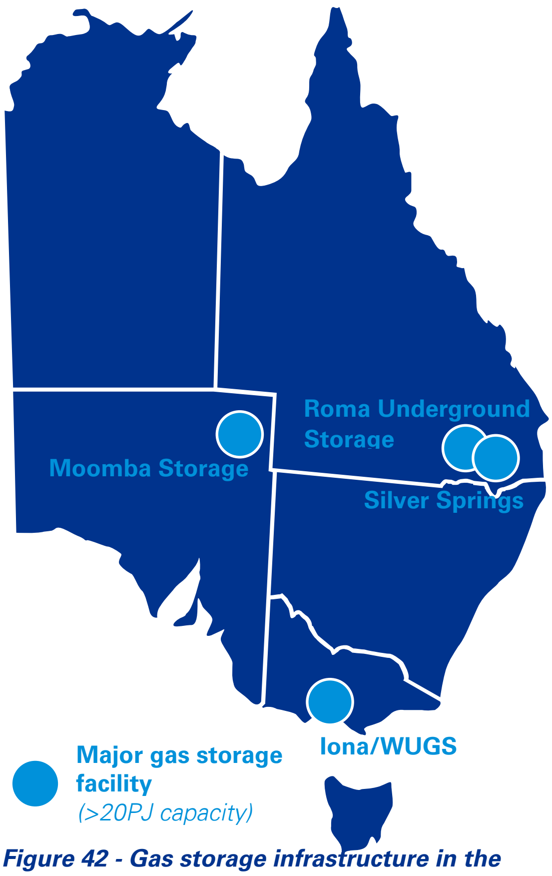


Figure 42 - Gas storage infrastructure in the ECGM

(Source: KPMG analysis)

- Roma Underground Storage (RUGS) (Surat Basin) – >50PJ;
- Silver Springs (Surat Basin) – 35PJ;
- Moomba storage (Cooper Basin) – 85PJ; and
- Iona/WUGS (Victoria) – 22PJ.

Storage facilities provide additional flexibility to help meet maximum demand requirements by storing surplus gas supplies produced in summer for use in winter. The ability for storages to be refilled to capacity and/or to deliver gas at maximum withdrawal rates may, at times, be limited by pipeline capacity.

Over recent years, as maximum daily production capacity in southern states has reduced, there has been an increased reliance on storages. As shown in Figure 43, from 2017 through to 2019, each year successively drew on more storage to help supply peak and seasonal demands. In 2020, this observed trend was disrupted due to reduced total consumption, particularly from GPG consumption, despite a small increase in southern residential and commercial consumption, impacted by colder winter conditions.

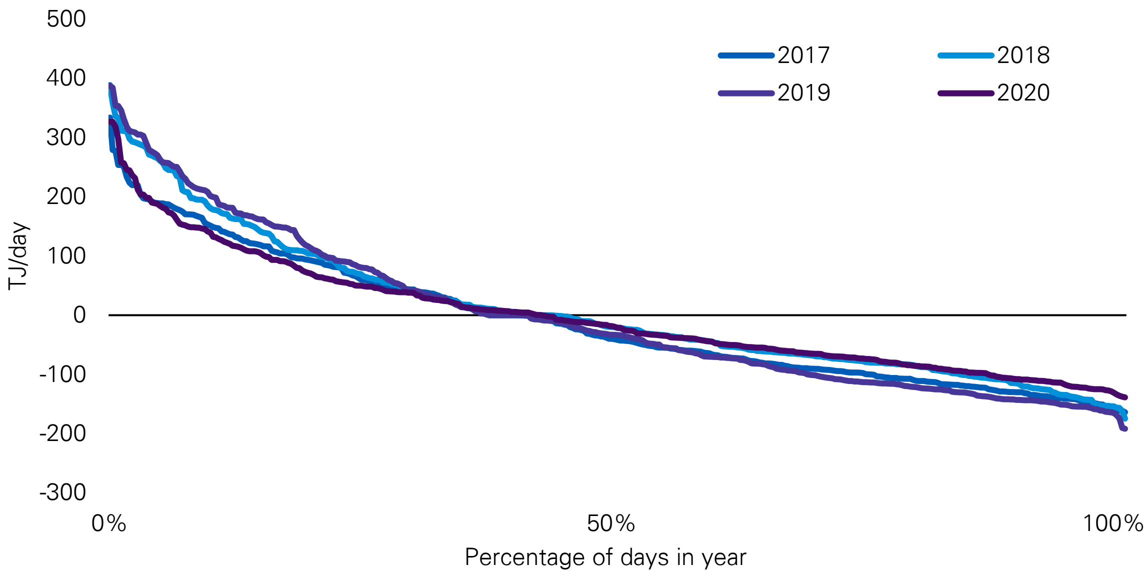


Figure 43 - Cumulative distribution of net changes in storage level for Iona UGS, 2017 to 2020
(Source: AER & KPMG analysis)

The critical role for gas storage is expected to increase as the maximum daily production capacity decreases further, particularly after 2023, although this may depend on the cost-competitiveness of LNG import relative to storage. Storage tariffs are generally not publicly released by the proponents, but estimates indicate that storing gas can add $0.50 per GJ per day to the cost of delivered gas.

Existing storages alone cannot provide sufficient flexibility in the system long term to manage the seasonality of southern demand as the storage capacities are simply not deep enough. Proposed projects to expand capacity will improve their effectiveness but are still not expected to be the sole solution to the seasonal supply-demand gaps.

Proposed Storage Projects

There are three major projects proposed to increase ECGM storage capacity beyond its current 110PJ:

- **Golden Beach Gas Storage Facility** (Gippsland Basin, Vic) – GB Energy's Golden Beach project is designed for 12.5 PJ capacity with an estimated completion date in 2024.
- **Iona Storage Expansion** (Victoria) – Lochard Energy's Iona storage expansion is in the early planning stage with an 18-month development timeframe from FID. The capacity of this project is to be confirmed.
- **SWP (South West Pipeline)** (Geelong-Port Campbell, Vic) – APA's SWP project (designated WORM) is an augmentation of the transmission system which will enhance the Iona system's storage filling capacity as well as potential increases in storage capacity elsewhere in the system.

5.5 Alternative sources of supply

Increasing supplies of gas from northern states into southern states via increased transport capacity and more efficient use of existing capacity is a key part of meeting southern demand. In addition, several projects have been announced that propose to supply alternative sources of gas into southern networks, including LNG import terminals, developing other frontier basins (such as the Beetaloo Basin) and developing other upstream gas projects (such as Narrabri).

5.5.1 Other frontier basins

Beetaloo Basin

The Beetaloo Basin is located in the central portion of the Northern Territory between McArthur River and Tennant Creek. The region contains moderate amounts of shale gas which can be accessed through hydraulic fracturing.

The Beetaloo sub-basin has been extensively studied for potential development of onshore gas production and has been estimated to have 2C contingent resources of 6,996PJ of natural gas as of 2019. The Beetaloo Basin has been extensively reviewed for the potential to develop its resource in a series of studies which identified potential development scenarios for hydraulic fracturing and the infrastructure requirements to bring the gas to market.

Development of the Beetaloo Basin has been anticipated based on a 100 well per year drill program with each well anticipated to be comprised of a 2,000m horizontal well with 40 fracturing stages. Gas would be supplied to existing pipeline infrastructure to the NGP or Amadeus networks as well as produced liquids being trucked to Darwin for further processing and separation.

The commercial potential of the Beetaloo Basin has been modelled to indicate a break-even gas price of $9/GJ for shale gas supplied to the market for mid estimate supply of 9.2 Tcf of commercially viable gas. If gas prices rise to AUD$12 / GJ then potentially far more gas becomes commercially viable (63.3 Tcf). The development of the Beetaloo Basin is largely considered to be conducive to new LNG export infrastructure in the Northern Territory or backfill for the existing Darwin LNG liquefaction plant. Development of the Beetaloo Basin will require significant investment, as it is a truly frontier basin with limited existing infrastructure, exploration or appraisal activity.

Estimates of time to first gas from a Beetaloo Basin development are beyond the 10-year mark, and it is expected that development of the Bowen Basin could be achieved much more quickly than the Beetaloo.

Galilee Basin

The Galilee Basin is a region in central Queensland situated between the Bowen and Cooper Basins. It is currently home to a number of coal mines and is prospective for unconventional gas, both in underground reservoirs and in the form of coal mine methane. The exploration of the region is in its early stages; however volumes of gas are anticipated to exist in the region due to its geological setting and similarities to its neighbouring basins in the Bowen and Cooper regions.

The Galilee Basin has several granted coal mining leases to Adani Mining Pty Ltd for their Carmichael project as well as numerous applications by a number of other proponents of the Basin totalling 1.5% of the Basin's geographical area. The Carmichael Mine was initially proposed as the largest coal mine in Australia; however it has been scaled back to a 10Mtpa project which is anticipated to begin production by the end of 2021.

The Galilee Basin is prospective for gas; however it is anticipated to be relatively high cost due to sparse deposits – although more exploration is required. The infrastructure in the Basin is very limited, and it is not effectively linked to the ECGM by pipeline. Rail and transport infrastructure is also extremely limited, although a rail corridor has been planned and is supported by existing policy measures (the Galilee SDA) to support the provision of Galilee coal to the Abbot Point Coal Terminal in North Queensland. Substantial investment is needed in infrastructure, exploration, and development before the Galilee can be considered as a viable supply competitor to the Bowen.

Narrabri gas project

The Narrabri gas project is a Santos project which has recently gained appropriate approvals for the development of natural gas reserves in Narrabri in northern NSW. This project is anticipated to supply NSW domestic demand via existing pipeline infrastructure on the Moomba to Sydney line through the construction of a linking pipeline constructed by the APA Group. The project has attained approval from the federal environmental minister with work on the project having commenced in 2021. This comes after 10 years of political debate due to the controversial fracking methods which will be used to access gas from local basin water. The gas produced will be through hydraulic fracturing of deep (500-1200m) coal seams.

If approved, the Narrabri project is considered to have the potential to produce 200 TJ/d of gas from up to 850 individual wells. However, with projected supply deficits on the horizon, the market is anticipated to be adequate to service both supplies concurrently. The project is anticipated to cost approximately AUD$3.6Bn and will have a project life of 20-25 years. It will directly compete with potential supplies of gas from the Bowen basin for the southern ECGM market. If approved, the project will supply half the demand for gas in NSW.

Although the project has been approved by both state and federal planning authorities, legal proceedings are underway as the decision is being appealed in the Land and Environment Court. The appeal is being brought to bear by local landholders and environmentalists on the grounds that regulators were 'legally irresponsible' for approving the project. The appeal claims that the Independent Planning Commission (IPC) did not adequately consider the effect of greenhouse gas emissions, however Santos's legal defence has argued that the IPC was reasonable in its decision. While this appeal is still in the court system, the project is paused awaiting a result and hence production is delayed indefinitely.

5.5.2 LNG import

A number of LNG import terminals are proposed along the east and south-eastern coastline of Australia. The purpose of these proposed LNG import terminals is to provide alternate sources of gas supply to attempt to fill projected supply-demand gaps in the ECGM. Whilst the import terminals may be part of the solution that addresses domestic gas shortfalls, it remains to be seen if seasonal peaking use is economic when compared with further investment in onshore piped gas.

LNG import process

The LNG import terminals proposed in Australia will utilise Floating Storage & Regasification Units (FSRUs), which are marine vessels used to warm LNG to return it to a gaseous state. Seawater is used for this warming, where the LNG and seawater are flowed through a tube and shell heat exchanger. The difference in temperature between the inlet seawater and outlet seawater is initially about -7ºC, this then blends back to ambient temperature when the cooler seawater is discharged to the environment. Working at full capacity, it takes approximately six days to re-gasify a 170,000m^3 cargo of LNG.

The limiting factor for operation of an FSRU in Australia is the volume, temperature and chlorine content of the discharged warming water. The Port Kembla Gas Terminal, for example, has environmental conditions that will limit the discharge of warming water that effectively constrains its capacity to import LNG to 130PJ per year.

The role of LNG imports

The advantages of importing LNG rather than transporting gas from northern producers include the ability to purchase LNG during the Northern Hemisphere's summer when prices are lower and sell gas into the Australian winter market (when domestic prices are higher). This presents a competitive option to piped supplies that require storage in the southern storage facilities for use during peak periods of demand.

LNG import terminals play a role in supplying peak shaving gas into the ECGM during winter demand periods (see Figure 44). Given the forecasts provided by AEMO in the 2021 Gas Statement of Opportunities (GSOO), there is likely to be sufficient demand for LNG import to support two terminals, potentially one in NSW (Port Kembla) and one in Victoria.

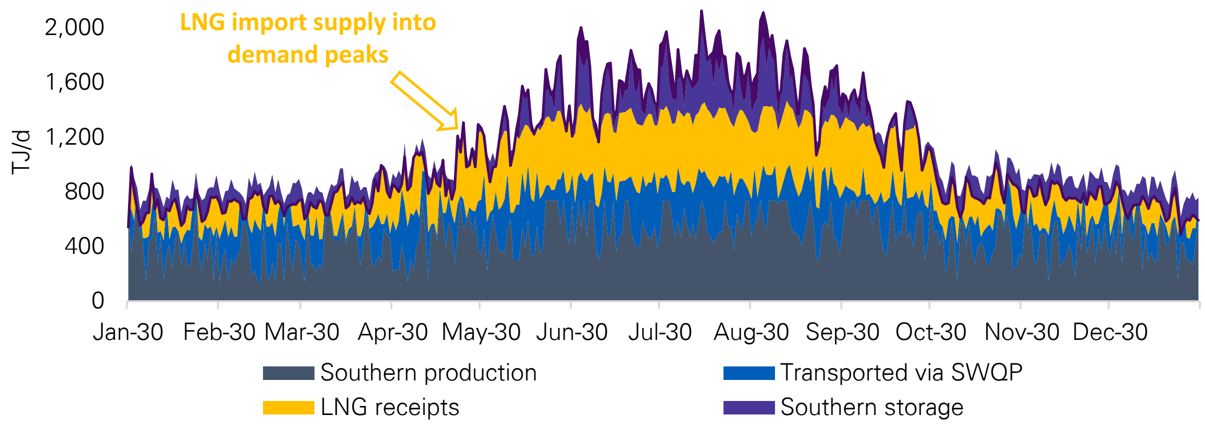


Figure 44 – The role of LNG in addressing the supply-demand gap, 2030
(Source: AEMO & KPMG analysis)

Proposed projects

Several projects propose to supply gas via FSRUs at dedicated LNG import terminals. These projects include terminals at Port Kembla and Newcastle in New South Wales, Corio Bay and Port Philip Bay in Victoria and Port Adelaide in South Australia:

Table 5 – Proposed LNG import terminal projects in the ECGM
(Source: KPMG analysis)

	Port Kembla	Port Adelaide	Newcastle	Corio Bay	Port Philip Bay	Crib Point
Proponent	AIE	IG Partners	EPIK	Viva Energy	Vopak	AGL
Capacity	275TJ/d	330TJ/d	TBC	275TJ/d	TBC	550TJ/d
Location	NSW	SA	NSW	VIC	VIC	VIC
Project status	Operational by end 2022	Operational by Oct 2022	Approvals pending	Approvals by 2022	Announced	Cancelled

5.6 The need for a new gas basin

The ECGM is a complex, interconnected network of physical infrastructure, commercial positions and regulatory frameworks. Overall, forecasts consistently predict a shortfall of gas supplies into the market by the mid-2020s, starting with peak demand periods (winter) and extending to net annual shortfalls. This will drive upwards pressure on domestic gas prices and downward pressure on consumption, and thus economic activity in gas-intensive industries.

Various projects and initiatives are slated to address these forecast shortfalls; however no single project is a solution to the challenges identified in this report. There remains the strong possibility that there will be residual gas demand of several hundred terajoules per day that could ultimately be filled by development of the Bowen Basin. It is important to note that the Narrabri Gas Project is already included in AEMO's supply-side modelling of ECGM gas supply, and still a supply-demand gap exists, as outlined in the above analysis.

> There is clear potential for the Bowen Basin to be developed as a new upstream source of gas that, if connected to the ECGM, would help contribute to closing the projected gas supply-demand gap.

As such, there is clear potential for the Bowen Basin to be developed as a new upstream source of gas that, if connected to the ECGM, would help contribute to a closing of the projected supply-demand gap. Physical connection to the ECGM is not necessarily required, as directing Bowen Basin gas to export via the facilities at Gladstone would enable swap positions to be executed with gas shippers that are connected to the ECGM as the Bowen gas displaces ECGM gas that would otherwise have been exported.

Whilst other prospective basins exist and could also be developed to provide gas into the ECGM, the Bowen Basin is considered to be in prime position to supply this shortfall due to the level of existing infrastructure, existing production and extensive exploration and appraisal activity. Based on analysis undertaken for this report, it is anticipated that the likely timeline for development of the Australia's prospective basins may be:

1. Bowen Basin: 5+ years;
2. Beetaloo Basin: 10+ years; and
3. Galilee Basin: 15+ years.

6. The Bowen Basin

6.1 Location

As illustrated in Figure 45, the Bowen Basin extends southwards from Collinsville (near Bowen) to Emerald and Moura (west of Bundaberg). Its area is put at 60,000 to 75,000 sq km, over a length of approximately 650 km. The Basin is shaped like an inverted Y: the single stem of the Y runs from Collinsville to Dysart, a land corridor seldom wider than 50 km, where the majority of mines are worked. The two subsidiary stems run south-west to Emerald and beyond, and south to Moura and Theodore.

As detailed in Section 2, the scope of this study is centred on the Bowen Basin, which forms an approximate triangle from Collinsville in the north down to Theodore and inland towards Tambo in central Queensland (Figure 10). The Bowen Basin, alongside the Surat, is Queensland's largest gas and coal producing region and supplies a large portion of the LNG export and domestic gas along the East Coast.

The region contained within the Bowen Basin intersects large swathes of prime agricultural land near Mackay. This region is predominantly used for cattle farming and other agricultural activities, such as the cultivation of sugar cane and other fruit, vegetable, and grain crops. This region is also home to several large coal mining operations which produce metallurgical and thermal coal, generally with extremely high grades.

Much of the local economy is reliant on mining activities in the coal, gold, and other metals industries as well as the pastureland for prime cattle. Ultimately, this region is relatively sparsely populated with several dispersed population centres and large mining operations making up the majority of activity.

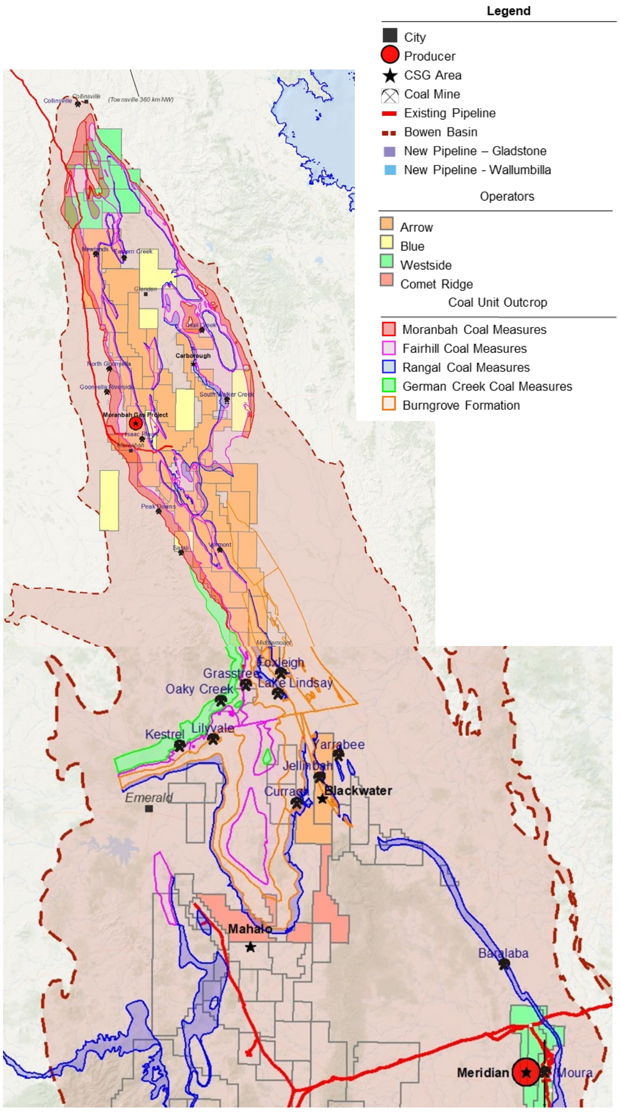


Figure 45 – The Bowen Basin

(Source: NSAI Analysis)

6.2 Geology

The Basin is home to several types of coal seams which have varying potential for gas. The Bowen Basin contains three main Permian coal measures – the Rangal Coal Measures (RCM), the Fort Cooper Coal Measures (FCM) and the Moranbah Coal Measures (MCM). The RCM are the shallowest seams in the Basin and have been extensively mined for coal along the eastern and western flanks where the coal is shallowest and typically, coal miners target coals that are less than 400m depth.

The Basin primarily contains sediments of Permian age deposited in fluvial, lacustrine, and deltaic settings. Minor marine influxes were also recorded. Most of the Basin's oil and gas discoveries to date are found along its southwestern margin, with the first commercial discoveries, the Timbury Hills and Pickanjinnie gas fields, occurring in 1960. The MGP is located along the western flank of the Northern Bowen Basin.

Permian-aged coal seams account for almost 80% of the coal in the State of Queensland. With four major coal measures of economic importance for coal mining, the Bowen Basin contains the state's most significant Permian coals. These measures, from youngest to oldest, are:

1. The Rangal/Bandana/Baralaba Coal Measures of Late Permian age;
2. The Late Permian Moranbah/German Creek Coal Measures;
3. The Collinsville/Blair Athol Coal Measures of Early Permian age; and
4. The Early Permian-age Reids Dome beds, present only in the southwestern corner of the Basin.

The North Moranbah underground coal mine, immediately to the west of PL 191, actively mines coal from the GM seam of the MCM. The MCM sub-crop immediately west of the mine area has unconformity under the shallow Cenozoic age cover, making them easily accessible to miners. The MCM consist of sandstones, siltstones, shales, and coals with numerous seams and splits. RCM coals are actively mined in the Basin approximately 25 kilometres north of the Moranbah CSG project area at the Burton Mine.

CSG produced at Moranbah is sourced from the Goonyella Middle (GM) and P seams of the Moranbah Coal Measures. Future production is likely from the Goonyella Middle Lower (GML) seam while the overlying Fort Cooper and Rangal Coal Measures have potential. Coal permeability in the Moranbah area is relatively low with production enhanced by in-seam drilling. Development has concentrated on seams around the 300m level to avoid the loss of permeability that generally comes with increasing depth.

The early data for this area are from numerous wells drilled by several coal companies to establish the location of coal seams and the viability of mining these coals. Initially, log data from these early wells were generally not available, but detailed schematics of the lithologies and formations encountered with depth were provided. The correlations in these schematics were then verified with well logs.

CSG prospective development has only been evaluated in this study for the RCM and the MCM. To date, economic CSG production has been established from the MCM and the RCM. However, promising gas content measurements have also been found in additional seams which may provide attractive drilling targets for future additional methane resources.

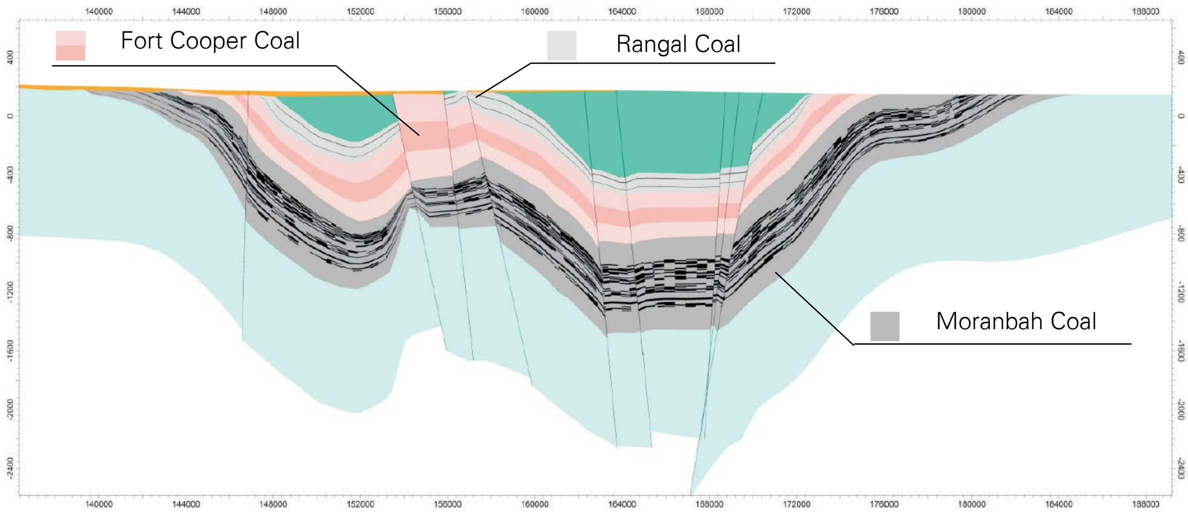


Figure 46 – Indicative cross section of Bowen Basin coal seams

(Source: Arrow Energy EIS, 2012)

6.3 Key Stakeholders

The Bowen Basin has over 40 active coal mines, two gold mines, producing gas fields and a range of gas and coal exploration and appraisal activities. As a result of this activity, the Bowen Basin contains a diverse range of key stakeholders from resource companies, government organisations, utilities providers and gas-intensive manufacturing and power generation assets. Figure 47 is a summary of the major stakeholders with interests in the Basin:

Figure 47 – Key stakeholders in the Bowen Basin

(Source: KPMG analysis)

6.3.1 Coal Seam Gas proponents

There are three major CSG proponents with active positions in the Bowen Basin; Arrow Energy, Blue Energy, and a joint venture between WestSide and Mitsui E&P, which have interests both in coal and in gas.

Arrow Energy

Arrow Energy Holdings Pty Ltd is a 50/50 joint venture between PetroChina and Shell which has been operating in the Bowen Basin since 2004. Arrow has a significant landholding in the Bowen Basin via its wholly owned subsidiaries BNG (Surat) Pty Ltd, Bow CSG Pty Ltd, and CH4 Pty Ltd, which hold Authorities to Prospect (ATPs) and Petroleum Leases (PLs) in the region. Arrow Energy has the most expansive land interests in the region. They are currently the only operating gas producer in the Study area, courtesy of their Moranbah Gas Project supplying gas north to Townsville. Arrow Energy's activities in the Bowen Basin include:

The Moranbah Gas Project a 50/50 joint venture with AGL Energy, which has a greater presence in the south of the Bowen Basin and in the Surat Basin. This project has been operating since 2004 and remains stable, supplying Townsville Power Station and industrial customers in north Queensland.

The Bowen Gas Project (BGP), where Arrow Energy proposes to develop CSG resources in an area of approximately 800,000Ha. The BGP includes the proposed Arrow Bowen Pipeline connecting Moranbah to the Gladstone LNG projects which is subject to separate approval processes.

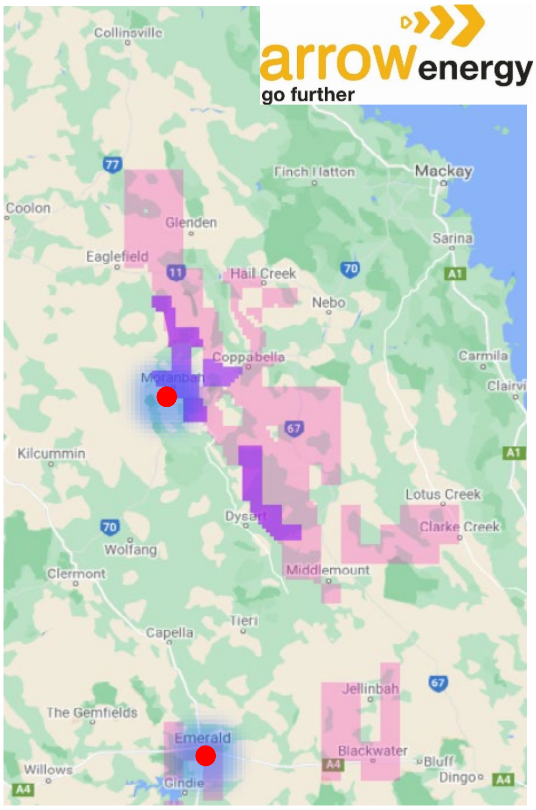


Figure 48 – Arrow Energy ATP and PL holdings

(Source: KPMG analysis)

Blue Energy

Blue Energy Ltd is an oil and gas exploration company with a significant land interest in the Bowen Basin being held by its wholly owned subsidiary Eureka Pty Ltd. Until mid-2018, Queensland Government-owned Stanwell Corporation Pty Ltd owned a 7.7% stake in Blue Energy.

Blue Energy's holding in the north of the Basin is ATP814. This ATP consists of seven disconnected blocks ranging from south of Moranbah up to Glenden. Blue Energy does not have any PLs in the area, because its activities are currently only exploratory.

Blue Energy's activities in the region include:

- Taking advantage of Arrow Energy's existing CSG production at its Moranbah Gas Project in the vicinity of ATP814 to advance its own commercialisation strategy. Drilling by Arrow and other adjacent operators to ATP814 has taken place, conferring currently uncontracted CSG reserves to Blue Energy.
- Blue Energy is the proponent of a gas pipeline from its ATP814 tenement in the Bowen Basin to Gladstone/Wallumbilla.
- 1,116 km^2 of exploration permits including CSG wells, ~71 PJ of 2P reserves and ~298 PJ of 3P reserves.

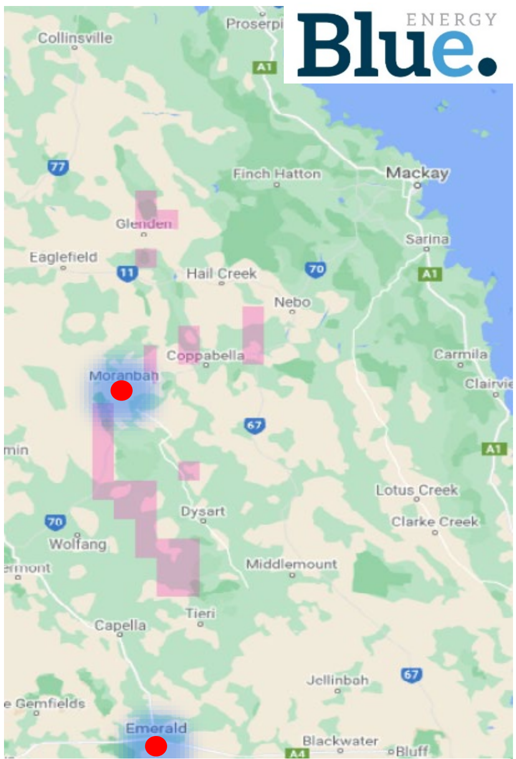


Figure 49 – Blue Energy ATP holdings

(Source: KPMG analysis)

WestSide / Mitsui E&P

Westside Pty Ltd is an oil and gas explorer and producer operating in Australia and New Zealand. It holds significant land interests in the Bowen Basin with its partner Mitsui E&P Australia Pty Ltd.

Westside's landholdings in the region are expansive. It operates the Greater Meridian Gas Fields, the closest gas fields to export facilities at Gladstone. It also has landholdings in the south of the Basin, where it is expanding its current activities in partnership with Australia Pacific LNG (APLNG). Westside and APLNG hold PL tenements south of Emerald.

Westside's current operations in the region include:

- Exploratory activities in its ATP688 tenement, north of Moranbah. Multiple exploratory wells have been drilled on the site and Westside intends to perform further testing to capture gas and water production data to evaluate the prospects of the field. This tenement is in the vicinity of the Moranbah to Townsville pipeline so presents a significant commercial opportunity.
- Currently producing 40 TJ/d, connected to GLNG pipeline and the QGP in the Meridian Project.

There are also a variety of smaller CSG proponents in the Basin, ranging from small holdings held by large multinationals, to exploration prospects owned by smaller companies.

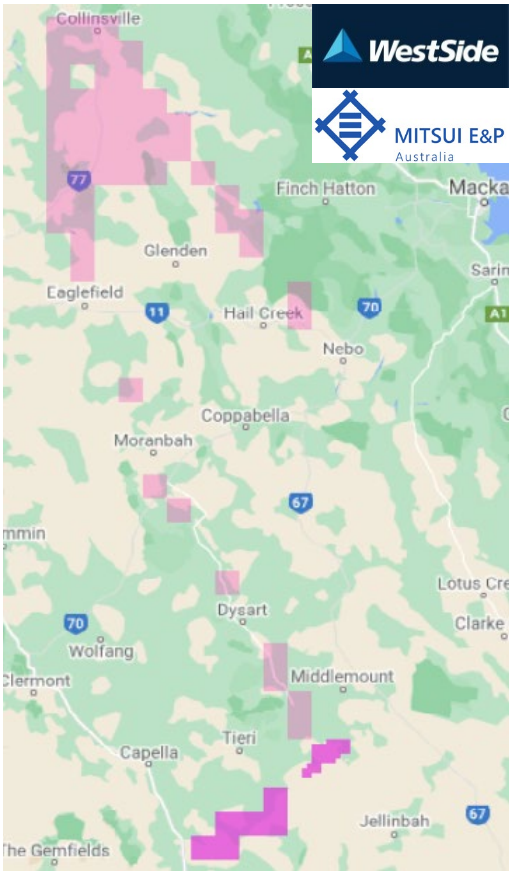


Figure 50 – WestSide/Mitsui ATP & PL holdings

(Source: KPMG analysis)

6.3.2 Coal mining proponents

The Bowen Basin is Queensland's largest coal mining region, producing large quantities of high grade metallurgical and thermal coal for export and domestic use. Coal mines exist across the Basin, from Collinsville in the north to the very south of the Basin near the New South Wales border (Figure 51). Notable coal miners with operations and acreage in the Basin include Glencore, Peabody, BMA/BMC and Anglo American.

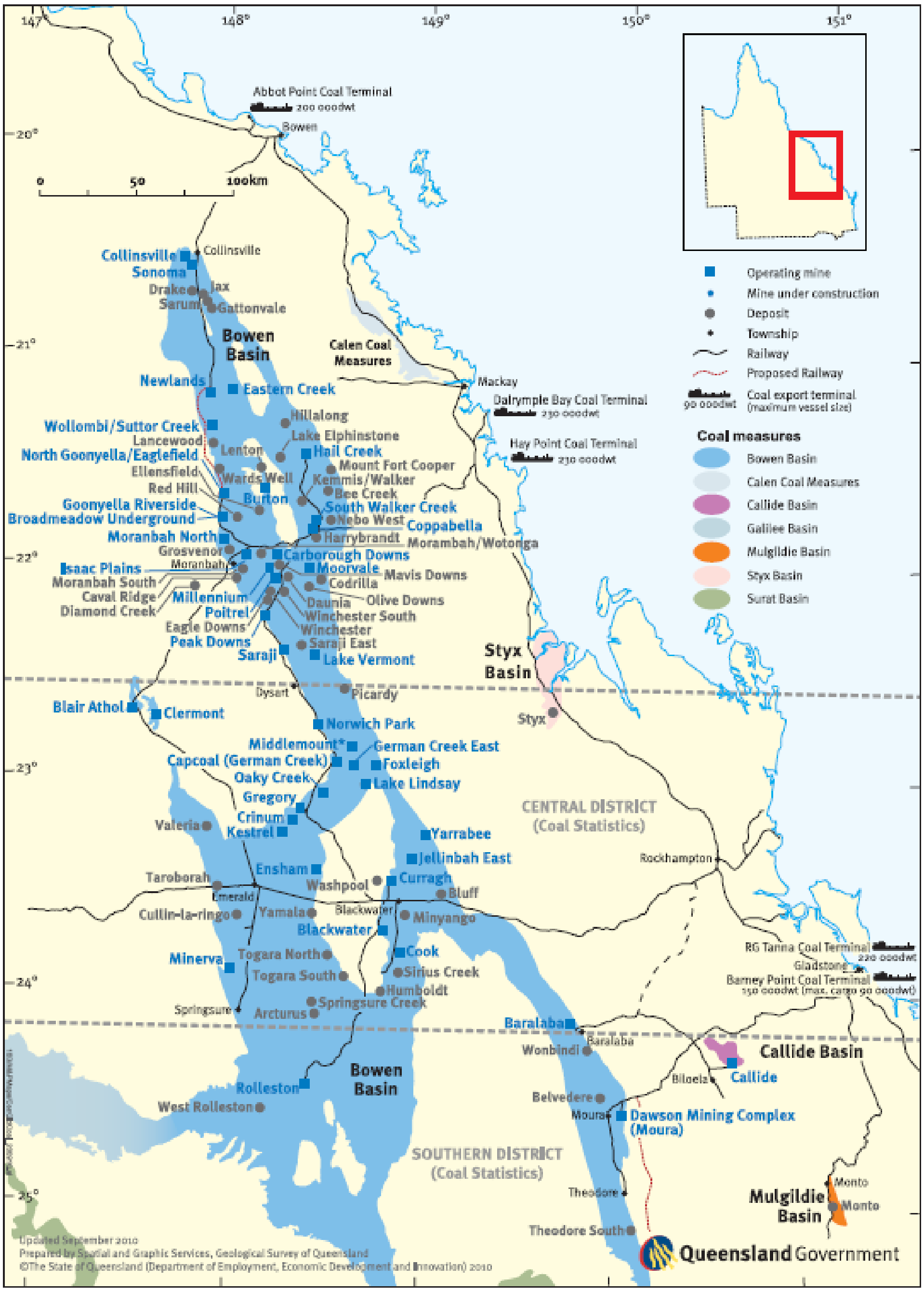


Figure 51 – Current coal mining operations in the Bowen Basin

(Source: QLD Government (2010). Central Queensland Coal. Department of Employment, Economic Development, and Innovation)

Glencore

Glencore PLC is a global commodity trader and mine operator with operations across the country from the Pilbara to Mt Isa and the Bowen Basin. Glencore is Australia's largest coal producer and has a large interest in the Bowen region with three major metallurgical coal operations in the northern portion of the Basin.

Glencore's operations in the Study area include:

- **The Newlands Complex** is an open pit and underground complex producing steaming and metallurgical coal with a production capacity of approximately 5.5Mtpa and a mine life of around five years.
- **Collinsville Mine** is also an open pit and underground complex mine producing both metallurgical and thermal coal. Production capacity of Collinsville is around 3Mtpa and has an expected mine life of 20 years.
- **Hail Creek** is a high-quality open pit Metallurgical coal operation with an annual production capacity of approximately 5.5 Mtpa and an anticipated mine life extending to 2040.

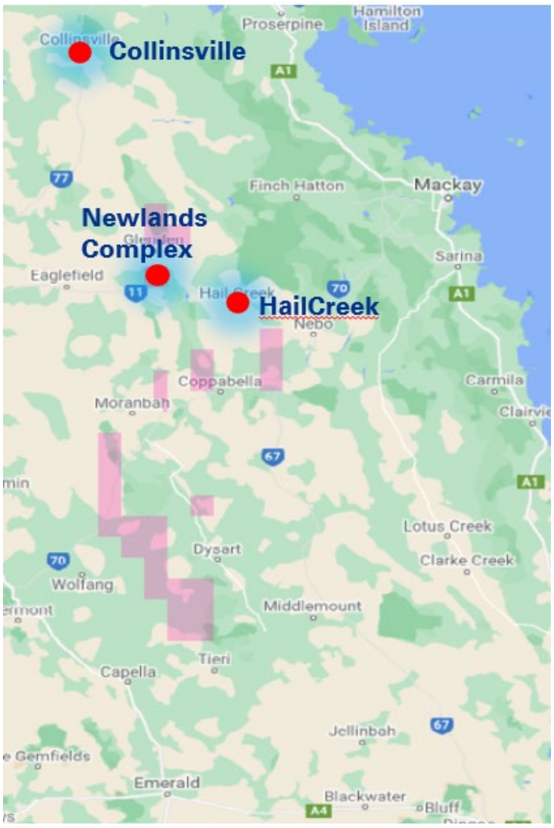


Figure 52 – Glencore operating assets

(Source: KPMG analysis)

BHP Mitsubishi Alliance /BHP Mitsui Coal

The BMA (BHP Mitsubishi Alliance) and the BMC (BHP Mitsui Coal) are subsidiaries of the BHP and Mitsubishi and Mitsui mining organisations. BMA is owned 50-50 by BHP and Mitsubishi and is the largest exporter of metallurgical coal in Australia. BMC is owned 80% by BHP and 20% by Mitsui. They operate multiple mines in the Bowen region as well as a substantial coal export terminal south of Mackay at Hay Point.

Their assets in the Study area include:

- **Blackwater** is an open pit mine producing both metallurgical and thermal coal with a mine life of 20 years as of 2020. Blackwater has a production capacity of approximately 13.5 Mtpa and is owned by the BMA joint venture (JV). Blackwater is one of the largest coal resources in the world with 860 million tonnes of proven reserves.
- **Goonyella Riverside Broadmeadow** is owned by the BMA JV and is an open pit and underground mining complex with a 40-year mine life and production capacity of 16 Mtpa of both thermal and coking coal.

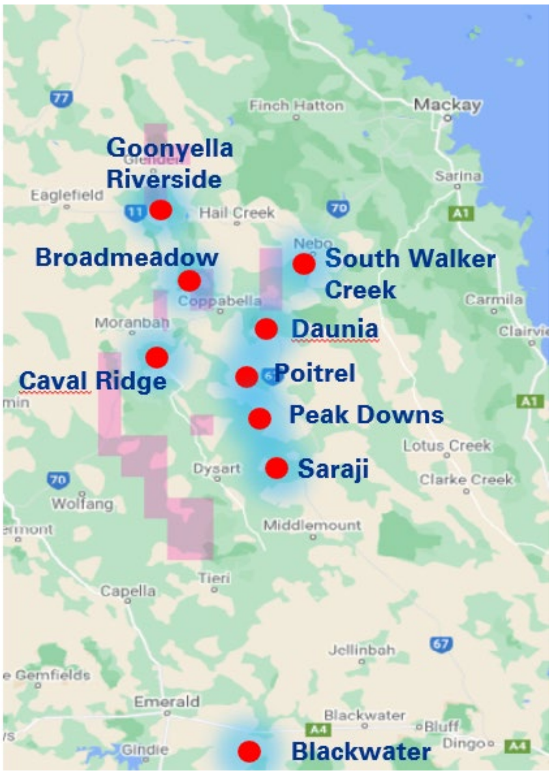


Figure 53 – BMA/BMC assets

(Source: KPMG analysis)

- **Caval Ridge** metallurgical complex (UG/OP) is owned by the BMA JV and has an annual production capacity of 5.5 Mtpa.
- **Daunia** open pit mine can produce 4.5Mtpa of metallurgical coal and is expected to achieve a 21-year Life of Mine (LOM) from 2013 indicating a remaining LOM of around 13 years.
- **Peak Downs** is an open pit metallurgical coal mine producing 9 Mtpa and is owned by the BMA JV.
- **Poitrel** open pit mine is owned by the BMC JV and produces approximately 2 Mtpa of metallurgical coal.
- **Saraji** is an open cut coal mine owned by BMA and produces approximately 2.5 Mtpa of metallurgical coal.
- **South Walker Creek** open cut mine is operated by BMC and produces approximately 2.5Mtpa of coking coal.

Peabody

Peabody is a global coal producer with operations across the United States and Queensland and NSW in Australia. Peabody's share of coal mined at their operations was 4.5 Mt in Queensland in 2019 from their Bowen Basin project. They are the fifth largest coal producer in Australia producing both metallurgical and thermal coal.

Peabody's projects relevant to the Study area are:

- **North Goonyella** is owned by Peabody and is a 1.6Mtpa coking coal open pit mine.
- **Coppabella** is jointly owned by Peabody, CITIC Resources, Marubeni, Sojitz, Nippon Steel, and other investors and produces 2.2Mtpa (100% basis) from an open pit operation.
- **Moorvale** is part of the Coppabella joint venture and is hence owned partially by Peabody. This mine produced 1.6Mtpa (100% basis) in 2019.
- **Millennium** an open pit and underground mine is owned by Millennium Coal Pty Ltd. Which is a subsidiary of Peabody. It currently produces approximately 2Mtpa but is planned for expansion to 5.5Mtpa. It was expected to close in 2020 however was expanded to a mine life of around seven years and recently sold to MetRes which also purchased the Mavis Downs Mine.

Figure 54 – Peabody Bowen Coal Assets

(Source: KPMG analysis)

- **Middlemount** is an open pit mine owned 50% by Peabody and 50% by Yancoal and produces approximately 2.9 Mtpa (Peabody share 1.45Mtpa) of thermal and coking coal.

Anglo American

Anglo American is a multinational coal company with a focus on metallurgical coal and has three underground coal mines and two open cut operations in the Bowen Basin. Anglo American also has a number of key JV partnerships and growth projects in the region.

Anglo American's operations in the Study area are:

- **Capcoal** is a combination of the Capcoal open cut mine and the Grasstree underground longwall mining operation. Together these make up Capcoal which is a coking coal project capable of producing 15Mtpa from a region near Middlemount.
- **Dawson** is an open cut mine producing coking coal operated by Anglo American which has a controlling 51% interest in the project which is held in partnership with Mitsui Holdings. This mine has been producing since 1961 and now has an annual production of 4Mtpa.
- **Moranbah North** is an underground longwall mine producing metallurgical coal from the Goonyella seam with a mine life of 15 years. Anglo American owns 88% of this operation with 12% owned by a variety of other JV partners. Moranbah North produces approximately 8Mtpa.

Figure 55 – Anglo American coal assets
(Source: KPMG analysis)

- **Moranbah South** is a 50:50 JV between Anglo and Exxaro in the North Bowen. This project achieved Government approval in 2014 and is anticipated to be developed into a new underground longwall operation within the next 10 years.
- **Grosvenor** is an underground longwall coal mine which commenced operations in 2016 and is anticipated to achieve a mine life in excess of 30 years. It is located approximately 200Km south-west of Mackay and produces approximately 7Mtpa of coking coal.
- **Aquila** is a metallurgical coal project in the approvals stage and is intended to be a longwall underground mine wholly owned by Anglo American.

6.4 Comparing the Bowen & Surat Basins

Most important are the geological differences between the two basins. These geological differences impact the potential for development across the Bowen and make the development scenarios vary from what has been demonstrated in the much more developed Surat Basin developments. The major geological and productivity differences between the two basins include:

- Thicker coal seams, in conjunction with lower permeability in the Bowen Basin, allowing for horizontal well development to contact more of the coal surface. Horizontal well development has been used for several years in the Bowen and there is confidence that this method can be continued going forward. The cost of horizontal development is higher than vertical well development;

however due to the tighter coals in the Bowen Basin, horizontal wells will be required to reach the forecasted plateau rates.

- The Bowen Basin has four to six coal seams versus the 40 or more in the Surat Basin, and the Bowen coal is generally thicker than the Surat, meaning it can be developed with horizontal wells. A general rule based on economics would be to target seams 2m in thickness or greater with the horizontal wells.
- The Bowen coals also have steeper dips than the Surat coals, which creates narrow fairways of potential production. As an example, the Bowen may only be 5-10 productive locations wide versus 50 locations wide in the Surat. In addition, the Bowen has more faults and geologic unknowns than the Surat, resulting in greater variability of coal across the basin.
- The Bowen coals have lower permeability than those in the Surat. As a result, the Bowen coals produce both gas and water at lower rates, with lower individual well productivity. This results in the need for a greater number of wells, or longer horizontal wells, and thus incurs higher capital and operating cost for the same amount of gas produced.
- The Bowen coals generally have a higher gas content in the coal seams compared to the Surat. This is a positive, as it can require less coal contacted to produce more gas. However, as mentioned above, the higher gas content is often offset by the lower permeability, so whilst more gas exists for a given foot of coal contacted, the flow rates may still be lower than a similar foot of coal in the Surat.

Given the above commentary on the subsurface, the way the Bowen Basin will develop will be materially different to what occurred with the three CSG to LNG projects in the Surat Basin that were mostly developed over the last decade. The CSG to LNG projects were the largest coal seam gas developments globally, with many billions invested into wells and upstream production infrastructure, as well as some of the largest gas transmission pipelines developed in Australia. In contrast, the development of the Bowen Basin is expected to be more like the gas infrastructure that exists in the northern part of the Basin, replicated with a southern pipeline and gas gathering and production facilities that are of a similar scale to that at Moranbah.

As a result of these differences, the Bowen Basin is generally accepted to be a more difficult and more expensive play than the Surat Basin, reflected by the fact that Surat Basin acreage, and not Bowen, was developed to supply gas to the Gladstone LNG plants.

6.5 Existing infrastructure

6.5.1 Transport

In addition to supporting the development of the Bowen Basin through the transport of goods and services, the transport network is fundamentally important to the social and economic function of the region. As illustrated in Figure 56, the Bowen Basin is currently served by a combination of road, rail, port and air assets.

Table 6 summarises the existing transport infrastructure's baseline assessment and its capacity to facilitate the development of the Bowen Basin.

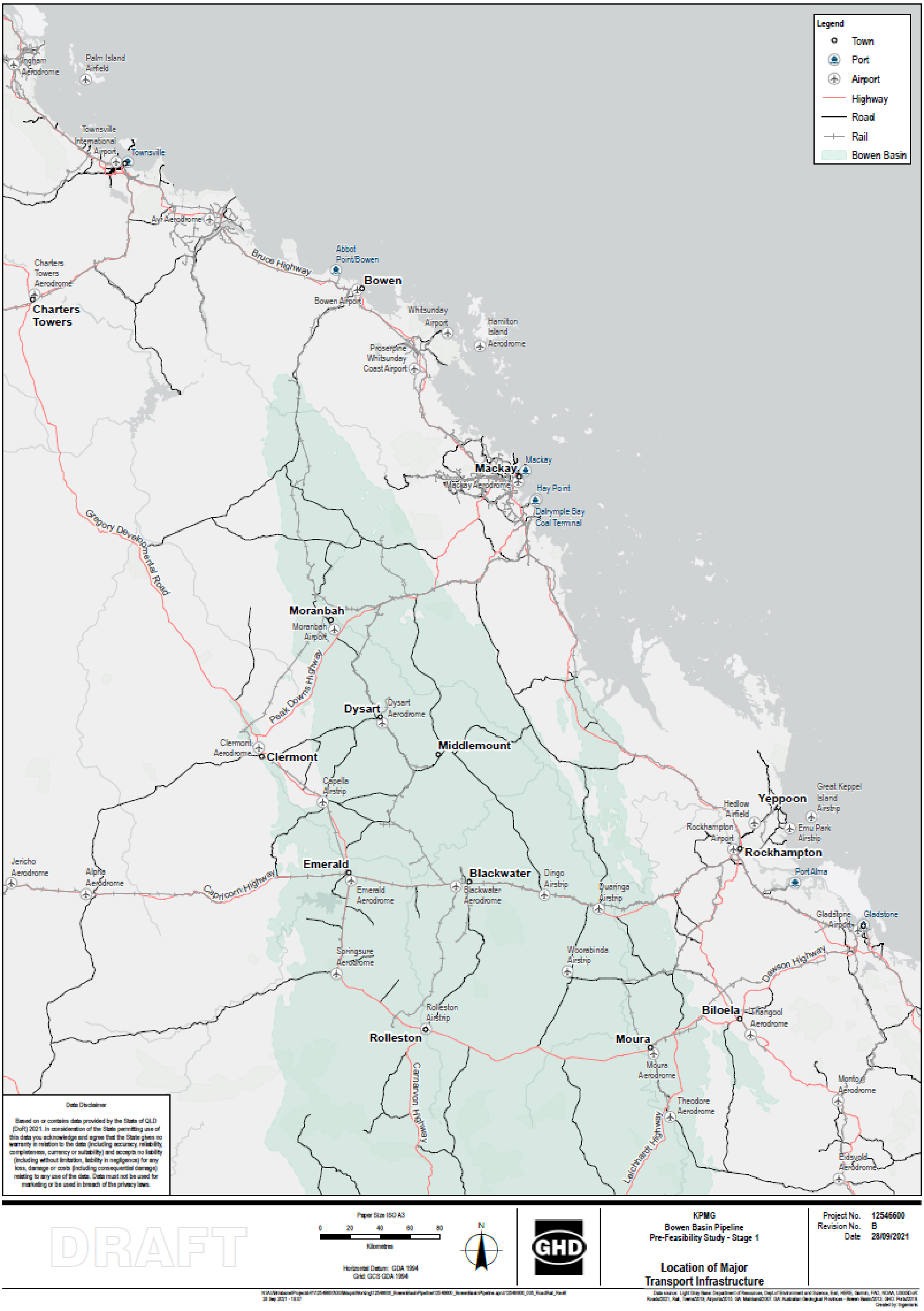


Figure 56 – Queensland Bowen Basin Logistics Map – Major Transport Infrastructure

(Source: GHD analysis)

Table 6 – Existing transport infrastructure
(Source: GHD analysis)

Infrastructure	Description	Current Standard / Capacity	Comments on Capacity
Ports			
Port of Gladstone	Existing large port facility with 20 wharves, predominantly used for coal (70M), LNG (23M) and alumina (6M) export, and bauxite (17M) and petroleum (1M) import.	FY20/21 total throughput 122M tonnes.	Spare LNG liquefaction and export capacity available, as at least 1 train on Curtis Island is not currently utilised (equivalent to ~600 TJ/d). Adequate import capacity for construction materials and line pipe.
Abbott Point	Existing large port facility near Bowen, for the export of coal. Expansion planned for Galilee Basin coal.	FY20/21 total throughput 30M tonnes, current export capacity 50M tonnes per year.	Spare capacity currently for coal export only.
Port of Hay Point	Existing large port facility, 40 km south of Mackay, for the export of coal, consisting of two terminals.	FY20/21 total throughput 46M tonnes.	Spare capacity currently for coal export only.
Port of Townsville	Existing port facility, predominantly used for coal, sugar and fertiliser export, and fuel import.	Annual total throughput FY19/20 7.6M tonnes, including 5.4M tonnes export.	Insufficient capacity for import of line pipe for construction. No facilities for export of LNG.
Port of Mackay	Existing port facility, with four wharves, predominantly used for coal and sugar export, and a small percentage (~5%) breakbulk.	Annual throughput FY20/21 3.2M tonnes, 160 ships. Total capacity approx. 6M tonnes per year, up to 600 ships.	May have capacity for import of line pipe for construction. No facilities for export of LNG.
Key Roads			
Bruce Highway	National Highway A1, extending the length of the Eastern Bowen Basin from Gladstone to Townsville.	Wide single lane, fully sealed.	Capacity available to support additional traffic.
Peak Downs Highway	State Route 70, extending from Mackay 280km southwest to Clermont.	Single lane, fully sealed	Peak Down Highway upgrade projects are currently in progress to accommodate increase in traffic. Primary access route for workers, fuel, machinery and other supplies to the coal mines of the Bowen Basin. Hazards include narrow two-lane highway only, frequently used for oversize loads, and fatigued workers.
Gregory Developmental Road/Highway	State Highway A7, from Mount Surprise 900km southeast to Springsure.	Single lane, sealed and unsealed	Insufficient capacity to support additional traffic. Pavement widening projects proposed by TMR.

Infrastructure	Description	Current Standard / Capacity	Comments on Capacity
Fitzroy Developmental Road	State Route 7, three separate sections from near Taroom, heading north to the Peak Downs Highway near Coppabella, totalling 454 km.	Single lane. Only northern section is fully sealed. Middle section partially sealed, southern section mostly unsealed.	Insufficient capacity to support additional traffic. Upgrade to two lane sealed road required including bridge crossings.
Bowen Developmental Road	State Route 77, from Bowen 259km southwest to Gregory Development Road at Belyando.	Single lane. Final 70km nearest to Belyando is unsealed.	Insufficient capacity to support additional traffic. Upgrade to two lane sealed road required including bridge crossings.
Suttor Developmental Road	State Route 11, from Peak Downs Highway near Nebo, 167 km west to Bowen Developmental Road near Belyando.	Single lane. Only the first 68km until North Goonyella mine near Elphinstone is sealed.	Insufficient capacity to support additional traffic. Upgrade to two lane sealed road required including bridge crossings.
Dawson Highway	State Route 60, from Gladstone 405 km west to Springsure via Rolleston	Single lane, fully sealed	Has minimal capacity to support additional traffic. Improved bridge crossings and structures required to accommodate prospective increase in fright traffic
Capricorn Highway	State Highway A4, from Rockhampton 575 km west to Barcaldine	Single lane, fully sealed	Increased capacity between Rockhampton and Gracemere. However, majority of the highway is single lane leading to capacity constraints.
Bowen Basin Access Roads	Multiple access roads to the Basin ranging from 5 km to 100 km	Low standard unsealed roads	Suitable for exploration only.
Rail			
Aurizon Central Queensland Coal Network (CQCN)	Connects Bowen Basin mines with major ports including Abbot Point, Hay Point and Gladstone. The network is mostly electrified.	Average total throughput of ~232 million tonnes per year (mtpa), predominantly coal. Main lines e.g., Blackwater to Rockhampton to Gladstone and Moranbah to Mackay have 5-10 mtpa available capacity.	There is some capacity for non-coal trains on the CQCN, including livestock, passenger, freight and light engine, as required by the Transport Infrastructure Act (1994). Potential to use spare capacity for transport of construction bulk, particularly pipeline construction materials.
Aerodromes			
Mackay Airport	Public airport, operated by Mackay Airport Pty Ltd.	~1M passengers per year and 15,000 aircraft movements, also has some cargo processing capacity, 2,000m runway.	Sufficient capacity for handling passengers and aircraft movements at present. It is forecasted that passenger numbers will be on the decline and there is spare capacity available with little capital investment.

Infrastructure	Description	Current Standard / Capacity	Comments on Capacity
Rockhampton Airport	Public airport, owned and operated by Rockhampton Regional Council.	~500k passengers per year and 10,000 aircraft movements, 2,600m runway	Sufficient capacity at present including planned terminal upgrades to improve passenger capacity.
Emerald Airport	Public airport, owned and operated by Central Highlands Regional Council (CHRC)	~250k passengers per year and 5,700 aircraft movements, 1,900m runway	CHRC are also responsible for several landing facilities, suitable for light aircraft, at Capella, Dingo, Duaringa, Rolleston and Springsure.
Moranbah Airport	Private airport, owned/operated BHP Mitsubishi Alliance.	~160,000 passengers per year, 1,500m sealed runway suitable for Dash-8 Q400 aircraft, (74 seats)	Capacity expansion needed for future with prospective increase in mining activities in the Bowen Basin
Middlemount Airport	Private airport, owned/operated Anglo American Coal	1,500m sealed runway suitable for Dash-8 Q400 aircraft, (74 seats)	Capacity expansion needed for future with prospective increase in mining activities in the Bowen Basin

When considering the need for transporting construction inputs required to support the development of the Bowen Basin, Table 7 summarises the limitations of the road, rail and port networks. As detailed below, road trains of up to 53.5m in total length may be used within Queensland to deliver dry bulk product to sites for either domestic and/or internationally imported freight from the two identified potential import gateways. However, break bulk product, such as tubing/pipeline, may be restricted to a Type 1 road train due to their long lengths.

Table 7 – Transport network limitations from product origin to site

(Source: GHD analysis)

Product origin	Road network		Train network	Port infrastructure
	Dry bulk	Break bulk (pipes)		
International				
Port of Gladstone	Road trains <53.5m	Type 1 road train	Axle weight limit 25 t Max train length of 1,800 m	Supports direct calling of import and export vessels. Max vessel length up to 320m, max depth 18.8m, beam 55m, displacement 140,000 mt.
Port of Mackay	Quad road trains	Type 1 road train	n/a	Supports direct calling of import and export vessels. Max vessel length 230m, max depth 13m, beam 33m, displacement 55,000 mt.
Domestic				
Local area	Quad road trains	Type 1 road train	n/a	n/a

6.5.2 Utilities

Power

As illustrated below in Figure 57, existing high-voltage transmission infrastructure is prevalent in the Bowen Basin, due to the existing established industrial users including coal mines.

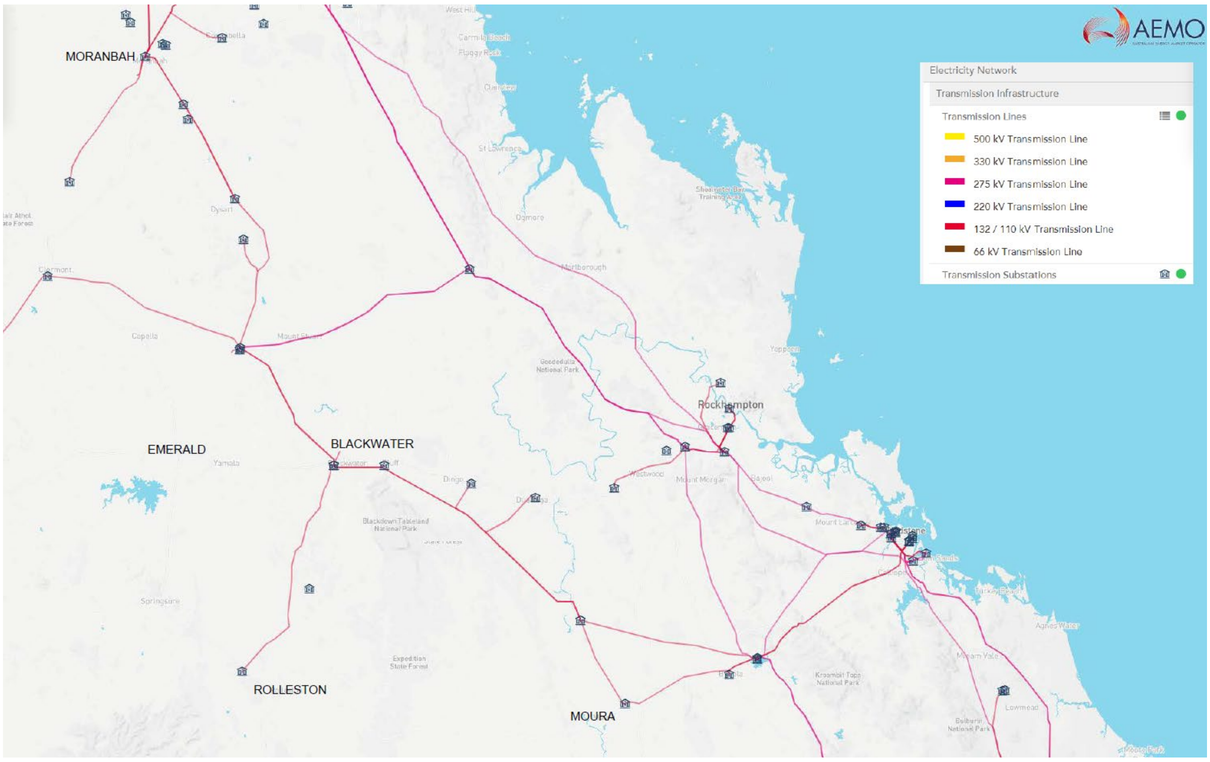


Figure 57 – Queensland HV transmission network
(Source: AEMO)

Additionally, as highlighted in Figure 58, the Bowen Basin region has recently seen an increase in renewable power generation, with several large-scale projects also in the planning and design phases to come online in the near future. Refer to Table 8 for a detailed list of power generation in the region.

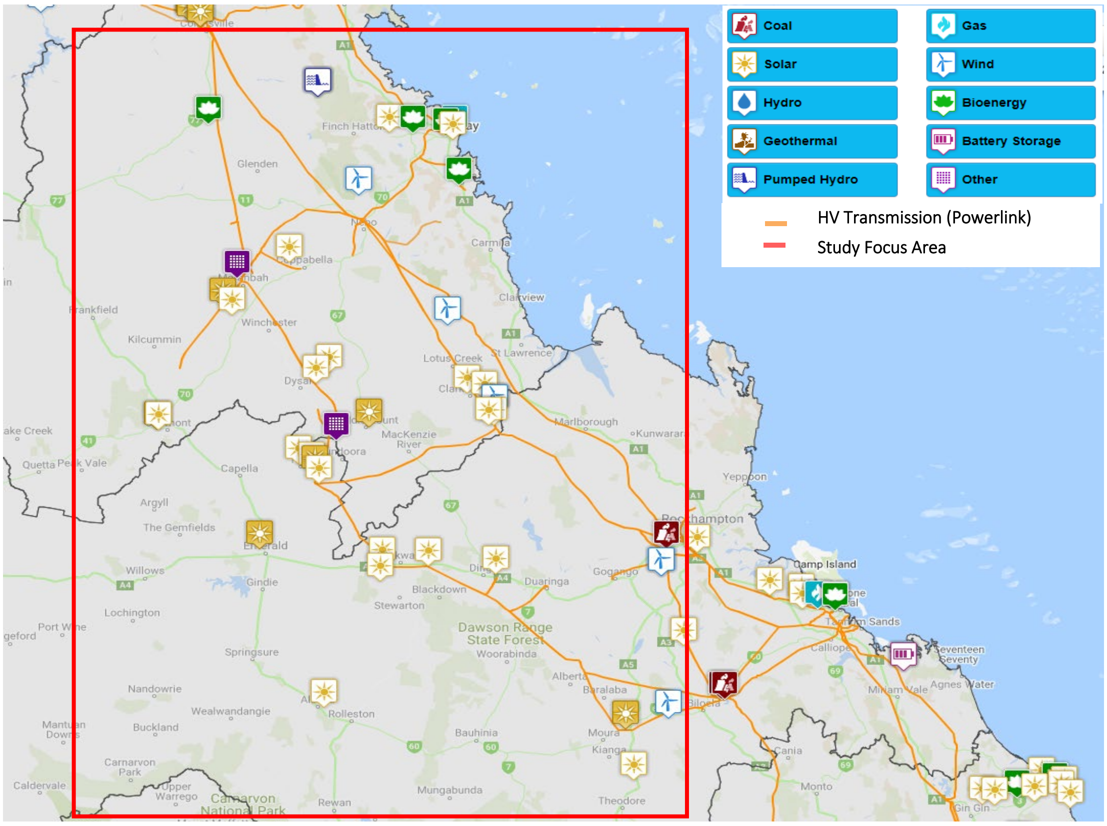


Figure 58 – Power generation assets in the Bowen Basin region
(Source: Department of Resources, Queensland Government)

Table 8 – Power generation facilities > 200 MW in the Bowen Basin, including existing and proposed assets

(Source: GHD analysis)

Name	Fuel	Owner	Year	Capacity (MW)	Status
Gladstone Power Station	Coal	NRG Gladstone Operating Services	1976	1,680	Existing
Bowen Renewable Energy Hub	Pumped hydro	RE Partners		1,500	Proposed
Stanwell	Coal	Stanwell Corporation	1993	1,460	Existing
Bowen Renewable Energy Hub	Solar	RE Partners		1,300	Proposed
Callide C	Coal	IG Power/Callide	2001	840	Existing
Callide B	Coal	CS Energy	1988	700	Existing
Bowen Renewable Energy Hub	Wind	RE Partners		500	Proposed
Clarke Creek Wind and Solar Farm (Stage 1)	Wind	Lacour		450	Under construction
Lotus Creek Wind Farm	Wind	Epuron		450	Proposed
Smoky Creek Solar Farm	Solar	Edify Energy		450	Proposed

Name	Fuel	Owner	Year	Capacity (MW)	Status
Clarke Creek Wind and Solar Farm (Stage 2)	Wind	Lacour		400	Proposed
Broadsound Solar Farm	Solar	Hadstone Energy		355	Proposed
Clarke Creek Solar Farm	Solar	Pacific Hydro		350	Proposed
Clarke Creek Wind and Solar Farm (Stage 2)	Solar	Lacour		315	Proposed
Aldoga Solar Farm	Solar	Acciona Energy		250	Proposed
Rodds Bay Solar Farm	Solar	Renew Estate		250	Proposed
Raglan Solar Farm	Solar	Eco Energy World		240	Proposed
Comet Solar Farm	Solar	Hadstone Energy		235	Proposed
Gregory Solar Farm	Solar	Renewable Energy Developments		215	Proposed
Bouldercombe Solar Farm	Solar	Eco Energy World		200	Proposed

Water and Waste management

Due to the extensive development within the Basin, the extensive existing water and waste management infrastructure is expected to be sufficient to support the gas industry.

6.5.3 Upstream gas infrastructure

Existing upstream gas infrastructure assets are concentrated in the north of Moranbah, and in the southern extent of the Study area. The upstream gas infrastructure includes the Moranbah Gas Project (MGP), the Westside production facility near Moura, and the Denison Gas production facilities in the Denison Trough to the north of Rolleston.

The MGP has been in operation since 2004 and is the prominent gas infrastructure within the northern region. Key features include:

- Four compression trains, each with a four-stage gas fired reciprocating compressor;
- A rated capacity of 68 TJ/day, with historical data indicating that typical flow rates range approximately between 25 to 30 TJ/day;
- Tri-ethylene glycol (TEG) package including TEG regeneration and an oily water separation system;
- Capability of compressing gas from 700 kPag to 13.0 MPag; and
- Raw gas supply to the MGP occurs via the adjacent Dyno Nobel Delivery Station which includes separation systems, gas metering stations and pressure regulation facility.

Westside's production facility near Moura is comprised of three central processing plants and three nodal compression stations. The nodal compression stations consist of inlet separation and compressions while the central processing plant consists of inlet separation, reciprocating compression, triethylene glycol (TEG) dehydration and coalescing filtration. The Moura Central Processing Plant (CPP) has an estimated capacity of 16 TJ/day while the Dawson River CPP and TEG capacity is rated at 9 TJ/day. Westside's production connects to the ECGM via a small pipeline that ties into the QGP near Moura and to the GLNG via a connection the GLNG Transmission Pipeline near to the connection into the QGP.

The Denison Gas production facilities in the Denison Trough to the north of Rolleston includes the Rolleston Gas Plant and Yellowbank Gas Plant in the South. The Rolleston Gas Plant includes a Dew Point Control Unit to remove hydrocarbon liquids from gas and compressor units for gas compression. Furthermore, the gas plant hosts an inlet separation unit and water handling facilities. Additionally, the condensate loadout system has been upgraded along with the refurbishment of site offices and camps. The Rolleston Gas Plant restarted in the year 2020 after being closed for approximately nine years. Current gas production from the Denison Trough, which includes both north and south gas processing facilities, is estimated to be approximately 20 TJ/day with a forecast of 60 TJ/day in the near term. The Denison Gas production connects to the East Coast Gas Market via a small pipeline that ties into the QGP near Rolleston.

6.5.4 Gas pipelines

The major existing pipelines in the Bowen Basin region, and associated technical details are listed in Table 9 and illustrated in Figure 59.

As shown in Figure 59, the existing pipelines are concentrated to the south, with some sparse gas infrastructure in the north, and limited infrastructure in the central region. This results in the large gas reserves in the region being unconnected to the ECGM.

Table 9 – Existing pipelines - Bowen Basin region

(Source: GHD analysis)

Pipeline	Length / Diameter	Total Capacity	Owner	Directionality / Route
North Queensland Gas Pipeline (NQGP)	391 km DN 300	108 TJ/d	Palisade	Single Moranbah to Townsville
Gladstone LNG (GLNG)	435 km DN 1050	1430 TJ/d	Santos	Single Wallumbilla to Gladstone
Queensland Gas Pipeline (QGP)	627 km DN 300	Northern: 145 TJ/d Southern: 37.2 TJ/d	Jemena	Bi-directional Wallumbilla to Gladstone
Australia Pacific LNG (APLNG)	530 km DN 1050	1560 TJ/d	APLNG (Joint Venture)	Single Wallumbilla to Gladstone
Wallumbilla Gladstone Pipeline (WGP, formerly QCLNG)	543 km DN 1050	1510 TJ/d	APA	Single Wallumbilla to Gladstone
Denison Pipeline (DP)	107 km DN 150	30 TJ/d	Denison Gas	Single Turkey Ck to Arcadia (QGP)
South West Queensland Pipeline (SWQP)	755 km + 182 km Looped – DN 400 & DN 450	Eastern: 340 TJ/d Western: 384 TJ/d (summer) 404 TJ/d (winter)	APA Group	Bi-directional Moomba to Wallumbilla
Roma Brisbane Pipeline (RBP)	438 km Looped – DN 250 & DN 400	Eastern: 210 TJ/d	APA Group	Bi-directional Roma (Wallumbilla) to Brisbane

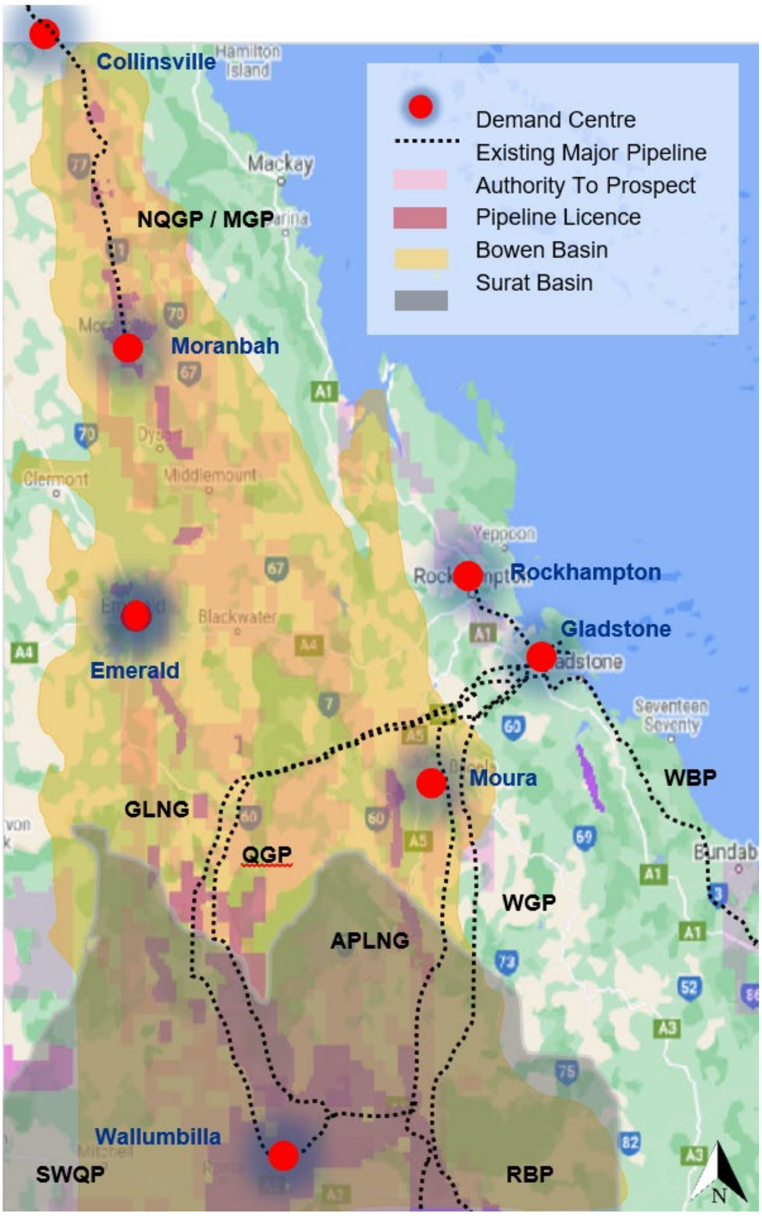


Figure 59 – Major existing pipelines in Bowen Basin
(Source: Queensland Government Open Data Portal (2020) https://www.data.qld.gov.au/dataset/queensland-mines-permits-current-web-map-service-json)

North Queensland Gas Pipeline

The North Queensland Gas Pipeline (NQGP), connecting Moranbah and Townsville, is the only transmission pipeline currently connected to the Bowen Basin.

The NQGP is comprised of a high-pressure pipeline from the Moranbah gas processing plant to the Townsville Power Station, a lateral pipeline connecting the pipeline to the Stuart Industrial precinct, and delivery facilities at Yabulu and Stuart.

The mainline of the NQGP is 391 km in length and a diameter of DN300 (12 inch), with capacity to supply 108 TJ/d from the Bowen Basin to Townsville.

The NQGP is currently owned by Palisade, after changing ownership multiple times since its construction by Enertrade (formerly owned by the Queensland Government) in 2004. The pipeline is currently operated by EIM, a company jointly owned by AGL and Arrow Energy.

The NQGP is a non-scheme pipeline under Part 23 of the National Gas Regulations, but previously had Category 2 and Category 3 exemptions. The pipeline was therefore exempt from information disclosure provisions, and from publishing service usage information, service availability information and financial information. Although the Category 2 exemption was revoked in May 2021, reporting has not yet been published, and therefore there is a lack of transparency on current operating and spare capacity of the pipeline.

6.5.5 CSG water infrastructure

The existing CSG Water Infrastructure in the central Bowen Basin comprises water management infrastructure constructed to support the Moranbah Gas Project. The Moranbah Gas Project commenced operations in 2004 producing gas for the domestic market supplying to the Townsville Power Station and industrial customers in north Queensland. To date, approximately 744 wells have been drilled with a network of approximately 180 kms of water gathering pipelines constructed from well heads to a network of eight lined aggregation dams. Water is transferred from the aggregation dams to two feed ponds to the 2 ML/d water treatment facility which is located at the Moranbah Gas Processing Facility. Treated water is supplied to a standard, suitable for irrigation and use by the adjacent Grosvenor mine. Brine from the water treatment process is stored in two brine ponds.

6.5.6 Infrastructure baseline implications

Transport

Existing enabling infrastructure such as ports, roads, railways and airports in the Bowen Basin are well equipped contributing to the region's economy and growth. There are five ports close to the Bowen Basin which includes the Port of Gladstone accommodating 20 wharves predominantly used for coal, LNG, alumina, Bauxite and petroleum imports and exports. Current throughput capacities of the ports in the vicinity of the Bowen Basin range from 3 million tonnes to 122 million tonnes with spare capacities for coal exports available at present. Some of the ports are potentially conducive to importing construction materials and line pipe.

With regards to access to roads and highways, the Bruce Highway is well connected and extends between Gladstone and Townsville thereby covering the eastern section of the Basin. The Peak Downs Highway is primarily used by workers for heavy hauling of machinery and offering supplies to the coal mines. Other roads, such as Fitzroy Developmental Road and Bowen Developmental Road, may require upgrading to two lanes to support additional traffic and bridge crossings.

The coal rail network in the Bowen Basin is operated by Aurizon. The Aurizon coal rail network links approximately 50 mines present in the Basin with major ports such as the Port of Gladstone, Abbott Point and Hay Point. With an average total throughput of approximately 232 million tonnes per annum of coal, there is additional capacity for non-coal trains to accommodate passengers, freight and construction equipment and materials.

Mackay Airport accommodates close to one million passengers every year and manages 15,000 aircraft movements along with cargo processing facilities. Comprising a runway length of 2,000 metres, the airport is capable of hosting small to medium sized aircraft, including cargo carriers. Several airports of leaner capacities, such as the Rockhampton Airport, Moranbah Airport and Middlemount Airport, offer improved connectivity within the Bowen Basin with some airports owned and operated by mining organisations.

Some of the limitations to transport networks include constraints on road train lengths, and weight and length limits on railway trains. Gladstone and Townsville ports are suitable for the supply of equipment and materials required for gas infrastructure development and have previously been used to import for resource projects in the Bowen Basin.

Utilities

The baseline assessment of the utilities within the Bowen Basin indicates that it will be able to support development without significant upgrades to wastewater and waste management facilities. The electricity requirements for gas development are also sufficient, although may require additional local distribution to new sites.

There is a general consensus amongst the coal mine operators in the Bowen Basin that high voltage transmission infrastructure is quite pervasive, however, operators have alluded to the fact that access to power continues to be a barrier as power linkage between facilities and high voltage power networks remains a challenge in many areas of the Bowen Basin. Additionally, the Bowen Basin region has recently seen an increase in renewable power generation, with several large-scale projects also in the planning and design phases to come online in the near future.

Upstream gas infrastructure

New gas process facilities and expansion of existing gas process facilities, and associated well pads and gathering systems, would be required to process additional gas development in the Basin. The extent and timing of these would be dependent on the timing and success of exploration programs.

Expansion of existing facilities is the quickest way to increase gas production, however this would need to be sufficiently close to the new areas of gas production, otherwise it is more economical to develop new facilities in close proximity to the gas wells. Whilst the proximity is relative and based on several factors, as an indication, it could be considered that 20 km to 30 km is the likely upper range for proximity of gas wells to gas process facilities. At these distances, the gathering system would require some form of nodal compression, that is, where several wells collect into a central location and the gas pressure is boosted to enable the coal seam gas to be moved over longer distances.

Gas pipelines

New export pipelines are required to transport gas from the Bowen Basin to market locations. These pipelines are required to be designed, constructed, and operated in accordance with the relevant Queensland Government legislation and to Australian Standard AS2885 Pipelines – Gas and liquid petroleum. Additionally, the gas export pipelines will be covered under the National Gas Law which regulates the commercial operation of pipelines in participating jurisdictions, which includes Queensland.

These pipelines will be required to transport the gas at high pressure due to the significant distances involved. Typical gas transmission pipeline systems within Australia required flow rates to range from moderate flows to high flows.

Consideration should be given for an infrastructure corridor for pipelines and other linear infrastructure, from the Bowen Basin to the market connection locations.

CSG water infrastructure

The CSG water infrastructure required will be developed as part of the gas production facilities for new production areas and expanded as required within the existing facilities, should the existing gas production facilities be expanded. The water rates expected for the Bowen Basin are materially lower per well than that seen in the Surat Basin, therefore the relative scale of the CSG water infrastructure will be less that that seen in the Surat Basin. There have been various configurations used for CSG water infrastructure since the development of the Moranbah Gas Project, and it is expected that each gas production proponent will develop a configuration that suits their project requirements. The produced water management will need to comply with the requirements of the approved development plans for the petroleum lease, and it is noted that the requirements on management of CSG water have changed over time. Given the use of raw water within coal mining operations, it is expected that a reasonable percentage of produced water will be able to be beneficially used in mining operations.

6.6 Socio-economic baseline

This section presents a baseline overview of the socio-demographics of the Bowen Basin and explores key themes, trends and outliers that may be relevant to consider in the context of any project impacts. The full baseline is provided in Appendix E.

As highlighted in Figure 60, the study area used to establish the baseline includes five local government areas (LGAs) which cover the Bowen Basin:

- Whitsunday LGA;
- Isaac LGA;
- Central Highlands LGA;
- Woorabinda LGA; and
- Banana LGA.

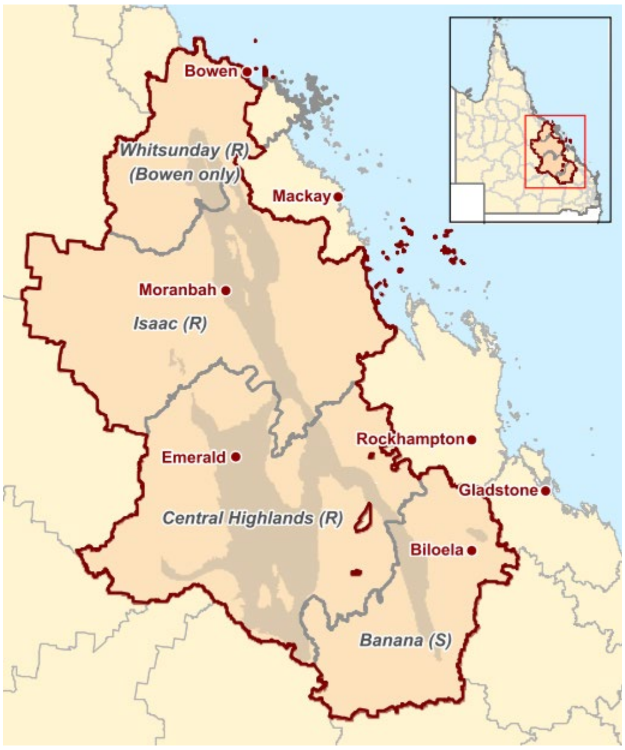


Figure 60 – Socio-economic study area

(Source: (Queensland Treasury, 2021)

As detailed in Table 10, in 2020, there are estimated to be 86,636 residents across the study area, which represents less than 1% of the Queensland population.[3] The study area is home to larger shares of children (aged 0-15) and working-aged residents (aged 30-64) than Queensland, while conversely the area has a smaller share of young workers (aged 15-29) and senior residents (aged 65+) than the Queensland average.[4]

This reflects an ongoing trend throughout regional Australia whereby young people leave rural areas and relocate to larger, urbanised areas to access employment, education and social opportunities. It may also indicate that the study area supports a larger proportion of workers who are raising families. Over the next 10 years to 2031, the study area is expected to grow at an average annual rate of 0.7%, which is slower than the state average of 1.7%.[5]

Most of the residents in the study area are located in Whitsunday LGA and Central Highlands LGA (41.5% and 33.2%, respectively), indicating larger labour forces to support industry activity. Whitsunday LGA contains the urban areas of Airlie Beach-Cannonvale and Bowen (9,334 and 8,851 residents, respectively), which are both located on the coast approximately 70 km outside of the Bowen Basin.[6] As such, these urban areas tend to support the established tourism sector (discussed below). The other urban areas of significance across the study area include Emerald in Central Highlands LGA, Moranbah in Isaac LGA, and Biloela in Banana LGA (13,529, 8,334 and 5,724 residents, respectively).[7] These are located within the Bowen Basin in close proximity to mining tenements and are more likely to support mining workforces. As such, workers for project construction are likely to be sourced from these towns.

[3] ABS.Stat, 2021, ERP by LGA (ASGS 2020)
[4] ABS, 2016 Census
[5] Queensland Government Population Projections, 2018 edition (medium series).
[6] ABS, 2016 Census
[7] ABS, 2016 Census

Woorabinda LGA is an Aboriginal Shire which encompasses a small geographical area (390km^2) of non-contiguous land and a small population (995 residents; 1.1% of the study area).[8,9] Woorabinda Shire has a significant Indigenous population (94.1%).

The study area has higher labour force participation rates[10] compared to Queensland (73.1% vs. 52.1%), as illustrated in Table 10.[11] The unemployment rate in the study area is lower than the state-wide average (4.5% vs. 7.3%).

Table 10 – Demographic summary

LGA	Estimated Resident Population (2020)		Indigenous Share of Total Population (2016)	Labour force (2021)	Participation rate (2019)*	Unemployed persons (2021)	Unemployment rate (2021)
Whitsunday	35,927	*41.5%*	4.9%	21,366	66.7%	1,425	6.7%
Isaac	20,987	*24.2%*	3.6%	12,987	76.6%	264	2.0%
Central Highlands	28,727	*33.2%*	4.3%	17,131	77.7%	717	4.2%
Woorabinda	995	*1.1%*	94.1%	592	87.2%	43	7.3%
Banana	14,065	*16.2%*	4.1%	8,412	74.8%	297	3.5%
Study area	**86,636**	***100%***	**5.2%**	**60,488**	**73.1%**	**2,746**	**4.5%**
Queensland	*5,176,186*		*4.0%*	*2,713,872*	*52.1%*	*197,348*	*7.3%*

**Participation rate for working age population 15 years and older.*

Sources: ABS.Stat, 2021, ERP by LGA (ASGS 2020), 2001 to 2020; Australian Government's Small Area Labour Markets (SALM) publication, March Quarter 2021; ABS, 3235.0 Regional Population by Age and Sex, Australia, June 2019.

In 2016, 98,000 residents in the study area were employed. Whitsunday LGA employs the largest number of local residents (33,782 workers; 34.5%) while Banana LGA employs the fewest (14,315 workers; 14.6%), except for Woorabinda LGA. As demonstrated Figure 61, the most common industry of employment was Mining, employing approximately one in five workers across the study area (20.4%; 9,122 workers) – significantly higher than the Queensland average (2.4%). This highlights that within the study area, mining represents a large industry specialisation, especially in Isaac LGA (38.7%; 3,759 workers) and Central Highlands LGA (25.2%; 3,269%). Within the Mining industry, Coal Mining employs the majority of workers (8,309 workers), while Oil and Gas Extraction employs the fewest (95 workers).

Other major industries by employment in the study area include Agriculture, Forestry and Fishing (12.6%), Accommodation and Food Services (9.6%) and Retail Trade (8.1%) in terms of employment, as shown in Figure 61. While Isaac LGA and Central Highlands LGA mainly support mining, Banana LGA specialises in Agriculture, Forestry and Fishing and Whitsunday LGA specialises in Accommodation and Food Services, which is a hallmark for tourism activity.

[8] ABS, 2019, 3218.0 Regional Population Growth, Australia 2018
[9] ABS.Stat, 2021, ERP by LGA (ASGS 2020), 2001 to 2020
[10] Aged 15 and over
[11] ABS, 3235.0 Regional Population by Age and Sex, Australia, June 2019

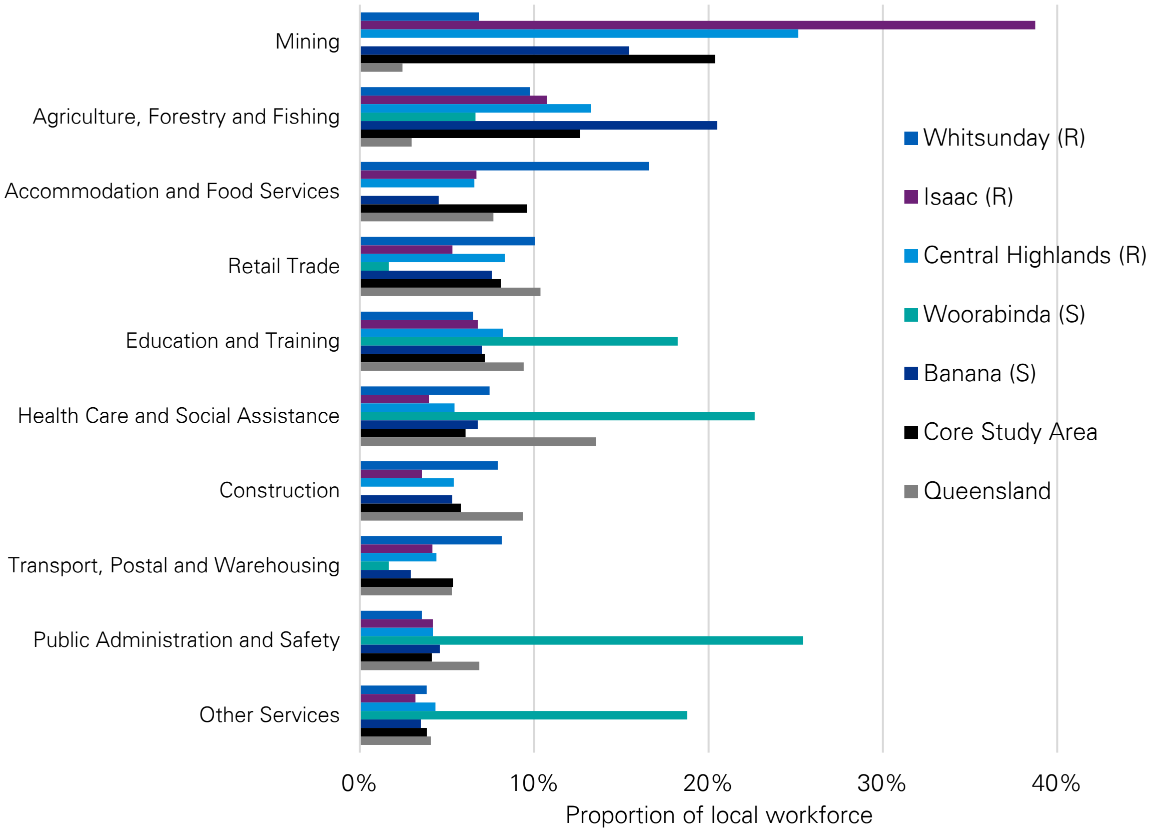


Figure 61 – Top ten industries by employment, place of usual residence

(Source: ABS, 2016 Census)

6.6.1 Socio-economic implications

The existing socio-economic profile of the Bowen Basin presents a challenge for the development of the Bowen Basin and the continued prosperity of the region. The demographic profiles reflect the ongoing trend throughout regional Australia, whereby young people leave rural areas and relocate to larger, urbanised areas to access employment, education and social opportunities. Coupled with lower-than-average population growth, higher-than-average labour force participation rates[12] and lower unemployment rates, it suggests that the Bowen Basin has limited latent capacity to support a construction workforce for new projects.

[12] Aged 15 and over

7. Bowen Basin production scenarios

The development scenarios for the Bowen Basin are based on the potential productivity of the coals in the Basin, and the economic recovery of reserves from those coals. The assessment has been informed by publicly available data. It is noted that significant explorative works have been undertaken by proponents in the study area, however, due to commercial confidentiality reasons, this information has not been used in the formation of the productivity scenarios. In lieu of industry data, testing of the productivity scenarios with industry has formed a critical input into the Study to ensure confidence in the results.

A model was developed that calculates the economic production of a single well with properties based on a number of inputs, then scaled to a whole-of-basin scenario by stacking individual wells to achieve a full field development profile.

The outputs of this model include a range of full field development production profiles for both gas and water, and the number of wells required to achieve that production. From this, infrastructure requirements, capital and operating costs can be developed to determine potential development pathways for the Basin (refer Section 9 for infrastructure details).

7.1 Production model inputs & assumptions

The development scenarios used for this Study have been informed by publicly available data that are layered with assumptions based on NSAI's experience of over two decades of technical work in the Bowen Basin. NSAI started the process by creating type curve forecasts to represent typical well production over the life of an individual development well in the Bowen Basin. The type curves were calibrated to actual production that has been released publicly on a per well basis, in addition to NSAI's knowledge of how Bowen Basin's CSG wells perform over time. There is a range of coal properties across the Basin that can affect the production rates of the coals, and NSAI have attempted to capture the wide range of outcomes with the different rates and plateau times. As a result, 12 type curves were modelled to incorporate four peak production rates as well as three plateau periods.

7.1.1 Natural gas price

The natural gas prices used to define the revenue-side of the model are taken from the analysis outlined in Section 4.2.3. The central mid-price scenario has been used to model the base case scenario as the mid-point average gas price.

Table 11 – Wellhead gas price cases

(Source: KPMG Analysis)

Case	Value
Low price	$5.00 / GJ
Mid price	$7.00 / GJ
High price	$9.00 / GJ

7.1.2 Production economics

In order to simulate the economic viability of an individual well, a model was created that incorporates capital expenditure, operational expenditure, revenue and taxes for an individual well. The model then simulates production from the well based on the geological factors outlined in Section 7.1.3, and costs applied on a production volume basis. This then provides a Net Present Value (NPV) for the well at a range of hurdle rates (discount factors).

Well economic life

Two main assumptions underpin the economic model of an individual well:

1. The Petroleum Resource Management System definition of reserves includes the requirement that all **reserves must be economic** and, therefore, gas price has a profound effect on the volumes of reserves in the Bowen Basin. If gas volumes cannot be drilled, completed and brought to market under a positive cash flow, they are not reserves.

2. As the gas volumes drop later in life, the economic limit will be reached and the wells will cease to contribute reserves to the overall value. A well's **production is capped when the NPV of the well drops to zero** as production declines and operational expenditure exceeds revenue.

Well CAPEX

Three well capital cost cases (well CAPEX) have been used in the development of the production scenarios in order to test economic viability of the scenarios at different well cost price points.

In upstream coal seam gas development projects, well CAPEX is the most significant cost to the developer given the high number of wells required over the life of a project. CSG developments can typically require the drilling of thousands of wells, and so small changes in well CAPEX can have a significant effect on the viability of projects.

The three well CAPEX price points have been selected based on current known drilling technologies, the types of wells likely to be required in the Bowen Basin and the known drilling costs of existing developments.

Table 12 – Well CAPEX cases
(Source: NSAI analysis)

Case	Value
Low cost	$1 million / well
Mid cost	$1.5 million / well
High cost	$2 million / well

Well OPEX

Well OPEX has been estimated based on experience and knowledge of the Basin to be $72,000 per well per annum. This OPEX incorporates the operation, maintenance and periodic workover of active wells in the development scenario.

Water handling

Water content of Bowen Basin coals is significantly lower than in the Surat Basin, where the water handling infrastructure is a large cost component of CSG development. Based on expected water production volumes and known geological properties of the Bowen Basin coals, an average water handling cost of $1.00 per barrel of water has been included in well economic calculations. This cost includes the handling, treatment, disposal and/or re-use of produced water within the project area(s).

Revenue

Each well is assigned a revenue stream that applies the wellhead price of natural gas ($5.00, $7.00 or $9.00 per GJ of production) to the total production of gas from that well. This is included in the well economic model as a monthly revenue stream based on monthly production volumes.

Taxes

The well economic model incorporates a nominal operating expense to approximate production-based taxes, e.g. petroleum resource rent taxes. Production-based taxes are applied at an all-inclusive rate of 6.35% of gross well revenue, where well revenue is gas price ($ / GJ) multiplied by the individual well's production (in GJ).

7.1.3 Geology

The Moranbah region (refer Section 7.3.2) currently produces gas from the MGP operated by Arrow Energy Pty Ltd. and is limited to a market of 50 TJ of gas per day. The key targets for development in the Moranbah region are the Moranbah Coal Measures (MCM), Fairhill Coal Measures and Rangal Coal Measures (RCM). Currently, gas is produced from the MCM and RCM. The Fort Cooper coals have little to no pilot data and therefore have not been included in this Study.

The Blackwater region (refer Section 7.3.2) has very little gas production and pilot data to assess potential for gas production in the key target zones. Subsurface mapping and regional geologic understanding show a narrow fairway requiring linear development. The key target zones in the Blackwater region are the MCM, Fairhill Coal Measures, RCM, German Creek Coal Measures and Burngrove Formation.

The Mahalo Region (refer Section 7.3.2) is a wider portion of the Basin with production on both sides. The key target zones in the Mahalo region are the Bandana Coal Measures, Baralaba Coal Measures, German Creek Coal Measures and Burngrove Formation. Current gas production in the south region is mostly from the Bandana and Baralaba Coal Measures.

Well productivity type curves

A number of individual well type curves have been developed based on existing knowledge of production, exploration and geology of the Bowen Basin across its various coal measures, geographical locations and coal properties, including permeability (refer Table 13 below). The basis for the modelled flowrates comes from data gathered from three main sources:

1. Press releases from developers, explorers and proponents over the course of Bowen development that point to production levels within the ranges modelled;
2. The production and well data supplied by the Queensland Government on a biannual basis; and
3. NSAI's experience within the Basin, which gives us confidence in the range.

The intent of the well type curves is to approximate the different productivities of the various coal measures in the Bowen Basin. After projecting the majority of all the active wells in the Basin, an internal understanding is gleaned of what these wells have produced under current conditions as well as what is realistic for future development.

Outlined in Table 13 below are the productivity cases used to generate the well type curves. Each well type curve is built up by combining a range of productivity variables:

- **Ramp rates** – have been assumed at six months for de-watering and reaching plateau production for an individual well, based on NSAI's experience in the Basin.
- **Well productivity** – three productivity cases have been defined based on NSAI's experience in the Basin, each of which were extensively tested with stakeholders that currently have exploration or production in the Basin. The low, mid and high productivity wells (0.26TJ/d, 0.53TJ/d and 1.06TJ/d) represent the range of coal types in the Basin and their varying productivity (due to different permeabilities, gas pressures, geological features etc.).
- **Production plateau length** – three different durations were tested to analyse well economic life. The three plateau lengths of two, four and six years represent the range of coal types in the Basin,

their initial gas in place volumes and pressures, the ability to operate these wells at peak production as a result, as well as how economic the wells remain as they decline.

Over 100 well type curves were calculated using the complete range of productivity variables in Table 13, and then combining them with the complete range of capital costs to drill and complete each well and the complete range of received gas prices.

Table 13 – Well productivity cases

(Source: NSAI analysis)

Case	**Ramp rate** *(time to reach plateau)*	Well productivity	Production plateau length
Low productivity	6 months	0.26 TJ/d per well	2 years 4 years 6 years
Mid productivity	6 months	0.53 TJ/d per well	2 years 4 years 6 years
High productivity	6 months	1.06 TJ/d per well	2 years 4 years 6 years

Drilling technology

Individual drilling techniques and technologies have not been explicitly modelled in the production scenario development. Rather, well CAPEX and OPEX has been estimated based on known current drilling technologies, such as targeted surface-to-inseam horizontal well drilling.

Well CAPEX has not been adjusted over the life of the development to capture variables, such as:

- Improvements in drilling technology that improve productivity;
- Improvements in drilling technology that lowers well CAPEX;
- Process improvements, efficiencies of scale and scope that lower well CAPEX and OPEX over time; or
- Escalation or inflation of costs that would increase well CAPEX or OPEX.

As the purpose of the scenarios is to provide comparative analysis of various scenarios, these variables are not considered material to the conclusions of the model and can be further explored in the subsequent phases of this Study.

Water production

Water production within the Bowen CSG development has been modelled for at 4,500 barrels a month peak rate and declining exponentially to a total volume of approximately 150,000 barrels per well. In the early development timeframe, we expect the water to take a more prominent role in the field. As the development matures, the volumes of water required to be produced before gas is released from the coals should be lowered. As more wells are drilled and the offset development drainage areas are de-watered, the continued development will support a reduced water volume overall. For the purposes of this exercise, we have assumed a consistent water volume for all development wells and have not assumed any benefit of Basin-wide de-watering.

7.2 Individual well type curves

Using the variables and fixed properties outlined in Section 7.1 and the mix of production plateau lengths given in Table 13, individual well type curves were developed. An *example* of nine individual well type curves is shown in Figure 62 below. These nine curves represent nine different combinations of the variables given in Table 13 at a fixed well CAPEX of $1 million, and a received gas price at the wellhead of $7.00/GJ. This figure is illustrative of the well type curves.

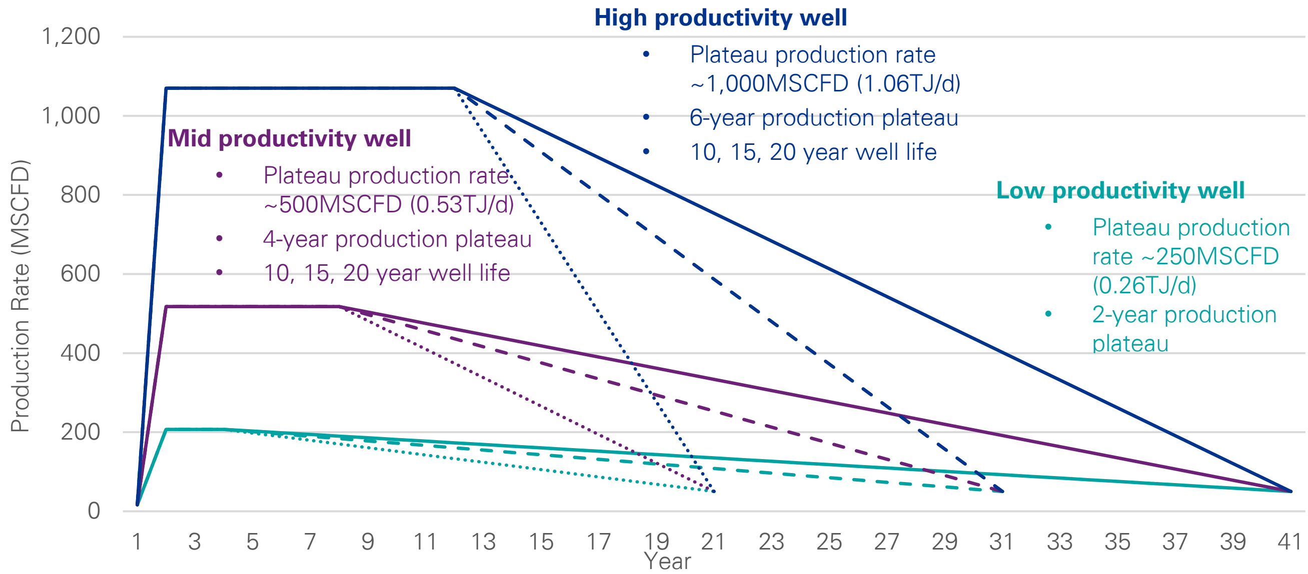


Figure 62 – Illustrative individual well type curves

(Source: NSAI analysis)

Table 14 below tabulates the individual well type curves and whether economic gas production is considered feasible for this combination of assumptions and inputs.

Table 14 – Individual well productivity cases – economic production matrix

(Source: NSAI analysis)

Wellhead gas price *(AUD$ / GJ)*	Well CAPEX *(AUD)*	Well productivity	Production Plateau Duration *(years)*	Economic production
$5.00 / GJ	$1 million	Poor	2	✗
			4	✗*
			6	✗*
		Average	2	✓
			4	✓
			6	✓
		Good	2	✓
			4	✓
			6	✓
	$1.5 million	Poor	2	✗
			4	✗
			6	✗
		Average	2	✓
			4	✓

Wellhead gas price *(AUD$ / GJ)*	Well CAPEX *(AUD)*	Well productivity	Production Plateau Duration *(years)*	Economic production
			6	✓
		Good	2	✓
			4	✓
			6	✓
	$2 million	Poor	2	✗
			4	✗
			6	✗
		Average	2	✓
			4	✓
			6	✓
		Good	2	✓
			4	✓
			6	✓
$7.00 / GJ	$1 million	All well type cases at a $1 million well CAPEX are economic for a $7.00 / GJ gas price		
	$1.5 million	Poor	2	✗
			4	✗*
			6	✗*
		Average	2	✓
			4	✓
			6	✓
		Good	2	✓
			4	✓
			6	✓
	$2 million	Poor	2	✗
			4	✗*
			6	✗*
		Average	2	✓
			4	✓
			6	✓
		Good	2	✓
			4	✓
			6	✓
$9.00 / GJ	$1 million	All well type cases at a $1 million well CAPEX are economic for a $9.00 / GJ gas price		
	$1.5 million	All well type cases at a $1.5 million well CAPEX are economic for a $9.00 / GJ gas price		
	$2 million	Poor	2	✗
			4	✗*
			6	✓

Wellhead gas price *(AUD$ / GJ)*	Well CAPEX *(AUD)*	Well productivity	Production Plateau Duration *(years)*	Economic production
		Average	2	✓
			4	✓
			6	✓
		Good	2	✓
			4	✓
			6	✓

** Case is negative value at PV10, but does generate positive net revenue*

7.3 Bowen Basin production scenario development

The individual well type curves were used as the basis for the modelling of a range of stacked well production profiles, generating a number of production scenarios to help determine whether there are economic scenarios that could help unlock the Bowen Basin. The development scenarios were run at a mixture of type curves to represent the coal variability across the three regions. We understand that the coal properties change and are not necessarily consistent from development drainage area to drainage area.

7.3.1 Stacked well productivity mixes

A number of different combinations of type curves have been stacked to achieve the targeted full field production plateau numbers outlined above.

Three production cases have been modelled – a low productivity case, a mid-productivity case and a high productivity case. These cases are made up of different mixes of individual well type curves as shown in Table 15 below.

Table 15 – Stacked well productivity mixes

Individual Well Type	Full Field Production Profile Case		
	Low Case	**Mid Case**	**High Case**
0.26TJ/d	50%	33.3%	-
0.53TJ/d	50%	33.3%	50%
1.06TJ/d	-	33.3%	50%
Average	0.4TJ/d	0.62TJ/d	0.8TJ/d

7.3.2 Regional segregation

As described in Section 6.1, the Bowen Basin covers a vast geographic area. Elongated in the north-south direction, the northern-most tip of the Basin is approximately 650 km from the southern-most tip. Across this distance, the coal measures in the Basin vary considerably, as does the amount and quality of subsurface data (including seismic survey, exploration wells, appraisal wells and production wells).

The **Moranbah region** to the north has considerable data, with existing CSG production from the Moranbah gas project operated by Arrow Energy.

Whilst a highly active coal mining area, the central **Blackwater region** (from Moranbah in the north to Blackwater in the south) has the least amount of subsurface data related to CSG resources.

The southern **Mahalo region** has been extensively explored, and there are projects advancing to the production stage.

As a result of the combination of varying levels of data (quantity and quality), and the several different coal measures within the Basin, the Bowen Basin production scenarios have been logically split into three main regions as outlined in Figure 63.

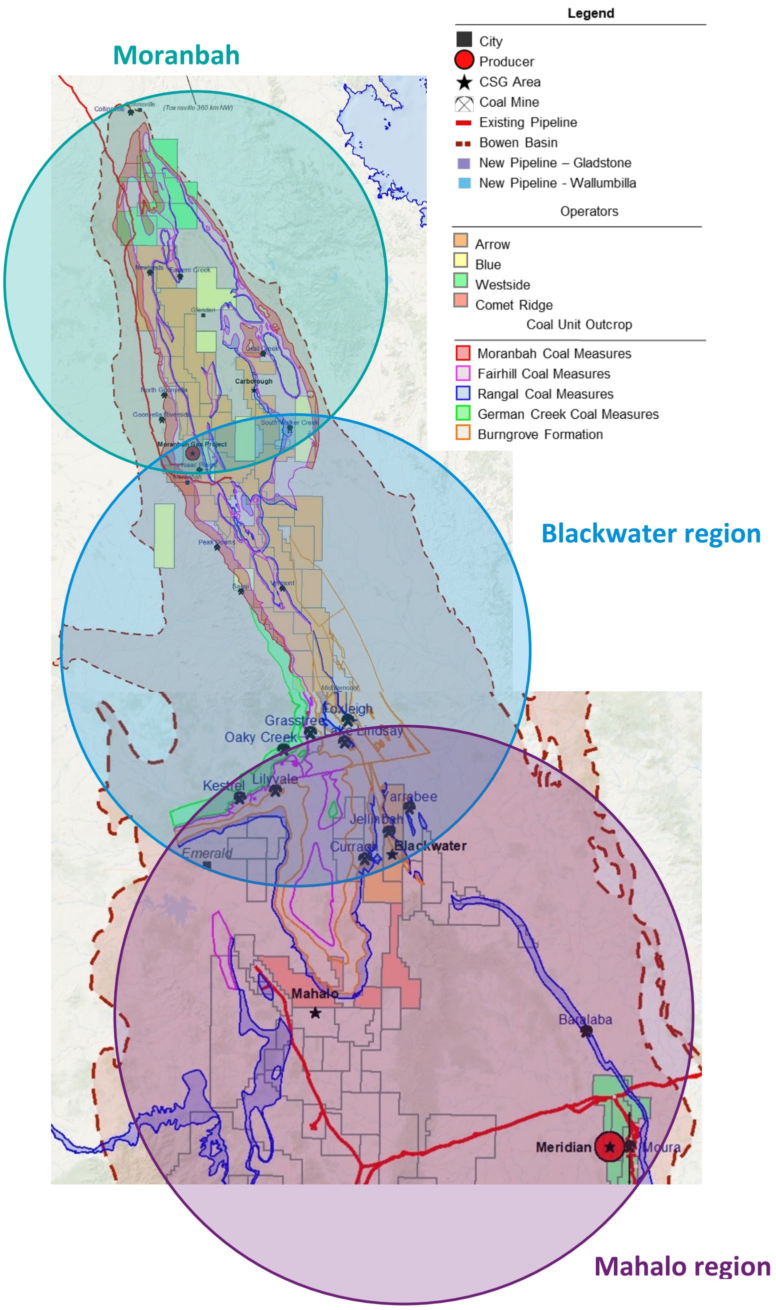


Figure 63 – Production scenario regions of the Bowen

(Source: NSAI Analysis)

Moranbah region

The Moranbah region centres on production from existing PLs and ATPs in the regions north of the township of Moranbah, utilising the existing Moranbah Gas Plant (operated by Arrow Energy) and the North Queensland Gas Pipeline (operated by Palisade).

The geology and productivity of the coals in this region are well understood, as CSG has been produced in this region since 2004.

Acreage in this region is predominantly held by Arrow Energy (currently producing from the Bowen Gas Project), Westside (currently exploring) and Blue Energy (in exploration and appraisal phase).

Whilst there is existing production in this region, challenging economics mean existing infrastructure is significantly under-utilised.

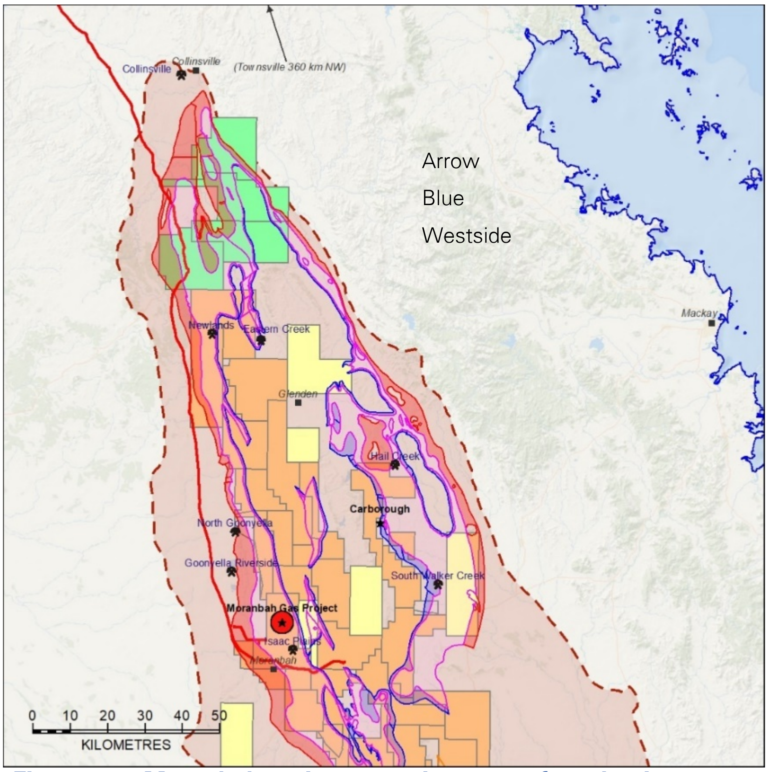


Figure 64 – Moranbah region scenario – area of production

(Source: NSAI analysis)

Blackwater region

The Blackwater region scenario centres on acreage held by Arrow Energy. This region of the Bowen Basin is the least explored and appraised section of the Basin and, as such, data quantity and quality is low.

Notwithstanding this, there are multiple major coal mines in this region, and so geological data exists that centres on coal production rather than gas. This has been used to develop the productivity model described in this report for the Blackwater region scenario.

Infrastructure to support gas development in this region is limited – currently no pipelines exist that could transport gas produced from this region to either Moranbah or the East Coast Gas Market. To unlock this region of the Basin would require a large capital investment in this enabling infrastructure, as well as a much more detailed exploration and appraisal campaign to confirm its prospectivity for commercial CSG production.

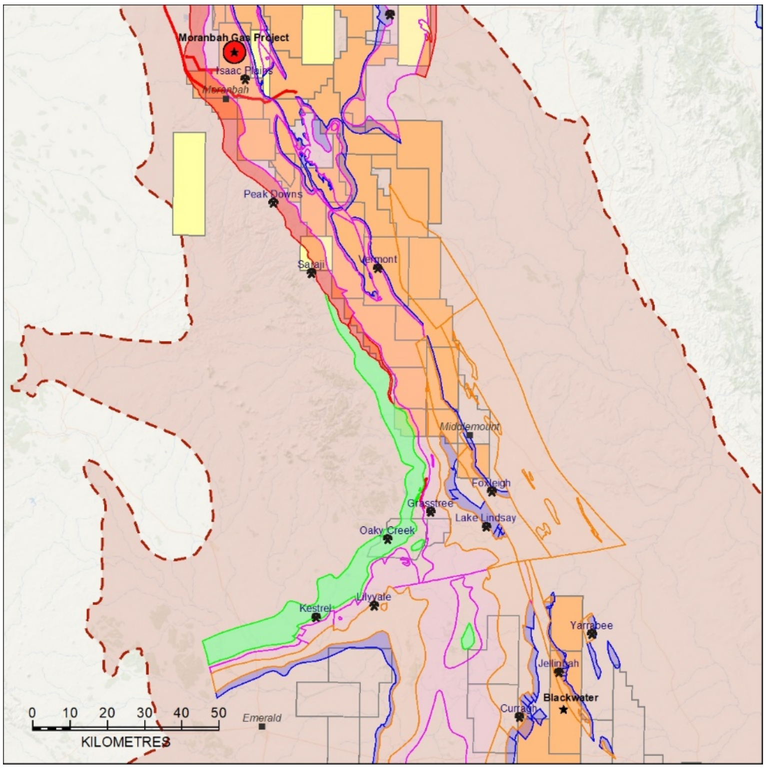


Figure 65 – Blackwater region scenario – area of production

(Source: NSAI analysis)

Mahalo region

The Mahalo region has numerous existing coal projects and some existing natural gas ATPs and PLs.

The region is covered under the DAWE (Department of Agriculture Water and the Environment) as the Mahalo SDA and existing approvals for CSG production are in place, with some of the most recent being in 2019.

The Mahalo region currently has over 95 gas wells, existing pipeline and compression facilities, and water management equipment.

Coal operations have been under way in the Mahalo region for decades and recently a precedent has been set for gas exploration activities with the Comet Ridge Mahalo gas project achieving full approvals.

Westside Corporation has a significant acreage position along the east side of the basin and produces approximately 40TJ per day from the Meridian project.

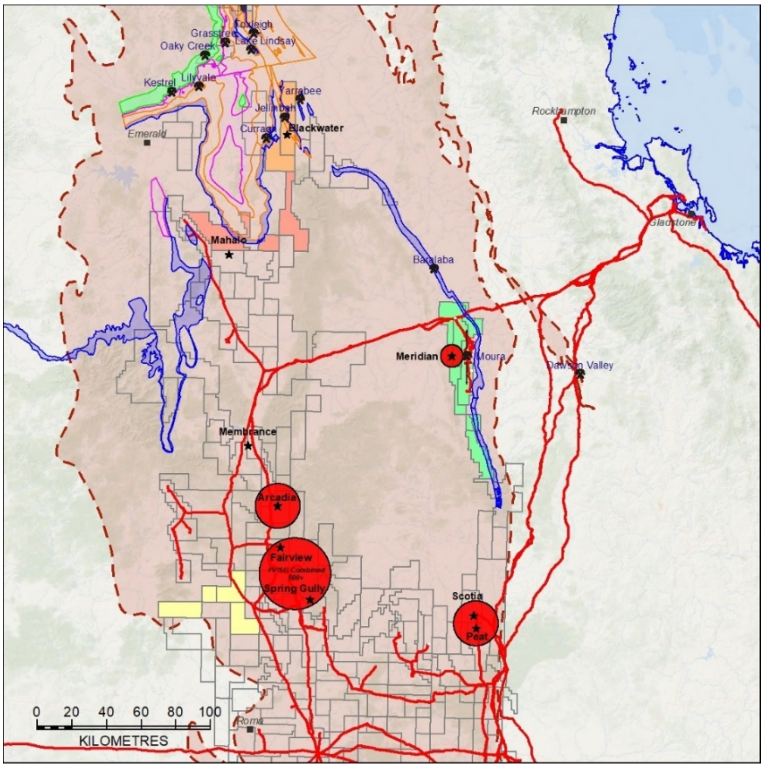


Figure 66 – Mahalo region scenario – area of production

(Source: NSAI analysis)

Arrow and Blue Energy also have large acreage holdings in this region and a number of further exploration tenements awaiting approvals.

7.3.3 Production targets by region

For this analysis, reasonable production targets were identified for each region, based on NSAI's experience in the Basin and confirmed through stakeholder consultation.

Moranbah region

In the Moranbah region, a *target rate* of 170 TJ of gas per day was used. Modelling indicates that this target can be achieved with drilling and completing 319 wells over the ramp-up phase of development. The well count could include existing wells once prior volume commitments have been fulfilled. To continue the plateau of 170 TJ of gas per day, additional wells are drilled as needed over the next 15 to 20 years. It is assumed that 50 TJ of gas per day will be sent to the domestic market in Townsville, and the remaining 125 TJ of gas per day will be transported south via a new pipeline. It is noted that the Moranbah region has several areas available for development with higher production potential than represented with the high case type curve wells, however the production model has been kept purposefully conservative given the concept level of this Study.

Blackwater region

The Blackwater region has the least amount of CSG production and pilot data and is considered to have the highest risk of development. A *target* of 70 TJ/day was used. Modelling indicates that this target can be achieved with 205 wells drilled and completed starting in 2030. Additional wells are drilled and completed as needed to maintain the 70 TJ of gas per day *target* over the next 15 to 20 years. This delay allows for further delineation and data gathering in the Blackwater region and also provides time to establish a firm gas supply in the Moranbah and Mahalo regions to provide economic support for pipeline investment.

Mahalo region

In the Mahalo region, a *target rate* of 170 TJ of gas per day was used. Modelling indicates that this target can be achieved with drilling and completing 319 wells over the ramp-up phase of development. To continue the plateau of 170 TJ of gas per day, additional wells are drilled as needed over the next 15 to 20 years. There are existing wells in the Mahalo region that could contribute to the total gas volume if prior volume commitments are fulfilled. The majority of gas volumes from this scenario are available for a pipeline going to southern markets via the ECGM. Similar to the Moranbah region scenario, the Mahalo region also has an area of development that the high-side type curve well could exceed.

7.3.4 Production timing and ramp rates

It will be necessary for drilling to start before any pipeline is ready to be able to load the line once it is ready and not have an extended period of little to no revenue for the pipeline. The ramp-up rates on a project basis (total number of wells) discussed below is related to current economics and the assumption of pipeline construction. The ramp up on an individual well basis is based on experience in the Basin and how the historical wells have de-watered. For the initial months of life, the wells produce mostly water with gradual increasing gas rates. It has been assumed that, if a market exists, the stakeholders will develop the wells to supply that market.

The number of wells that can be drilled in a certain timeframe is limited by the number of drilling rigs that can be deployed into the field, and the time taken to drill, complete and redeploy the rig for a single well. For the Mahalo region, there are also existing wells that can be incorporated into the ramp up to plateau quickly.

For the Moranbah region, the target rate is reached with a more prolonged build-up over two years by bringing on eight wells per month over that time period. It has not been assumed that existing wells will contribute to the total gas but, if they do, it will lower the number of wells required.

For the Mahalo region, there is an existing base of 208 wells that have been drilled and are ready to be brought into the system over the first six months. In addition to those wells, three wells per month are scheduled to come online to reach plateau and maintain the rate.

The Blackwater region brings on seven wells per month to reach the plateau. There are 169 wells drilled and ready to come online once the first years of linking in the Central area are reached.

7.3.5 Constructing a production scenario

A series of cases have been modelled using combinations of the above assumptions and inputs. In total, 108 cases were modelled and analysed.

The method for creating each case is outlined in Figure 67 overleaf. Fixed economic input assumptions, including well OPEX, water handling costs and tax costs, are combined with variable productivity, CAPEX and wellhead prices to model a range of potential production scenarios.

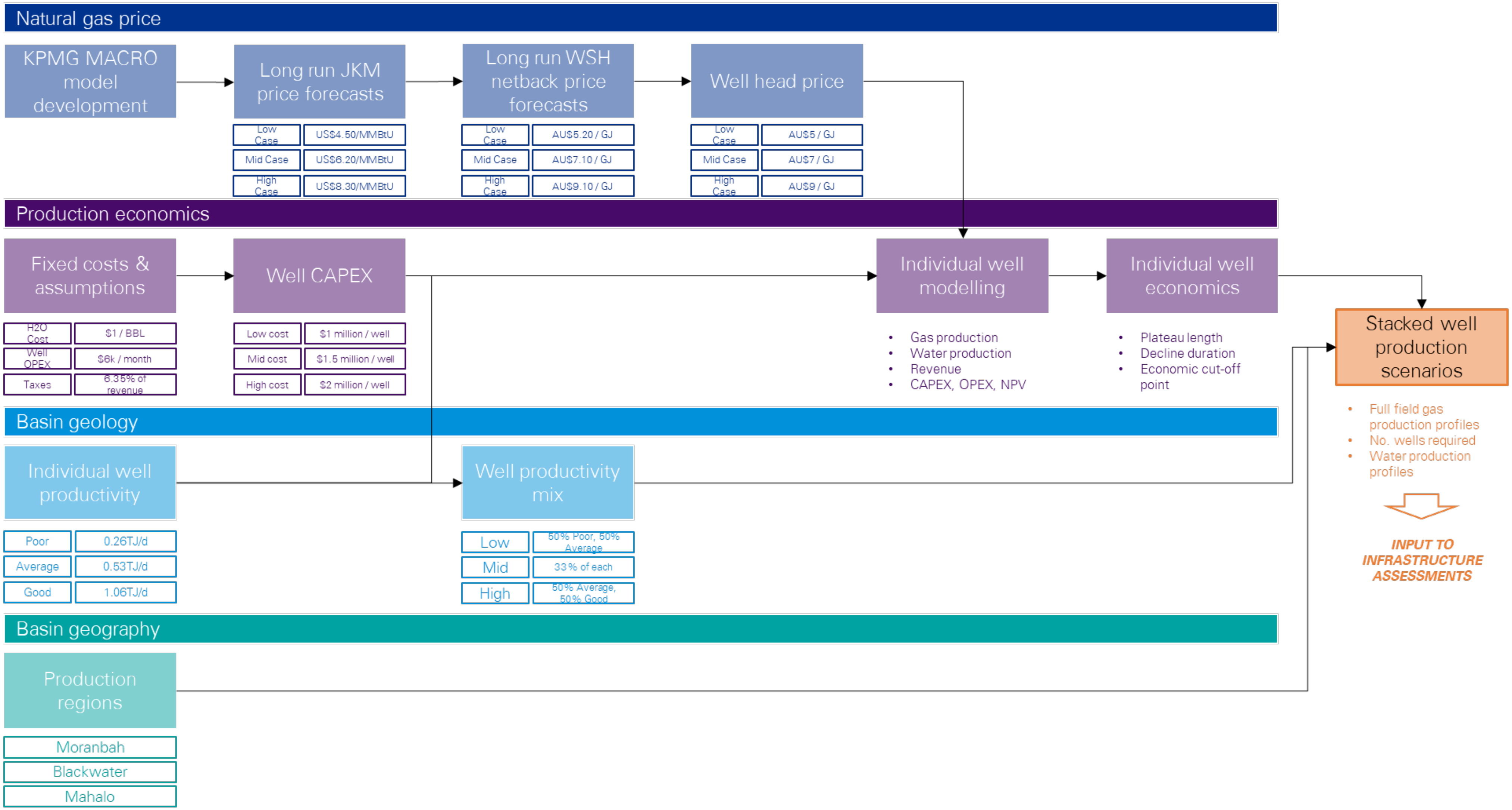


Figure 67 – Methodology for creating a development case

(Source: KPMG Analysis)

7.4 Bowen Basin production scenario results

7.4.1 Scenario 1 – Moranbah region

Scenario 1, the Moranbah region scenario, involves the development of acreage in the north of the Bowen Basin. This is an area with the most exploration, appraisal and production data and so production figures presented in this report have high confidence.

The premise of Scenario 1 is to develop up to 200TJ/d of gas, sending approximately 50TJ/d northwards via the existing Moranbah Gas Plant and the North Queensland Gas Pipeline, with the remaining 150TJ/d flowing south via new infrastructure to supply gas to the ECGM via Wallumbilla.

Depending on the productivity of the coals, between 699 and 1,348 wells are required at the peak, with production of approximately 200TJ/d achievable for a plateau duration of approximately seven to nine years (Figure 68).

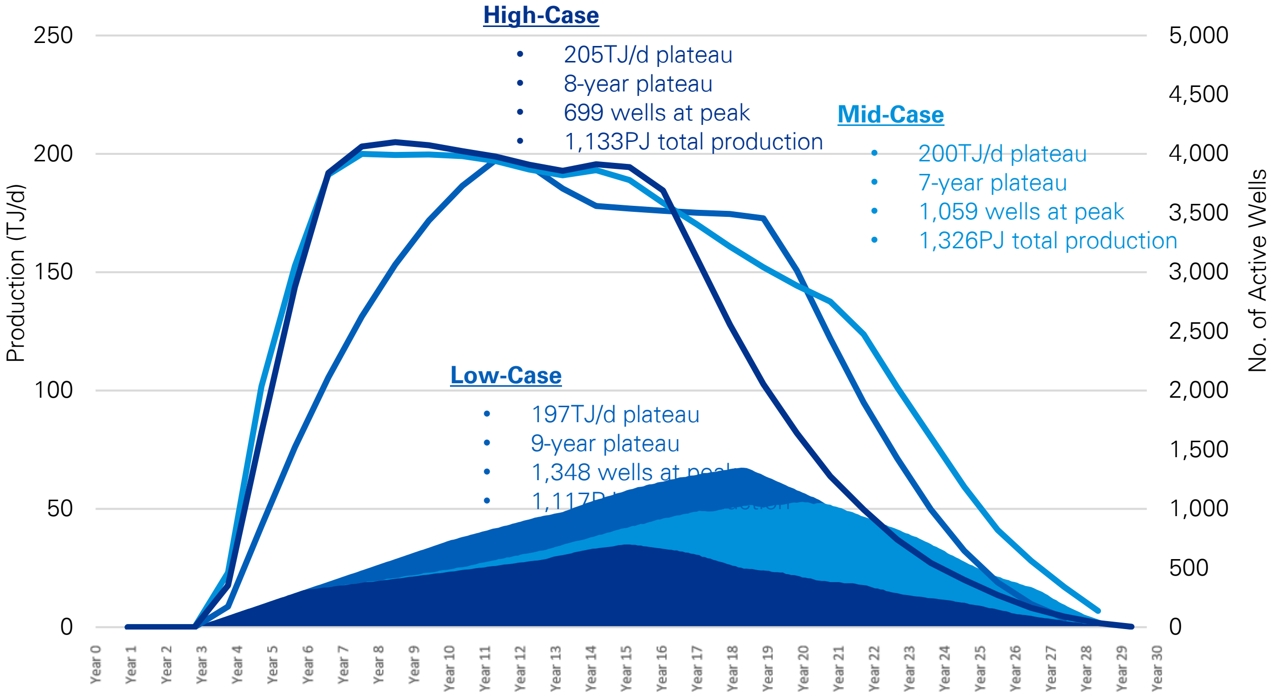


Figure 68 – Scenario 1 – Moranbah – gas production profiles

(Source: NSAI Analysis)

Water production in this scenario peaks at between 29kbwpd and 65kbwpd depending on well productivity, with total water production over the life of the field expected to be approximately 132mmbw to 324mmbw (Figure 69).

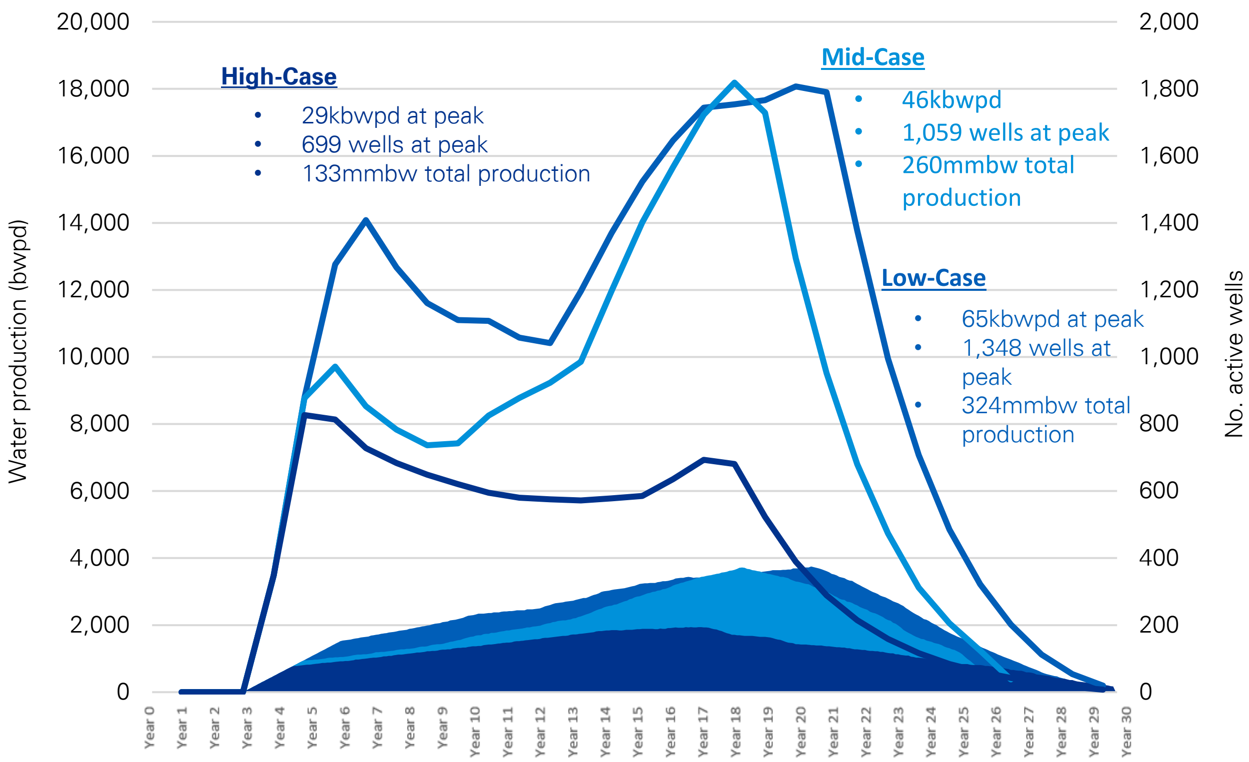


Figure 69 – Scenario 1 – Moranbah – water production profiles

(Source: NSAI Analysis)

7.4.2 Scenario 2 – Blackwater region

The Blackwater region scenario involves the development of natural gas infrastructure in the central portion of the Bowen Basin which is a narrow corridor of coal seams. This scenario would involve a production peak plateau of approximately 70TJ/day. This relatively low production target is due to the lack of current exploration and appraisal data of the coals in this region. Numerous regional coal players would also need to be engaged due to the potential overlap of interest between CSG players and existing mining leases/landholdings.

Depending on the productivity of the coals, between 240 and 632 wells are required at the peak, with production of approximately 80TJ/d achievable for a plateau duration of approximately seven to nine years (Figure 70).

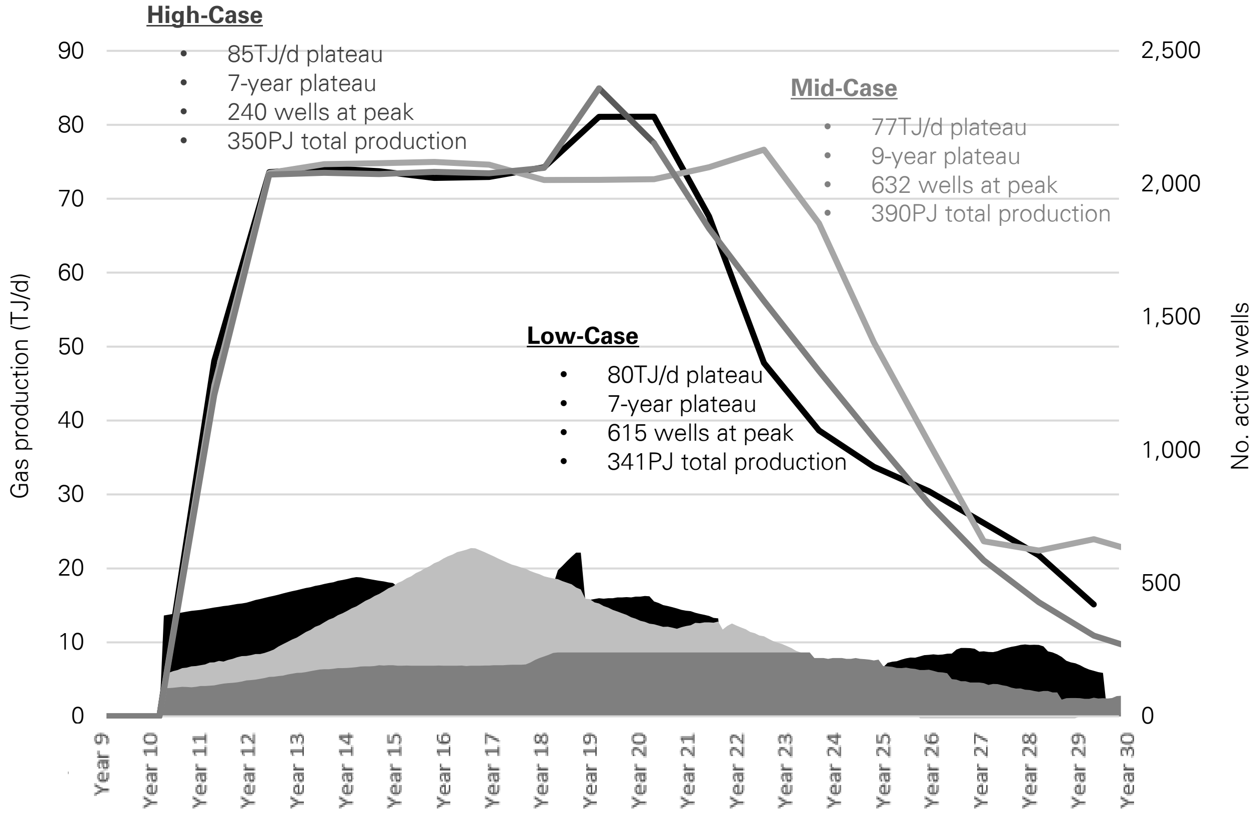


Figure 70 – Scenario 2 – Blackwater – gas production profiles

(Source: NSAI analysis)

Water production in this scenario peaks at between 14kbwpd and 50kbwpd depending on well productivity, with total water production over the life of the field expected to be approximately 45mmbw to 110mmbw (Figure 71).

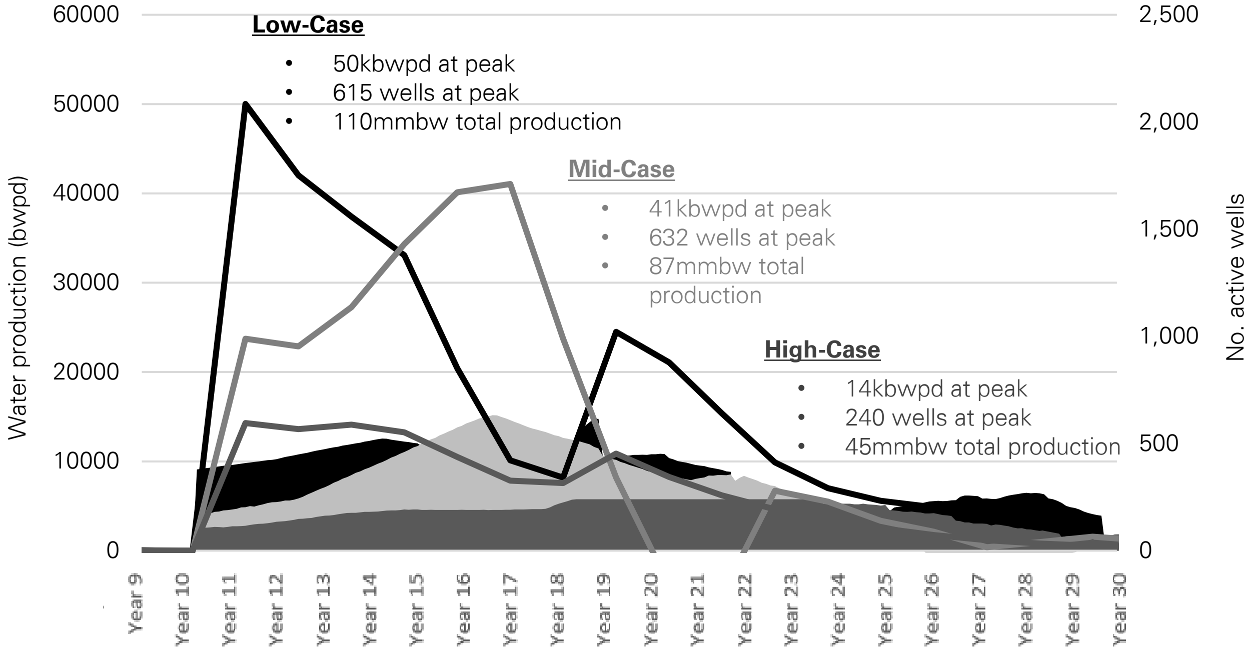


Figure 71 – Scenario 2 – Blackwater – water production profiles

(Source: NSAI Analysis)

7.4.3 Scenario 3 – Mahalo region

The Mahalo region scenario involves the development of the southern portion of the Bowen Basin to supply gas via pipeline to the ECGM through Wallumbilla.

This scenario is predicated on the development of many production facilities with substantial capacity and key production on both sides of the Basin. The highest production will be on the on the west side of the Basin in the (Greater Comet Ridge structure). The figure below illustrates the lower production rates and lower permeability coals on the east side (horizontal development), and the coals which do not outcrop in the far south (no colour-filled bands).

Depending on the productivity of the coals, between 643 and 1,365 wells are required at the peak, with production of approximately 180TJ/d achievable for a plateau duration of approximately 12 to 16 years (Figure 72).

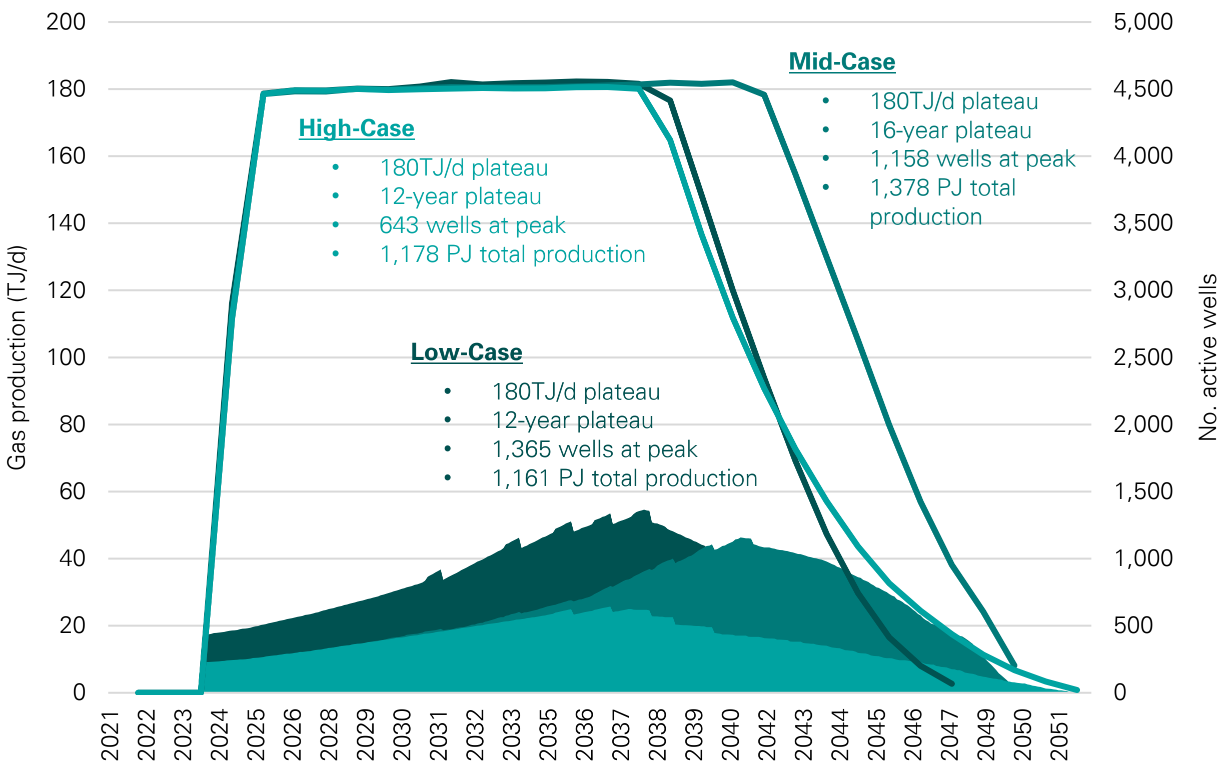


Figure 72 – Scenario 3 – Mahalo – gas production profiles

(Source: NSAI analysis)

Water production in this scenario peaks at between 29kbwpd and 65kbwpd depending on well productivity, with total water production over the life of the field expected to be approximately 132mmbw to 324mmbw (Figure 73).

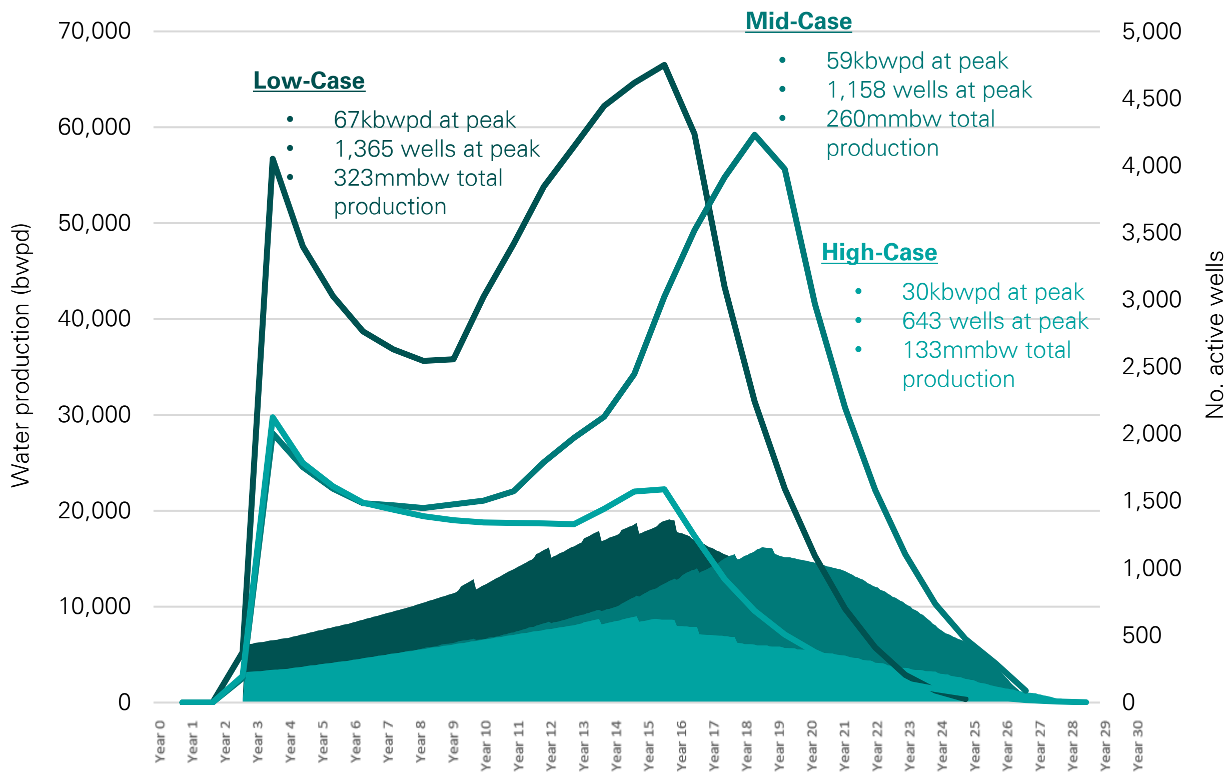


Figure 73 – Scenario 3 – Mahalo – water production profiles

(Source: NSAI analysis)

7.4.4 Scenario 4 – A staged approach for Mahalo and Blackwater regions

Scenario 4 combines both Scenarios 2 and 3 in a phased development approach. The Mahalo region would be developed initially, with a greenfield pipeline connecting the region to the ECGM. As the Mahalo area is developed and pipeline capacity is increasingly utilised, the pipeline would be extended northwards to the central area of the Bowen Basin.

This approach has two advantages compared to Scenarios 2 and 3 on their own:

1. The ability to de-risk development of the central area of the Bowen Basin (between Blackwater and Moranbah) by developing the Mahalo region first, with a lower CAPEX investment in transport infrastructure and upstream development.

2. The ability to further appraise the central region of the Bowen Basin, given its current lack of data related to CSG prospectivity. As the Mahalo region is developed, the central area could undergo a reasonable appraisal program and a stage-gate decision on when, or if, to extend the pipeline northwards could be taken based on this data.

Depending on the productivity of the coals, between 858 and 1,922 wells are required at the peak, with production of approximately 175TJ/d achievable during the first phase of development (Mahalo region), and 250TJ/d during the second phase of development (Mahalo region plus the Blackwater region) (Figure 74).

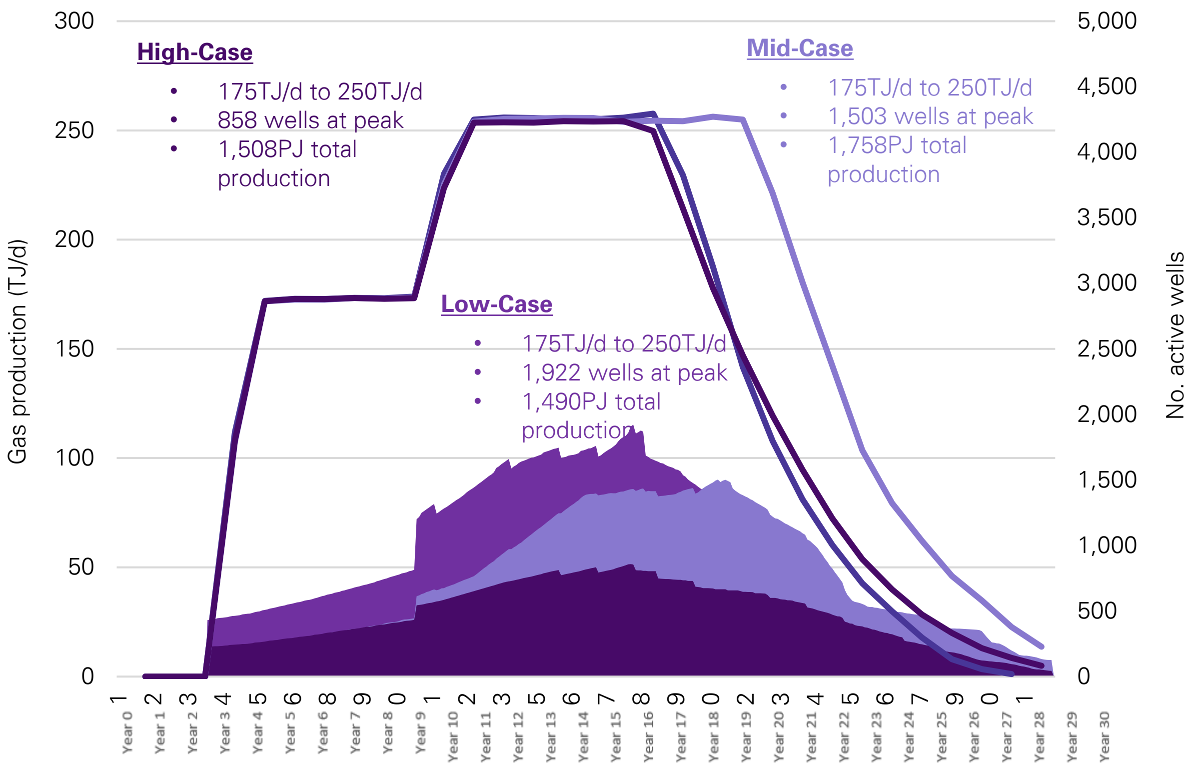


Figure 74 – Scenario 4 – Mahalo & Blackwater regions – gas production profiles

(Source: NSAI analysis)

Water production in this scenario peaks at between 33kbwpd and 92kbwpd depending on well productivity, with total water production over the life of the field expected to be approximately 177mmbw to 347mmbw (Figure 75).

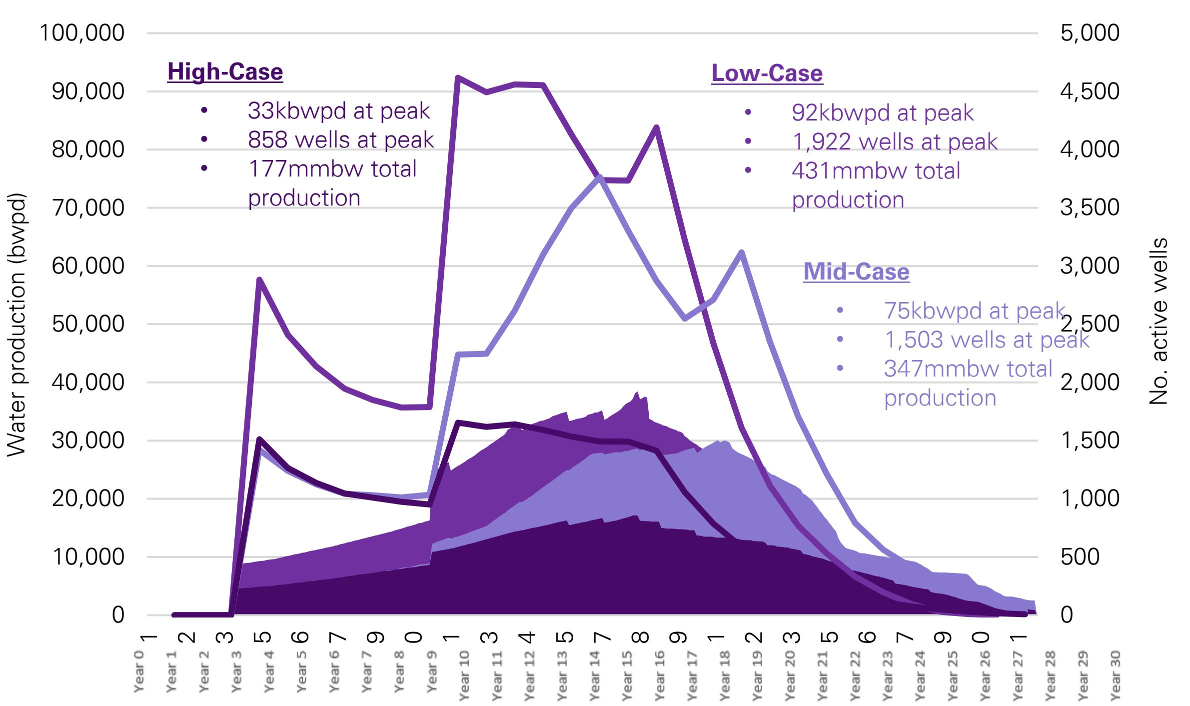


Figure 75 – Scenario 4 – Mahalo & Blackwater regions – water production profiles

(Source: NSAI analysis)

7.5 Summary

The production scenarios modelled, based on the inputs and assumptions developed through our existing knowledge of the Bowen Basin, publicly available data and stakeholder feedback, result in a number of pathways to economically produce natural gas from multiple regions in the Basin, as shown in Table 16 below:

Table 16 – Summary of the Bowen Basin production scenarios

Scenario	Productivity Case	Production Plateau *TJ/d*	No. Wells	Total Production *PJ*
Moranbah	Low	205	1,348	1,117
	Mid	200	1,059	1,326
	High	197	699	1,133
Blackwater	Low	80	615	341
	Mid	77	632	390
	High	85	240	350
Mahalo	Low	180	1,365	1,161
	Mid		1,158	1,378
	High		643	1,178
Mahalo + Blackwater	Low	175 – 250	1,922	1,490
	Mid		1,503	1,758
	High		858	1,508

The actual pathways to development may differ from these scenarios as technology improves, costs reduce, and further exploration and appraisal programs are prosecuted (particularly in the central region of the Bowen Basin between Moranbah and Blackwater). However, it is clear from the analysis conducted that it is achievable to unlock production from the Basin in volumes that will provide meaningful additional gas supplies to the ECGM, consumers in North Queensland (particularly Moranbah and Townsville) and potentially to the Gladstone LNG plants for export to trading partners in Asia.

8. Coal mine methane capture

Queensland's fugitive emissions, the greenhouse gases emitted during coal mining or gas extraction activities, have increased significantly over two decades. The Queensland State of the Environment Report (2020) confirmed that the outlook for gas and coal mining-based fugitive emissions was on the increase, and that fugitive emissions represented a sizeable portion of Queensland's total emissions (11-15%). As most of the associated emissions are methane, which has a higher greenhouse gas warming potential than CO_2, the impact of the mining and gas extraction sector on the regional anthropogenic carbon emissions is material.

While it is largely technically unfeasible with current viable systems and generally uneconomic to pursue many types of coal mine methane, such as that which is produced in shallow open pit operations, several types of coal mine methane have high potential for capture. These are traditionally in deep, open pit operations where pre-drainage gas is feasible for capture (deeper than 200m) and in underground mines where pre-drainage is previously carried out, however the products are largely under-utilised and could be brought to market as per the recommendation of this report.

The Bowen Basin, which has traditionally focused on coal production, has the potential to bring more gas to Queensland's domestic and export markets – by opening up areas for new (CSG) gas production and capturing unutilised gas from underground mines. However, the marked difference in CSG gas and incidental mine gas quality, unpredictability and variable flow rates are potential barriers to effectively scaling common use infrastructure.

Traditionally, mine operators have also been averse to either investing in new gas processing infrastructure or owning and operating that infrastructure. Generally, mine operators are supportive of power generation and moving surplus energy as "electrons" as opposed to "molecules". The current business landscape therefore suggests that policy drivers, improvements to the regulatory frameworks and cross-sector collaboration from both private and public sector players will be critical to the development of the Bowen Basin gas resources.

8.1 Defining Coal Mine Methane

Coal Mine Methane (CMM) refers specifically to methane released from coal seams and surrounding strata either just prior or during coal mining (i.e. mining activities). As the build-up of methane in underground mines can create both an explosive and an asphyxiation hazard for mining operations, the CMM must be removed prior to mining operations, and levels of residual methane in the mine kept below safe threshold limits. This is achieved through the use of ventilation systems (i.e. ventilation air methane) and/or dedicated relief systems (i.e. drilled boreholes) for surface treatment and/or dispersion.

8.1.1 Types of CMM

Pre-Drainage or SIS gas

The introduction of various gas drainage techniques in Australian gassy mines was necessary to complement ventilation system design and to satisfy statutory requirements in both open cut and underground mines. Gas pre-drainage can simultaneously reduce the risk of dangerous methane concentrations accumulating as well as reducing methane emissions into the atmosphere; moreover, the gas may be recovered as a valuable energy source for local power generation plants, as sales gas or other beneficiation.

Pre-drainage gas is usually of sufficient quality (>70-90% methane) that conventional treatment and upgrading techniques may be employed to produce pipeline quality gas with some additional unit processes. Where CSG tenements overlap coal tenements, there is opportunity for large-scale coal and CSG co-development as CSG extraction essentially provides drainage of gas for future mining projects.

While various methods and models exist for the estimation of gas liberated during extraction, actual realised volumes are dependent on a host of variables: drainage method, drilling technique, permeability of coal seams and strata, hydrogeology and gas migration. Nevertheless, it is proven that the most effective drainage method for high quality gas extraction is by pre-drainage: vertical or directional holes drilled from the surface, or horizontal longholes from developmental headings or in seam headings.

Open cut mine operational emissions

In open cut mines, fugitive emissions from mining operations occur due to the release of methane from coal extraction, coal transport, coal handling and size reduction operations. It occurs across the mine in a similar way to natural methane seepage. There are no requirements or practical methods for capturing this gas that is effectively emitted at atmospheric pressure. However, like underground mining, large volumes of pre-drainage gas are also produced, as this is the most efficient method of methane removal prior to mining and is necessary to manage for safety purposes.

Ventilation Air Methane (VAM)

VAM is by its nature predominantly air and is subject to strict quality controls to ensure the health and safety of mine workers. VAM is therefore not suitable as a recoverable resource using currently available and commercially viable technology.

Goaf gas

Goaf gas extraction, on the other hand, occurs after pre-drainage methods have maximised the removal of in situ gas through surface or in seam drilling methods. Goaf gas is a post drainage technique that occurs in parallel with mining activities and is critical to managing actual methane levels in underground atmospheres.

Goaf gas is generated during longwall cutting or extraction and principally from the caved gob that remains behind the advancing cutting face. Goaf gas therefore combines with a portion of ventilation air that is provided to the working area and does not typically produce gas of high quality for direct use. However, like pre-drainage systems, goaf gas extraction would require similar treatment, only to the extent and degree that secondary treatment processes increase to meet higher grade specifications.

Additional upgrading and cleaning technologies must be considered when coupling goaf gas extraction to either power or industrial sales gas offtakes.

8.2 Bowen Basin coal mine emissions

The coal mines in the Bowen Basin have a substantial annual greenhouse gas emissions footprint, which could be reduced via increased use of pre-drainage of gas and utilisation of goaf gas. Annual emissions data, outlined in Table 17, shows the largest emitting coal mines as identified by the Commonwealth Clean Energy Regulator, providing an indication of which mines have the largest potential for reduction in emissions through utilisation of CMM.

Table 17 – List of Queensland coal mines by annual emissions

(Source: Clean Energy Regulator (2021). 2019-20 Safeguard Facility Data. Australian Government)

Facility name	Company	Annual emissions *(tonnes CO_2-e)*
Capcoal Mine (note 1)	Anglo-American	3,149,800
Moranbah North Mine (note 1)	Anglo-American	2,318,893
Goonyella Broadmeadow Mine	BHP/BMA	1,273,036
Oaky Creek Coal Complex	Glencore	1,227,828
Grosvenor Mine	Anglo-American	1,185,349
Kestrel Mine	Kestrel Coal	970,726
Carborough Downs Coal Mine	Vale	656,281
Curragh Mine (note 1)	Coronado Global Resources	614,968
Blackwater Mine	BHP/BMA	592,875
Dawson Mine (note 1)	Anglo-American	570,556
Hail Creek Mine	Glencore	503,591
Peak Downs Mine	BHP/BMA	497,134
Newlands Coal Complex (inc. NN UG)	Glencore	434,665
Saraji Mine	BHP/BMA	417,183
Ensham Resources Minesite	Idemitsu Ensham Resources	402,871
Clermont Coal Operations	Glencore	381,970
South Walker Creek (note 1)	BHP/BMA	264,293
Jellinbah Mine	Jellinbah Group	246,250
North Goonyella Coal Mine	Peabody	243,234
Coppabella Coal Mine	Peabody	219,580
Middlemount Coal Mine	Yancoal	214,732
Foxleigh Mine	Qmetco	200,394
Poitrel Mine (note 1)	BHP/BMA	194,712
Yarrabee Coal Mine (Open Cut)	Yancoal	184,282
Rolleston Coal Mine	Glencore	166,843
Collinsville Mine	Glencore	153,071
Isaac Plains Coal Mine	Stanmore Coal	111,665
Total		**16,740,501**

1. *Data for some listed mines was sourced from Safeguard's multi-year emissions monitoring period, from 2016-2019. For these mines, the most recent annual covered emissions value was used in the table above, typically FY2019-20.*

Figure 76 indicates the CO_2 emissions from various coal mines in the Bowen Basin. From the map, it can be inferred that CO_2 emissions are the highest in the central Moranbah and Middlemount regions. Data related to CO_2 emissions were obtained from the Clean Energy Regulator (CER) website which is an independent statutory authority responsible for administering legislation to reduce carbon emissions and increase the use of clean energy in Australia.

8.2.1 Future mines planned in the Bowen Basin

Currently, it is estimated that there are a total of three mines that are planned to be constructed and operated in the coming years. These mines are proposed to be located close to the central region of Moranbah and Middlemount. Planned projects and their proposed coal production estimates are listed below:

- Olive Downs Coking Coal Project (Central Moranbah region) – 15 Mtpa;
- Winchester South Project (Central Moranbah region) – 11 Mtpa; and
- Valeria Coal Mine Project (Middlemount region) – 20 Mtpa.

All three mines are proposed to be open-cut type with construction to begin early in the decade and production to ramp up by 2025-2026. Analysis on gas emissions and methane capture from these proposed coal mines are not considered in this report. It is hypothesised that production life of several existing coal mines could be coming to an end and thus new mines' CMM will be offset by the reduction is current levels of CMM gas production.

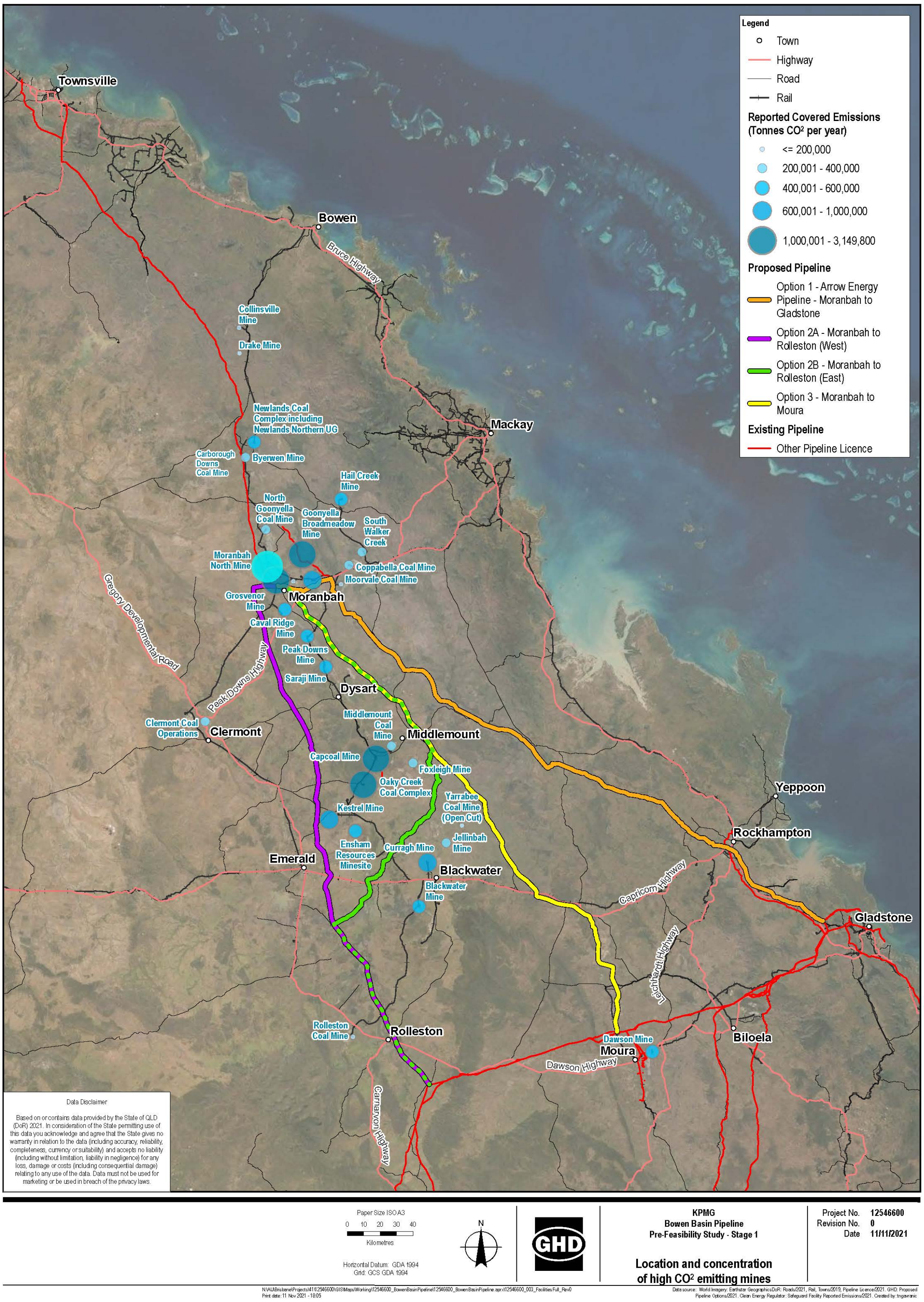


Figure 76 - CO_2 emissions by coal mine

(GHD analysis)

8.3 Modelling fugitive emissions from CMM

CMM emissions data was primarily based on gas production estimates as a derivative of coal production data available for individual mines in the Bowen Basin. Coal production data was acquired from the Queensland Government "Open Data Portal". These production estimates were for a designated period from 2015 to 2020.

Based on research and historical recovery data on CMM from various sources, tested with industry stakeholder feedback, the average CMM produced per tonne of coal produced (ROM production) was determined, with upper and lower quartile ranges to reflect the levels of uncertainty in the gas production volumes due to different coal gas contents across the Basin, as well as different mining techniques (Table 18).

Table 18 – Average gas production per tonne of coal produced

(Source: KPMG analysis)

Methane Production	Lower quartile	Average range	Upper quartile
Open Cut Mines	1 m^3/t	2.5 – 3.5 m^3/t	5 m^3/t
Underground Mines	9 m^3/t	11 – 12.5 m^3/t	14 m^3/t

CMM emissions by source were calculated as a percentage of total gas production per annum and were categorised into the following:

1. Open-Cut Mines:
    a. Pre-Drainage Gas (35%)
    b. Operational fugitive emissions (65%)
2. Underground Mines:
    a. Pre-Drainage Gas (35%)
    b. Goaf Gas (15%)
    c. Ventilation Air Methane (VAM) (50%)

Figure 77 below estimates yearly fugitive emissions (in CO_2-e) from regular operation of existing open cut and underground coal mine operations. As indicated, the annual fugitive emissions of existing underground mines in CO_2-e are estimated at approximately 9.5-10mtpa with a low and high case average of 7.25Mtpa and 11.25Mtpa respectively.

Figure 78 dissects these total emissions by source/type for a given year (2030). Of the 29mt of CO2-e forecast to be released (assuming no CMM capture), 19mt is from open cut operations, 3.5mt from pre-drainage, 1.5mt from goaf gas and 5mt from VAM.

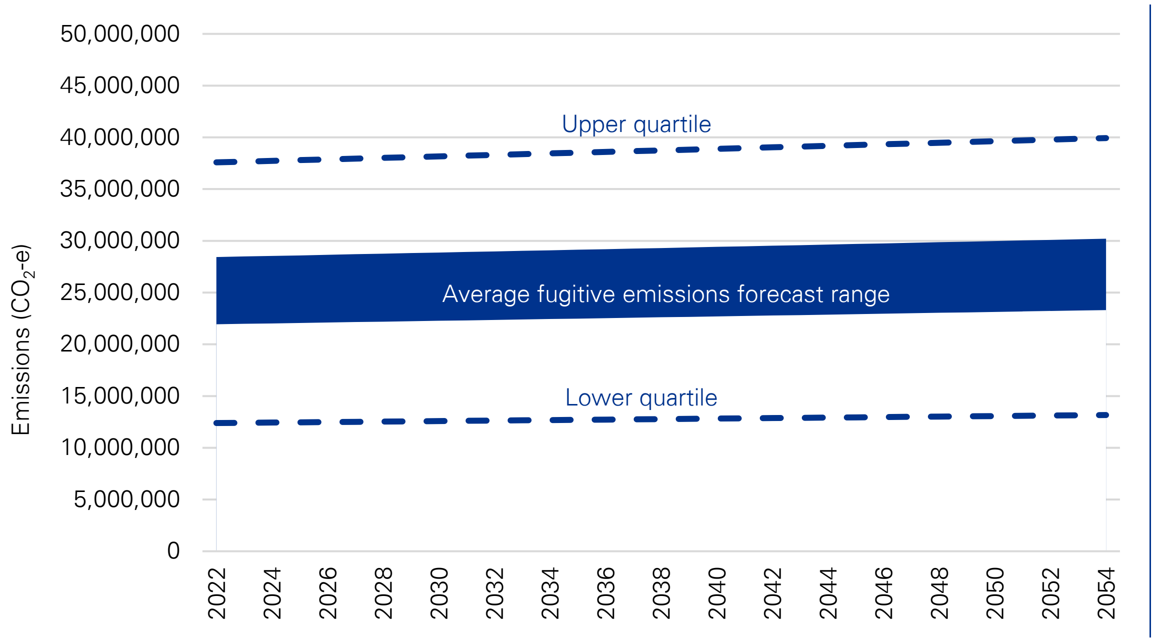


Figure 77 - Estimated total Underground and Open Cut and Underground Coal Mine Fugitive Emissions 2022-2054

(Source: KPMG analysis)

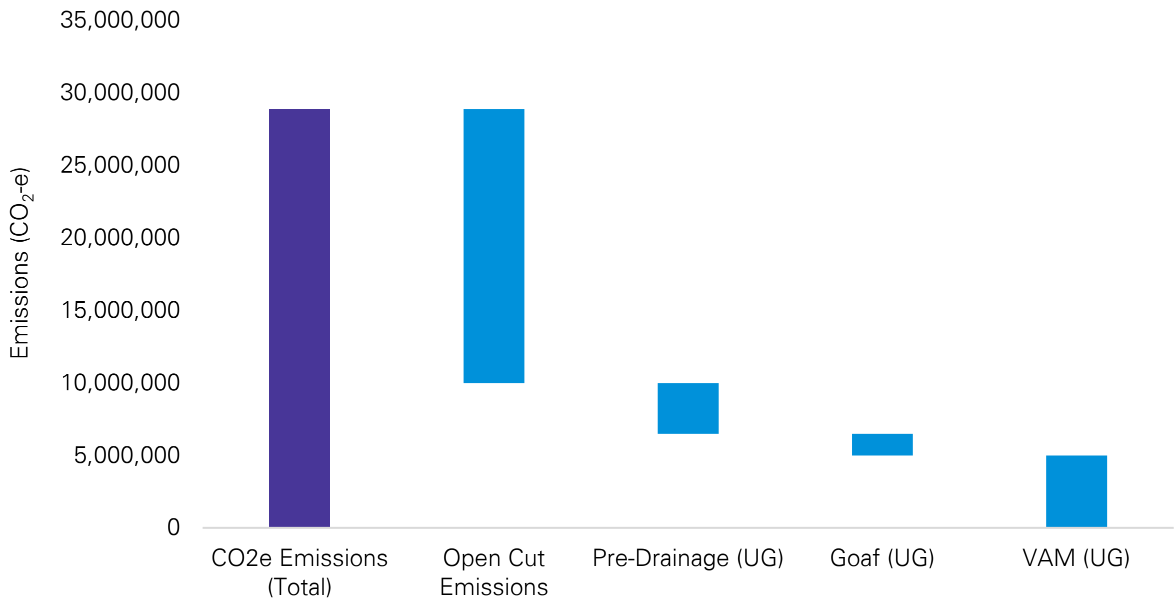


Figure 78 – Total unabated CO_2 emissions from coal mining by source – 2030

(Source: KPMG analysis)

Evident in this figure, the majority of all coal mining GHG emissions are from open cut mine fugitive emissions, of which only pre-drainage gas can be captured. Operational emissions cannot be captured as they are generally emitted during recovery of the coal as over-burden is removed and pressures on the coals reduced. Underground mines still account for around 30% of emissions and hence are worth mitigating if possible.

8.4 CMM capture

8.4.1 Current capture initiatives in the Basin

One major Bowen Basin mine currently produces approximately 40 TJ/d of CMM. An approximate breakdown of the daily coal mine gas production is as follows:

- 9 TJ/d is VAM, which is vented directly to atmosphere and cannot be flared due to low methane concentration (typically less than 0.5%);
- 18 TJ/d is transferred to Arrow (if pipeline specification gas) or to EDL for local power generation;
- 2.5-3 TJ/d of very low concentration gas is vented in the field, for safety and operability reasons; and
- The remaining 10 TJ/d of gas is flared. As methane (CH_4) has a GWP_{100} of 28, flaring is preferable to venting to reduce the overall greenhouse effect of this gas.

There are a number of barriers to utilising coal mine gas, meaning other coal mines have not been as successful, with another major mine operator in the Basin providing the following typical usage of coal mine gas:

- 60-70% is VAM, vented directly to atmosphere; and
- Remainder is flare or vented, although the amount flared instead of vented has increased in recent years which has reduced GHG impact. Some of this gas is a mix of various products other than methane which must be separated before use.

Industry's main challenge to utilising coal mine gas in its current operations is that the quality and production rates of coal mine gas are variable, meaning it is not economic to enter into commercial gas supply agreements. However, the gas could be used more effectively on site, such as using pre-drainage gas to displace diesel usage, which contributes to environmental targets and social licence to operate.

8.4.2 Modelling potential capture improvements

Potential methane capture has been modelled based on a number of inputs and assumptions:

- It was assumed that fugitive emissions from open cut mines were unable to be captured.
- It was also assumed that VAM did not contribute to methane capture.
- The potential recovery rates of CMM through known capture technologies was estimated as a percentage of total CMM by each different source including:
    - Open cut mines:
        - Pre-drainage (30% of pre-drainage gas emissions)
    - Underground mines:
        - Pre-drainage (30% of pre-drainage gas emissions);
        - Goaf (20% of Goaf Gas emissions); and
        - VAM (0% of VAM emissions).

8.4.3 Potential CMM capture pathways

Strategies for improved future utilisation, and therefore enablement of production and beneficiation of CMM, are likely to be crafted around the following key focus areas:

Overlapping tenements: New frameworks for coal and CSG overlapping tenures must continue to strive for maximum flexibility for resource authority holders, inclusive of the ability for relevant parties to mutually agree on non-regulated arrangements that may fall outside legislative or default requirements. Mining and gas operators should also consider smart transfer arrangements that allow gas operators or power producers to maximise revenue through peaking distribution.

Subsidisation: Power station and/or other gas beneficiation facilities will have a greater chance of development through participation in emissions subsidy schemes. Such financial incentives also ease the development of commercial agreements between mining and petroleum lease holders. Australian Carbon Credit Units (ACCUs) held by owners of mine gas beneficiation plants can also be used as offsetting mechanisms for coal mining operations. Additionally, preferential pricing schemes for electricity derived from coal mine gas may incentivise independent power producers or encourage owner/operators to beneficiate gas in other ways.

Transmission Networks: Electrical transmission networks may constrain the output of future power station developments. The capacity of line systems will require upgrading in certain areas to maximise the dispatchable power from mine gas power plants. Upgraded transmission system may then encourage or enable larger power plants and drive common use infrastructure (e.g. gathering and transmission pipelines to centralised power plants).

Ventilation air methane: Mines could be incentivised to reduce VAM from established baseline emissions. Flaring or thermal oxidation of VAM is preferred to simple VAM venting, as combustion of VAM would materially reduce total CO2 equivalent emissions (noting that methane has a CO2-e of 25[13]). The capital expenditure required safe thermal oxidation of VAM, where technology exists although has not yet been adopted for widespread use, means that more incentives via policies, grants, or emissions targets, may be required for coal mining operators to continue developing and increase their usage of this technology.

New Markets: New energy supply chains could be considered utilising either CSG and low-quality gas associated with its production or incidental mine gas that has been treated to suitable quality, although not necessarily pipeline specification gas. Natural gas value chains, starting with either piped gas or gas delivered via virtual pipelines could also open new markets for sales gas from the perspective of resource authority holders. However, given the relative higher cost of gas drainage compared to prevailing natural gas prices, such energy supply chains would likely require emissions' subsidy mechanisms or similar incentives to drive development of these projects.

Infrastructure: Access to pipelines. One of the most significant barriers to utilising pre-drainage coal mine gas is access to export pipelines, due to the typical lack of proximal export pipelines, and the lack of required gas infrastructure to meet pipeline quality and pressure requirements. For these reasons, it is typically not economic to capture coal mine gas and export to the commercial market.

However, pipeline transport is not the only method of gas transport and delivery to end users or customers. Depending on scale of gas delivery and transport distance, there may be economic benefit in considering either compressed natural gas (i.e. trucked transport) or even small scale LNG plants.

[13] 1IPCC (2007) Climate Change 2007: The Physical Science Basis. Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change. [S. Solomon, D. Qin, M. Manning, Z. Chen, M. Marquis, K.B. Averyt, M. Tignor and H.L. Miller (eds.)]. Cambridge University Press. Cambridge, United Kingdom 996 pp.

Gas Quality Requirements: CMM is typically highly variable in quality and flow, hence it can be a challenge to deliver consistently economic gas to market at suitable quality.

Emerging Technology: Developing and incorporating the use of emerging technology, such as membrane separation of methane to improve concentration to useable levels, has the potential to change the dynamics of CMM utilisation in the Basin.

8.4.4 Treatment of CMM for utilisation

Given the varying quality of CMM, including methane content, oxygen content, nitrogen content, dust, fines and water content, significant treatment is required to bring the CMM to a useable specification. For details of the treatment processes required, please refer to Appendix D.

At a high level, CMM may require:

- Dehydration;
- Acid gas removal;
- Nitrogen removal; and
- Oxygen removal.

8.4.5 Potential utilisation options

Power Generation

Historically, the majority of the power generation requirements at centralised hubs and processing facilities have been met by the use of sales gas with gas turbine infrastructure, while the majority of remote compression motive power has been met with (direct) gas drives, the bulk of which are reciprocating engines. However, the electrification of field and hub infrastructure is becoming more common due to the following:

- The use of electric drives can reduce the cost of maintenance of field assets and improves the reliability of the units;
- Electrification creates the opportunity for renewables integration into the power system to assist reducing fuel gas requirements and the carbon footprint of the operation;
- If provided from a centralised power supply, waste heat can be used to generate steam required for processing facilities, which can create boiler fuel gas savings and result in a significant carbon footprint reduction; and
- If provided from a centralised power supply or large microgrids, electrification of remote field stations can provide more flexibility to maintain the gas fired power at high efficiency compared with many individual gas drives at remote locations that can become oversized and less efficient as local field volumes decline.

Therefore, for the gas processing facilities and associated utilities and support facilities, it is expected the electrical power supply would be provided by the local distribution network in the Bowen Basin. This aligns with the recent trend of electrifying gas processing facilities, such as Senex/Jemena's Project Atlas, rather than using dedicated local power generation as has been the traditional approach. The close proximity of gas resources in the Bowen Basin to existing power infrastructure supports this approach. There is still also an opportunity to utilise coal mine goaf gas for local power generation, which can then be used directly by both the coal mines and gas processing facilities, displacing coal fired power generation.

With the rapid development of industrial scale photovoltaic systems, there is also potential to power the gas process facilities with a hybrid gas–powered generation and photovoltaic generation. Such a facility could also be provided by a third-party owner, with potential for a regional grid connection to multiple gas processing facilities. This power supply to gas processing facilities needs to provide very high reliability. The total potential electrical load could range from modest, in the order of hundreds of kilowatts, to large, in the order 50 to 100 megawatts. This depends on the number and size of gas process facilities, and the level of electrification used in the facilities. For reference, the EDL operated waste gas power stations at Moranbah North and German Creek have capacities of 64 MW and 45 MW respectively.

The selection of power generation technology is dependent on a number of factors including scale of application, load variability, proximity to grid networks, topography, pole and line distribution costs. Ultimately the determination of lifecycle cost of electricity can only be evaluated on a case-by-case basis. For all electrification options, the potential benefit of a battery energy storage system (BESS) and renewable generation from wind and solar in combination with more traditional infrastructure, should also be evaluated. The use of microturbines or gas engines for combined heat and power (CHP) applications at remote locations is also a worthwhile valuation.

Compressed Natural Gas

A Compressed Natural Gas (CNG) unit primarily comprises the compressor, compressor auxiliaries, and any associated gas pre-treatment equipment. For the transport of CNG in a virtual pipeline, specialized tube trailers are used that store gas at 250 – 300 barg. The tube trailers and storage tubes are usually supplied, with varying numbers of tubes and trailer capacity, and hooked up to a regular prime mover for transport. CNG packages that are used for refuelling stations are practically identical in nature, with the exception that dispensing and vehicle loading infrastructure is not required.

CNG packages would typically be skid mounted. The compressors themselves could be engine or motor driven, depending on site location (remote or centralised). Ideally, CNG packages should receive gas at above atmospheric pressure, but certain units can tolerate low inlet pressures (<50 kPa). It is not uncommon however to utilise a booster configuration for medium to large size packages.

CNG is worthy of consideration for remote or stranded, small scale assets, particularly where clean gas is available but insufficient quantities to warrant larger scale investment (e.g. pipelines). CNG can be used to transport gas over short distances and can typically provide some cost benefit over larger infrastructure investments where road transport distances are <100km. The variable OPEX does become a key parameter though as road transport maintenance, fuel, labour all contributes significantly to the lifecycle cost for this option.

Micro LNG

The global commoditisation of LNG has provided a solid base for the emergence of new LNG applications and markets, particularly for small scale plants that can be used to monetize captured, smaller resources or otherwise stranded gas that cannot support or justify large scale LNG plant development. Like CNG packaged plants, the use of LNG small scale plants for end users is contingent upon a sustainable, virtual pipeline that can reliably maintain a constant supply of LNG through trucked transport.

Despite higher unit costs associated with the smaller scale plants, the lower capital and general project risk is an enabler for small scale project development and may be attractive to some project developers. As with most technologies in early development, increased maturation and adoption is likely to lead to improved economies of scale. An example of this is the creative solutions being employed to improve modularisation and containerisation of small-scale LNG plants. This includes the use of pressurised LNG tanks for storing smaller amounts of LNG, compared to the conventional atmospheric flat bottom tanks. Pressurized tanks also allow for a more effective way to manage boil-off gas (BOG), largely eliminating the need for costly BOG recovery systems.

Small scale LNG plants are regularly defined as anything below 1 million ton per annum (150 TJ/d) compared with modern large-scale LNG plants that are between 4 – 8 Mtpa per LNG train. Small scale plants have been further sub-categorised as micro-LNG and mini-LNG at capacities of below 30,000 tpa (4.5 TJ/d) and 300,000 tpa (45 TJ/d) respectively. While the core elements remain the same, different liquefaction processes principally drive variations between vendor options. Liquefaction of natural gas in small scale requires a few pre-treatment steps. These process steps help to avoid operational disturbance of the downstream cryogenic plant section and ensure that the LNG product meets defined quality requirements. Depending on the integration of LNG unit with other collection facilities, and the extent of centralized gas processing, the scope of the small-scale LNG plant would change on a case-by-case basis.

Table 19 – Summary of technology providers – small scale LNG

(Source: GHD analysis).

<table>
<tr><th>Technology</th><th>Refrigerant</th><th>Process (licence)</th><th>Technology Supplier</th></tr>
<tr><td rowspan="10">Mixed Refrigerant Cycles</td><td rowspan="8">SMR</td><td>Prico®</td><td>Black & Veatch</td></tr>
<tr><td>SMR</td><td>Chart Industries</td></tr>
<tr><td>SMR</td><td>Wartilsa</td></tr>
<tr><td>PCMR, SCMR</td><td>GE (Baker Hughes-GE)</td></tr>
<tr><td>K-SMR®</td><td>Kogas</td></tr>
<tr><td>AP-M ®</td><td>Air Products (APCI)</td></tr>
<tr><td>Cryobox®</td><td>Galileo</td></tr>
<tr><td>LiMuM®</td><td>Linde</td></tr>
<tr><td rowspan="2">Pre-cooling + SMR</td><td>PCMR</td><td>Kryopak</td></tr>
<tr><td>OSMR®</td><td>LNG Limited</td></tr>
<tr><td rowspan="5">Expansion / Brayton Cycles</td><td rowspan="3">Single Refrigerant – Expander (SRE)</td><td>N2-Reverse Brayton</td><td>Wartsila</td></tr>
<tr><td>OCX®</td><td>Mustang Technologies</td></tr>
<tr><td>Single / Multiple Expander</td><td>Various</td></tr>
<tr><td rowspan="2">Pre-cooling + SRE</td><td>C3MR®</td><td>Air Products (APCI)</td></tr>
<tr><td>NicheLNG®</td><td>CB&I</td></tr>
</table>

8.5 Infrastructure requirements

There is measurable potential in harnessing methane emissions from coal producing mines in the Bowen Basin and converting them into sales quality gas, also leading to reduced CO_2 emissions from the region. An analysis on methane emissions and consequently potential methane capture from various coal mines currently operating in the Bowen Basin was performed. The analysis covered the majority of the Bowen Basin with approximately 52 mines being considered. As the Bowen Basin comprises both open-cut and underground coal mines, coal mine methane capture assessment was conducted for both types of mines.

8.5.1 Methodology & assumptions

Queensland mine gas does not contain appreciable amounts of acid gas components or higher hydrocarbon gases. The presence of volatile heavy metals (e.g. mercury, selenium etc) is also not typical of mine gas. Therefore, gas treatment is primarily concerned with de-hydration, although inert gas removal could be important to meet industrial gas users' and/or sales gas specifications. The presence of oxygen can require a specific oxygen removal unit since oxygen is known to degrade downstream solvent chemicals and increase the potential for corrosion, especially for steel pipelines. Removal of CO2 from wet gas is also important for managing corrosion in steel pipelines and gas processing equipment, hence the application of acid gas plants upstream of dehydration units. Where only minor amounts of acid gas are present, they can be removed by absorption along with the removal of water.

Fractionation and separation units for C2+ recovery was not considered for mine gas processing.

The development of coal mine methane infrastructure must consider not only the varying feed quality of the CMM itself, but also the end user application. Typical gas specifications for pre-drainage gas and goaf gas are presented in the tables below:

Table 20 – Typical coal mine methane quality
(Source: GHD analysis).

Parameter	U.o.M	Pre-Drainage gas	Goaf Gas
Methane Content	Mol%	85-95	30-60
Carbon dioxide Content	Mol%	3-5	5-12
Oxygen Content	Mol%	1-2	2-10
Total Inert Content	Mol%	5-7	>30
Total sulphur	mg/m3	10-50	10-50
Dust	-	Low	High
LHV (methane)	MJ/m3	39.8	
LHV	MJ/m3	32-38	12-22

Table 21 – Typical end user feed specification

(Source: GHD analysis).

Parameter	U.o.M	Power Generation Note 1	Industrial User Note 2	Sales Gas (AS4564)
Methane Content	Mol%	>30-40	>94	-
Carbon dioxide Content	Mol%	<50	<3.0	-
Oxygen Content	Mol%	< LEL	<0.2	<0.2
Total Inert Content Note 3	Mol%	No Limit	<6-7.0	<7.0
Total H2S	mg/m3	Minimal	<7.0	<5.7
Total Sulphur	mg/m3	Minimal	Minimal	<50
Water Content	mg/m3	No free water	No free water	112.0
Dust	-	Nil	Nil	Nil
LHV	MJ/m3		> 35	~39.8 (Max. 42.3 HHV)

Notes:

1. Generalised specification – requirements will differ depending on application (gas engines vs turbine/micro turbines)
2. Typical user might include reforming plant (H2 production) or fertiliser plant (NH3/Urea production or user requiring general process heat (e.g. for a fired heater)
3. Inert content, methane content and extent of variability will all be key considerations in evaluating choice of power generation technology. Traditionally, gas engines are most flexible and can operate on much lower heating value gas. Efficiency, by products' formation and contaminant emissions (SOx, NOx, PMs) must also be considered on a case-by-case basis.

8.5.2 Results and Observations

Flowrates of methane emissions and potential methane captured from various coal mines in the Bowen Basin were identified. It was inferred that underground mines could both emit and capture higher quantities of methane when compared to open-cut mines. The Bowen Basin was segregated into different geographical regions comprising a specific set of coal mines with their corresponding methane emissions and potential for captured methane flow rates. The total methane emissions and potential CMM capture are tabulated Table 22 and Table 23 respectively.

Based on the tabulated data, a series of options was identified for each mining hub/region. In accordance with the technologies capture pathways identified above, a series of corresponding treatment technologies and, hence, overall infrastructure scope was developed. The facility scoping for each scenario was then used to derive rough order numbers for capital expenditure.

A summary of infrastructure scenarios is presented in Table 24. Under each scenario the suite of likely, suitable process technologies was considered for upgrading of the relevant gas.

Table 22 – Total methane emissions flowrate

(Source: GHD Analysis)

	Open Cut (TJ/d)		Underground (TJ/d)		
Geographical Location	Pre drainage	Fugitive	Pre drainage	Goaf	VAM
Moranbah North	0.74	1.37	0	0	0
Moranbah Central	3.68	6.84	12.67	5.43	18.10
Clermont	0.47	0.88	0	0	0
Middlemount	0.6	1.1	10.7	4.6	15.3

	Open Cut (TJ/d)		Underground (TJ/d)		
Geographical Location	Pre drainage	Fugitive	Pre drainage	Goaf	VAM
Blackwater	1.5	2.8	0	0	0
Rolleston	0.5	1.0	0	0	0
Moura	0.7	1.4	0	0	0

Table 23 – Captured methane flowrate
(Source: GHD Analysis)

Geographical Location	Open Cut (TJ/d)	Underground (TJ/d)	Total (TJ/d)
Moranbah North	0.22	0	0.22
Moranbah Central	1.1	4.9	6
Clermont	0.14	0	0.14
Middlemount	0.2	4.1	4.3
Blackwater	0.4	0	0.4
Rolleston	0.16	0	0.16
Moura	0.2	0	0.2

Based on the values presented in the above table, potential methane capture is the highest for Moranbah Central and Middlemount region. The Moranbah central region comprises of noteworthy mines like Moranbah North Mine, Goonyella Broadmeadow Mine, Grosvenor Mine and the Middlemount region comprises of notable mines like Capcoal Mine, Kestrel Mine, Oaky Creek Coal Complex to name a few. Figure 79 provides a map of the Bowen Basin indicating the total captured methane in the region.

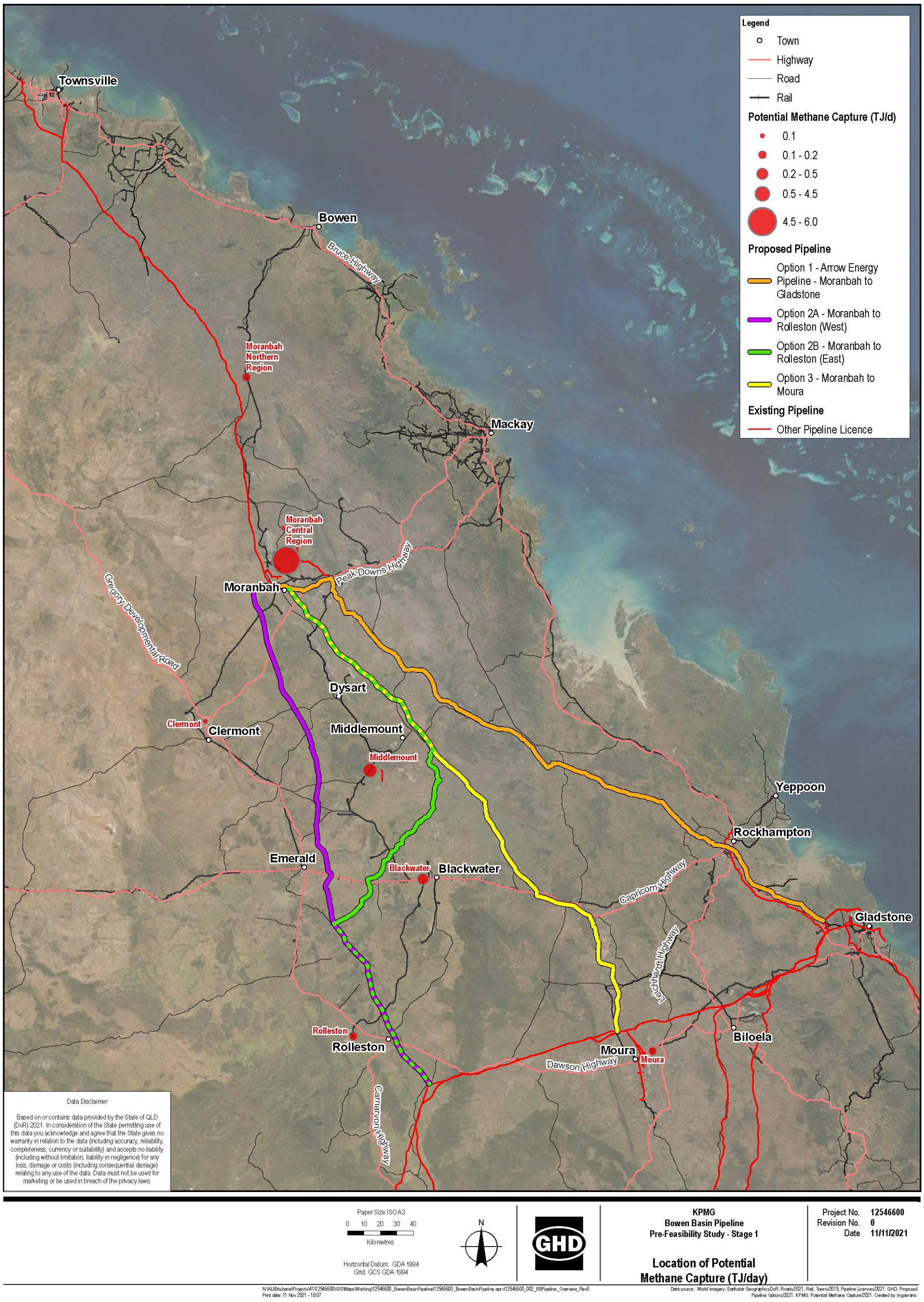


Figure 79 – Potential methane captured

(Source: GHD analysis)

Table 24 – Summary of possible CMM scenarios – end user applications

(Source: GHD analysis)

Region	Type	Gas Drainage (TJ/d)	Gas Drainage (GJ/d)	Scenarios			
				CNG	***Micro LNG***	***Power Gen***	***Pipeline Export***
North Moranbah	Pre-Drainage	0.20	200	Yes	No	Yes	Not feasible
	Goaf	0.0	0	No	No	Yes	Not feasible
Moranbah Central	Pre-Drainage	4.4	4410	No	Yes	Yes	Yes
	Goaf	0.69	689	No	No	Yes	Not feasible
Middlemount	Pre-Drainage	3.00	3038	No	Yes	Yes	Yes
	Goaf	0.58	581	No	No	Yes	Not feasible
Blackwater	Pre-Drainage	0.40	404	Yes	No	Yes	Not feasible
	Goaf	0.00	0	No	No	Yes	Not feasible
Clermont	Pre-Drainage	0.13	128	Yes	No	Yes	Not feasible
	Goaf	0.00	0	No	No	Yes	Not feasible
Rolleston	Pre-Drainage	0.15	148	Yes	No	Yes	Not feasible
	Goaf	0.00	0	No	No	Yes	Not feasible
Moura	Pre-Drainage	0.20	200	Yes	No	Yes	Not feasible
	Goaf	0.00	0	No	No	Yes	Not feasible

Based on the tabulated CMM scenarios, a basic assessment of required infrastructure can be undertaken. For the purposes of this study each end user application was considered to be an offtake for the respective (i.e. 100%) volume of the available mine gas. In reality there may be various configurations at each potential mining hub or region, including the blending of pre-drainage gas and goaf gas from different mines. The relative distance to final customer will also influence the decision in regard to gas transport, which may be as gas, liquid or in a virtual pipeline with road transport.

Pipeline Export

The pipeline export scenario can also be considered a proxy for industrial gas offtake since pipeline specification gas could be expected at the battery limit of an industrial facility. Pipeline export requires the highest quality specification and therefore warrants the below steps:

- TEG Dehydration: The design of TEG unit requires a specific water target. It is typical to design for pipeline specification which requires water levels in the product gas to be no greater than 65mg/Sm3;

- Acid Gas Treatment: A mixed solvent process can be assumed, which may be factored on expected low sulphur content and relative high CO2 content; and
- Compression: A compressor station is required for each pipeline export scenario to take gas from the relative low pressure at the exit of treatment units to pipeline operating pressure of ~9-10 MPag. Owing to relatively close proximity to other transmission systems, it is not envisaged that booster compressor stations would be required.

Upgrading of goaf gas to pipeline specification was not considered a realistic scenario, given both scale and quality concerns, hence the requirement for oxygen and nitrogen rejection units was omitted.

Power Generation

The relatively small scale under consideration is assumed to be gas engines. No additional pre-treatment units are considered in combination with power generation infrastructure. Goaf gas utilisation through power generation is considered the only viable option.

Micro LNG

The LNG plant can be considered a "black box" package, supplied turnkey on an EPC basis. For small scale plants the liquefaction plant cost, being containerised or modularized, is somewhat standardised. Site establishment and bulk earthworks costs are significantly lower for small scale plants, while equipment unit costs are greater.

Compressed Natural Gas (CNG)

Configurations employing CNG assumed to include TEG dehydration and Acid gas treatment, followed by packaged compression units that also encompass loading and filling infrastructure for road transport loading. It should be noted that the greatest cost variation for any scenario employing CNG relates to logistics (number of trucks, virtual pipeline distance, truck cycle time, the allowable shift times and buffer storage at delivery location(s)).

8.5.3 Economic Parameters

Assumptions for the rough order outline of total installed costs are outlined below:

Pipeline Export

- Costs for TEG dehydration and, AGR units, i.e. gas processing are included. As with conventional CSG export infrastructure, the technology does not vary significantly.
- Cost rates for gas processing facilities, excl. compression stations, was considered as $3 million per TJ/day capacity, inclusive of owners' costs.
- Pipeline costs can be taken on a per inch per kilometre basis, which was estimated at $70000/in/km. Trunk lines were assumed to be 6 inch.
- Compression cost were considered as for high pressure, screw units for trunk systems that may transport gas to a main transmission pipeline. Costs have been determined on a duty basis, assuming two stage compression with pressure ratio of 10.
- Trunk lines from CMM generators to e.g. a mains transmission was assumed to be not greater than 20km.

Power Generation

Installed costs for power equipment were based on specific project experience with larger commercial installations ($1250-1500 / kWe for >5MWe units). A figure of 1750- $/kWe considers turnkey plant supply but only for the gas engine, genset and controls and other auxiliaries. It does not consider e.g. combined heat and power integration. A gas engine efficiency of 42% was assumed based on the calculated thermal loads.

Micro LNG

Installed cost inclusive of pre-treatment and regasification was assumed as ~$2200 AUD/tonne LNG, excluding site storage units. Site storage is accomplished with bulk, vacuum insulated (VI) tanks that store cryogenic LPG under pressure (up to 9 barg).

Compressed Natural Gas

Package costs were estimated from a recent feasibility study for a mobile refilling station, processing 1-2 TJ/day. This package size was considered suitable for scaling purposes TEG and AGR unit treatment costs were applied as for pipeline export scenarios. Data for logistics was aggregated based on the following:

- Trailer Capacity – Single and articulated trailers are equipped with between 26500 – 65000 L water capacity, which is equivalent to 180 – 400 GJ. The larger, articulated units (400GJ) were used as a basis, with an estimated cost of ~AUD$750 000 each.
- Buffer Capacity – Buffer capacity was not considered for any virtual pipeline system.

OPEX

The elements of OPEX are highly variable across different technology platforms and potential future configurations for CMM capture. Quantitative estimates have not been made for chemical inventories, fuel, major equipment replacements, logistical costs, labour and maintenance. Instead, project data was examined to derive a generalised processing cost of 1$/GJ.

Summary

A summary of the various end user scenarios and related CAPEX/OPEX requirements are presented in Table 25. Note that lifecycle costs will have a material influence on the viability of different hub configurations and further analysis is required to select optimum end user application.

In order to provide incremental costs for the extraction of mine gas, for comparison to forecasted gas prices, which are on a unit basis (i.e. $/GJ or $/MMBTU), the equivalent annual cost (EAC) was calculated for each configuration. EAC was presented in $/GJ.

$$EAC\left[\frac{\$}{unit}\right] = \left[\frac{\frac{Asset\ Cost\,x\ Discount\ Rate}{1-(1+Discount\ Rate)^{-n}} + Operating\ Cost\left[\frac{\$}{yr}\right]}{Asset\ Capacity\ \left[\frac{units}{yr}\right]}\right]$$

Table 25 – End user applications and CAPEX requirements

(Source: GHD Analysis)

Region	Type	Potential Methane Capture (TJ/d)	CNG				Micro LNG				Power Gen				Pipeline export			
			Feas.	CAPEX (M$)	OPEX (M$/yr)	EAC ($/GJ)	Feas.	CAPEX (M$)	OPEX (M$/yr)	EAC ($/GJ)	Feas.	CAPEX (M$)	OPEX (M$/yr)	EAC ($/GJ)	Feas.	CAPEX (M$)	OPEX (M$/yr)	EAC ($/GJ)
North Moranbah	Pre-Drainage	0.2	Yes	2.5	0.1	4.7	No	-	-	-	Yes	1.5	0.1	3.14	N/A	-	-	-
	Goaf	0	No	-	-	-	No	-	-	-	N/A	-	-	-	N/A	-	-	-
Moranbah Central	Pre-Drainage	4.41	No	-	-	-	Yes	83	1.5	6.53	Yes	32.2	1.5	3.14	Yes	27.5	1.5	2.83
	Goaf	0.689	No	-	-	-	No	-	-	-	Yes	5	0.2	3.14	N/A	-	-	-
Middlemount	Pre-Drainage	3.038	No	-	-	-	Yes	57.2	1.1	6.53	Yes	22.1	1.1	3.14	Yes	22.1	1.1	3.13
	Goaf	0.581	No	-	-	-	No	-	-	-	Yes	4.2	0.2	3.14	N/A	-	-	-
Blackwater	Pre-Drainage	0.404	Yes	4.3	0.1	4.13	No	-	-	-	Yes	2.9	0.1	3.14	N/A	-	-	-
	Goaf	0	No	-	-	-	No	-	-	-	N/A	-	-	-	N/A	-	-	-
Clermont	Pre-Drainage	0.128	Yes	2.1	0	5.93	No	-	-	-	Yes	0.9	0	3.14	N/A	-	-	-
	Goaf	0	No	-	-	-	No	-	-	-	N/A	-	-	-	N/A	-	-	-
Rolleston	Pre-Drainage	0.148	Yes	2.2	0.1	5.48	No	-	-	-	Yes	1.1	0.1	3.14	N/A	-	-	-
	Goaf	0	No	-	-	-	No	-	-	-	N/A	-	-	-	N/A	-	-	-
Moura	Pre-Drainage	0.2	Yes	2.5	0.1	4.7	No	-	-	-	Yes	1.5	0.1	3.14	N/A	-	-	-
	Goaf	0	No	-			No			N/A	-	-	-	N/A	-	-	-	-

8.6 Challenges

The Bowen Basin, which has traditionally focused on coal production, has the potential to bring more gas to Queensland's domestic and export markets – by opening up areas for new CSG gas production and capturing unutilised gas from underground mines. However, the marked difference in CSG gas and incidental mine gas quality is a potential barrier to effectively scaling common use infrastructure.

Traditionally, mine operators have also been averse to either investing in new gas processing infrastructure or owning and operating that infrastructure. Generally, mine operators are supportive of power generation and moving surplus energy as "electrons" as opposed to "molecules". The current business landscape therefore suggests that policy drivers, improvements to the regulatory frameworks and cross sector collaboration from both private and public sector players will be critical to the development of the Bowen Basin gas resources.

There are numerous challenges in increasing the beneficial use coal mine methane emissions, several of which have been identified in the preceding sections. The history of coal seam gas development in Queensland had created some challenges in conflicting goals between coal mine operators and coal seam gas companies. Whilst there had been changes in Government legislation and working practices between the different industries, there remains a number of challenges that will need to be addressed in order to achieve a material increase in the beneficial use of coal mine methane emissions.

Key challenges identified during the study include the following:

- Limited active coal seam gas production in close proximity to existing mines – the extent of active coal seam gas production covers a small area of the extent of mines in the basin, therefore there is currently limited ability for mines to access coal seam gas production to take away coal mine gas.
- Mines between Moranbah and Blackwater do not have access to a gas pipeline – this would then require other methods to capture coal mine gas for beneficial use, which typically involves the use of complex specialist gas processing equipment.
- Variability of gas from a coal seam gas producers perspective – pre-drainage coal mine gas is generally considered to be a variable source of gas, not something that would underpin a development and used as a top up gas source.
- Cost of alternate uses – a common theme from consultation with the mining companies was that beneficial use of coal mine gas was generally not economical if not in close proximity to a gas processing facility.
- Power generation as a market source for coal mine gas is becoming more challenging due to increasing penetration of renewables – this has shifted the operating profile of the power generation facilities in the basin that currently use coal mine gas. This is resulting in more intermittent demand for power generation and given the need to continuously drain the goaf is resulting in the gas to be flared when the power generation isn't running.
- The absence of strong Government requirements to ensure beneficial use of coal mine gas – currently mine operators are not forced to productively use coal mine gas making it easy to default to the simplest solution to ensure mine safety, which is flaring or venting.
- Overlapping tenure – described in detail below.

One of the most significant barriers to utilising coal mine gas is **access to export pipelines**, due to the typical lack of proximal export pipelines, and the lack of required gas infrastructure to meet pipeline quality and pressure requirements. For these reasons, it is typically not economic to capture coal mine gas and export to the commercial market.

However, pipeline transport is not the only method of gas transport and delivery to end users or customers. Depending on scale of gas delivery and transport distance, there may be economic benefit in considering either compressed natural gas (i.e. trucked transport) or even small scale liquefied natural gas (LNG) plants.

8.6.1 Overlapping tenure and coexistence

Almost 90% of Queensland's coal tenure and coal seam gas tenure is overlapped, which in the past has tended to lead to an adversarial outcome. Overlapping tenure is particularly evident in the Basin near Moranbah where there's a concentration of overlapping granted Mining Leases (ML) and Petroleum Leases (PL) (Figure 80).

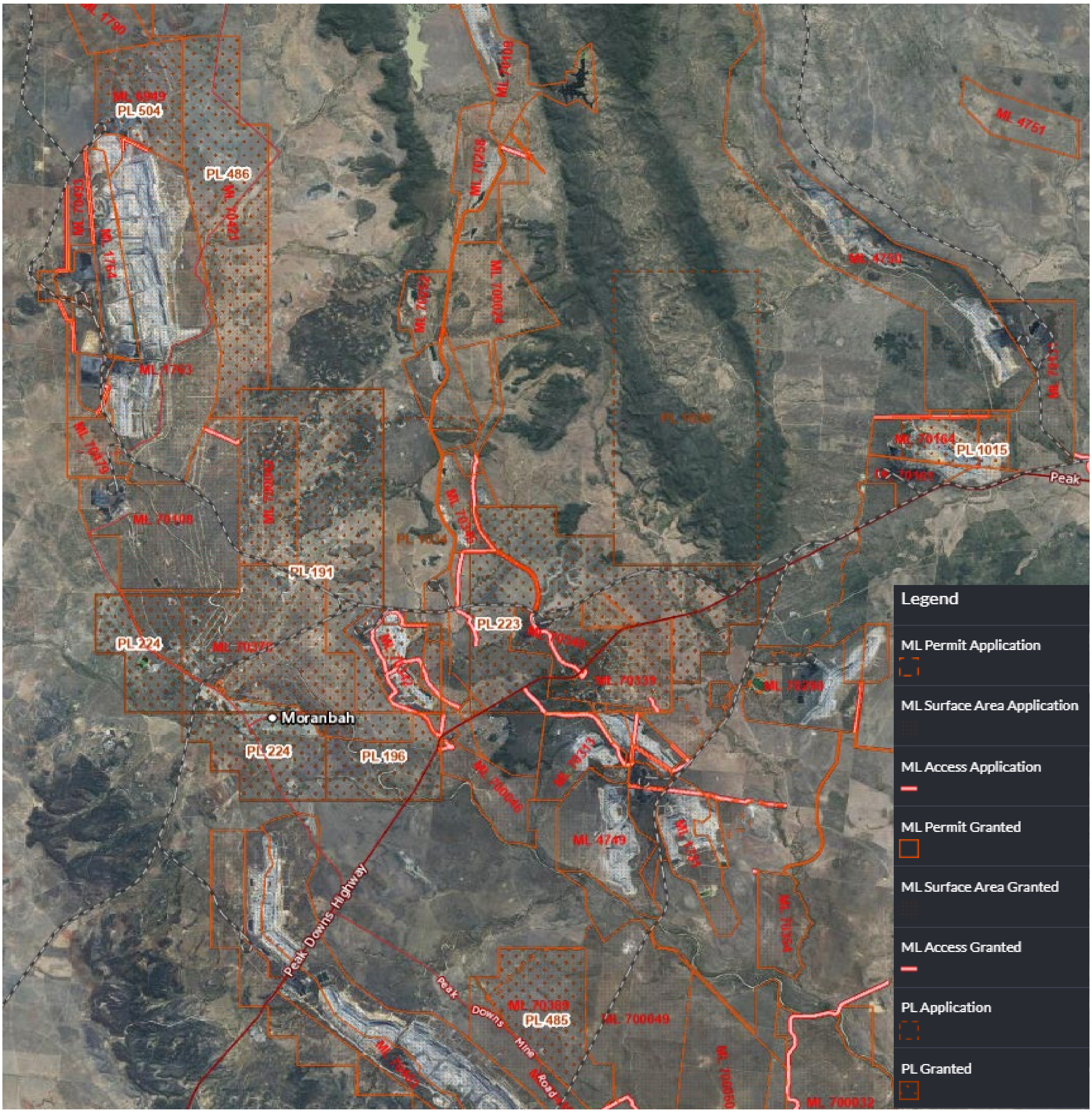


Figure 80 – Overlapping ML and PL holders in the Bowen Basin

(Source: GHD Analysis)

A revised framework for addressing overlapping tenure was incorporated into the *Mineral and Energy Resources (Common Provisions) Act 2014 (MERCPA)*. The 'new' overlapping tenure framework is a legislated default regime which applies where overlapping parties cannot otherwise agree.

A simultaneous operations zone is an area where coal and CSG production activities can co-exist. A key feature of the revised overlapping tenure framework is the requirement for a joint interaction management plan (JIMP) in various overlapping operating scenarios. A JIMP Industry Guide OLT-Industry-Guide-final-Dec16-2.pdf (qrc.org.au) has been prepared by the Queensland Resources Council (QRC) to assist coal and CSG businesses to meet the 'new' requirements.

In relation to the JIMP requirements under the respective safety legislation, the party responsible under that legislation to make a JIMP must make reasonable attempts to consult with the other party. The party responsible to make a JIMP must have regard to any reasonable provisions proposed by the other party(s) relating to the management of risks and hazards and either reach agreement about the content of the proposed JIMP or apply for arbitration.

The 'new' overlapping tenures legislative framework for coal and CSG tenure is governed by MERCPA. Other legislation which applies to coal and CSG tenures includes the:

- *Mineral and Energy Resources (Common Provisions) Regulation 2016;*
- *Mineral Resources Act 1989 (MR Act);*
- *Mineral Resources Regulation 2013;*
- *Coal Mine Safety and Health Act 1999;*
- *Coal Mine Safety and Health Regulation 2001;*
- *Petroleum and Gas (Production and Safety) Act 2004 (P&G Act);*
- *Petroleum and Gas (Production and Safety) Regulation 2004; and*
- *Petroleum Act 1923.*

The overlapping tenure framework in Chapter 4 of MERCPA replaces the old framework in Chapter 8 of the MR Act and Chapter 3 of the P&G Act. Chapter 7, Part 4 of MERCPA provides transitional provisions applying to granted tenure (and some tenure applications) and existing agreements relating to the matters the subject to MERCPA at commencement (see Section 5). The 'new' framework generally applies to all forms of coal mining tenure and CSG tenure, with the exception of petroleum tenure under the Petroleum Act 1923.

From 27 September 2016, the new framework applies to holders of the following resource authorities where there is an overlapping area:

- Exploration permit for coal (EPC);
- Mineral development licence for coal (MDL (coal));
- Mining Lease (ML) for coal;
- Authority to prospect (ATP) for CSG; and
- Petroleum Licence (PL) for CSG.

The framework seeks to optimise the safe development of Queensland's coal and CSG resources by:

- simplifying the pathway to and improving the certainty of the grant of overlapping tenure;
- incentivising negotiated arrangements for collaborative and cooperative concurrent production of both resources in overlapping areas;

- providing a default set of arrangements and dispute resolution processes to provide certainty to arrangements for coordination of activities if the parties cannot agree between themselves;
- providing a structure for joint coordination and management of health and safety; and
- reducing administrative burdens, while preserving production rights already granted.

Chapter 4 of MERCPA details provisions for overlapping coal and petroleum resource authorities with Section 102 outlining the main purposes as:

- facilitate the co-existence of the State's coal and coal seam gas industries;
- ensure that participants in each of the industries co-operate to optimise the development and use of the State's coal and coal seam gas resources to maximise the benefit for all Queenslanders; and
- establish a statutory framework that applies if the participants do not otherwise agree.

The main purposes are achieved by:

- removing barriers to the grant of resource authorities for coal and coal seam gas production;
- allowing a right of way for coal production subject to notice and compensation requirements;
- imposing ongoing obligations on participants in each of the industries to exchange relevant information; and
- providing for participants in each of the industries to negotiate arrangements as an alternative to particular legislative requirements.
- As a minimum, overlapping resource authority holders under the framework will need to comply with the mandatory requirements set out under section 117 of MERCPA. Detailed requirements for ML and PL holders are outlined below.

For ML (coal) holders:

- giving an advance notice to an overlapping ATP or PL holder within 10 business days of making a ML (coal) application (section 121);
- if overlapping an ATP holder and exceptional circumstances (i.e. extension of the notice period to achieve full economic potential of CSG production) is established – a notice to the department about the exceptional circumstances (section 127(8)(b));
- if overlapping a PL – have an agreed joint development plan in place within the statutory timeframes and notifying the department of the plan (section 130);
- ensure an agreed joint development plan with a PL holder is consistent with any initial development plan or later development plan under the MRA (section 132);
- notify the department of any changes to an agreed joint development plan that result in cessation, or significant increase or reduction, of activities by the ML (coal) holder or PL holder (section 133);
- exchange required information with the overlapping ATP or PL holder (section 154); and
- comply with Ministerial directions about agreed joint development plans and requests for information (sections 157-160).

For PL holders:

- giving a petroleum production notice to the holder of an overlapping EPC, MDL (coal), or ML (coal) within 10 business days of making a PL application (section 141);

- if overlapping a ML (coal) – have an agreed joint development plan in place within the statutory timeframes and notifying the department of the plan (section 142);
- ensure an agreed joint development plan with a ML (coal) holder is consistent with any initial development plan or later development plan under the P&G Act (section 145);
- notify the department of any changes to an agreed joint development plan that result in cessation, or significant increase or reduction, of activities by the PL holder or ML (coal) holder (section 146);
- exchange required information with the EPC, MDL (coal) or ML (coal) holder (section 154); and
- comply with Ministerial directions about agreed joint development plans and requests for information (sections 157-160).

In an overlapping area that is subject to a ML, a gas party which holds petroleum exploration tenure or a PL has a right to be offered, on reasonable terms, any incidental coal seam gas (ICSG). ICSG is defined under the Mineral Resources Act 1989 as coal seam gas that is mined, or proposed to be mined by the mining lease holder under the following circumstances (Section 318CM):

- the mining happens as a necessary result of coal or oil shale mining carried out under the mining lease;
- the mining is necessary to ensure a safe mine working environment for coal or oil shale mining under the mining lease; or
- the mining is necessary to minimise the fugitive emissions of methane during the course of coal mining operations.

Holders of overlapping resource authorities are encouraged to seek legal advice on the impacts of the MERCPA framework and provisions for ICSG under the MR Act 1998 on their resource projects.

8.7 New fugitive emissions - Basin development

Whilst the capture of CMM as part of the development of the Bowen Basin will assist in reducing Queensland's fugitive emissions, the development of new CSG production in the Basin will add additional fugitive emissions from these development activities. As such, a model has been constructed to determine the likely volumes of additional new emissions from Basin development.

The development emissions were estimated using the emissions guidelines contained within the most recent NGER report. The estimation of the development emissions provides an outline of the volume of emissions incurred as fugitive emissions from CSG operations.

The fugitive emissions were modelled using a low, mid and high case scenario to give a three banded estimate for the low mid and high production emissions cases. The three bands represent the uncertainty inherent in the production volumes as well as produced water variation and transport emissions uncertainty.

8.7.1 Methodology

Fugitive emissions were modelled for all four production scenarios (refer Section 7.4 for scenario details).

Construction emissions

Construction emissions were calculated by approximating a weighted average for the expected emissions in CO2-et per dollar of CAPEX by combining the average emissions per dollar GDP for Australia, for the construction industry specifically, and the oil and gas industry. The value obtained was then used to estimate the construction emissions for the development of the Bowen basin at an initial CAPEX of AUD $4 bn to give approximately 1.3 million tonnes of CO2 equivalence. These calculations are outlined in detail in the emissions model.

Operations emissions

Modelling fugitive greenhouse gas emissions from the development of the basin was achieved by using the estimate calculations outlined in the current National Greenhouse and Energy Reporting (NGERs) report. Fugitive emissions were approximated by the calculation and summation of the expected emissions from production, processing, transport, produced water, flaring, and venting for a variety of different production scenarios. It was assumed by the model that storage emissions would be negligible as no storage expansion to accommodate Bowen basin gas is anticipated.

The calculation of operating emissions was carried out using the below equations and inputs:

Production Emissions = $$E_{ij} = \sum_{k} Q_{ik} \times EF_{ijk} \times S_{ij} \div SD_{ij}$$

Processing Emissions = $$E_{ij} = \sum_{js} (Q_{is} \times EF_{ijs}) \times S_{ij} \div SD_{ij}$$

Transport Emissions = $$E_{ij} = (L_i \times EF_{ij})$$

Produced Water Emissions = $$E_{ij} = W_i \times EF_{ijw} \times S_{ij} / SD_{ij}$$

Flaring Emissions = $$E_{ij} = Q_i \times EF_{ij}$$

Venting Emissions = $$E_{ij} = Q_i \text{ x } 0.0198 \text{ x } 22.5$$

Where:

Eij = The total emissions for the specified emissions source in tonnes of CO2 equivalence

EFij(w,k,s) = The emissions factor relevant to the emissions source as specified in NGER datasheets

Qi = The volume of gas produced in tonnes

Wi = the volume of water in megalitres

Sij/SDij = a constant relating the proportion of methane in produced gas and the default share of emissions derived from NGER datasheets.

8.7.2 Results

The total emissions are below 10Mt CO2-et over the life of the project.

Using this estimate, we can see that the 12 Mt total emissions from the basin development (high case in central scenario) would require only a 4% reduction in overall underground coal mine fugitive emissions to achieve emissions ROI (4% of mid case >300Mt unabated underground coal mine emissions).

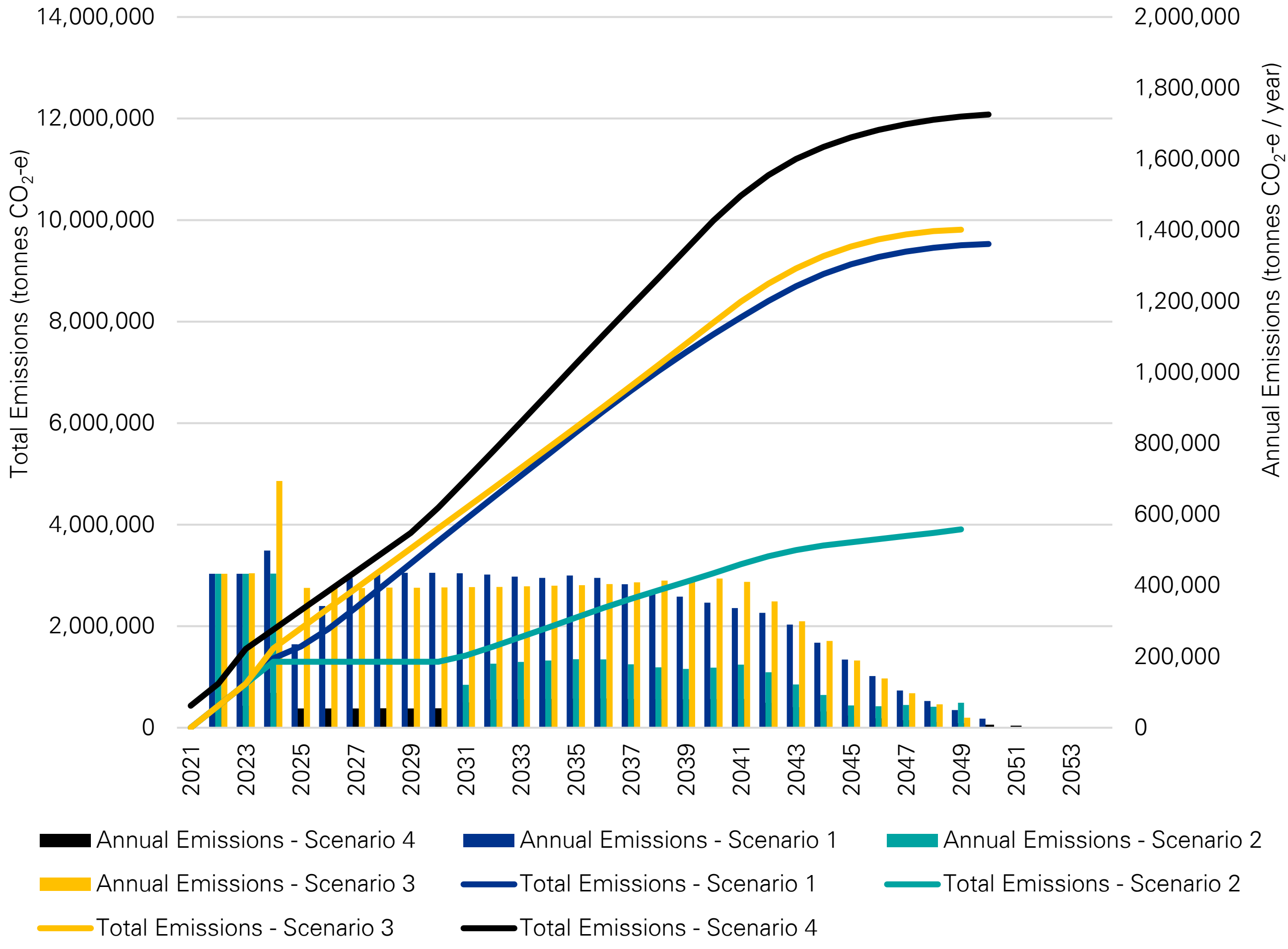


Figure 81 – Basin development emissions by scenario

(Source: KPMG analysis)

As has been demonstrated by the fugitive emission modelling, the reduction in fugitive emissions from utilising CMM capture, even if only a small portion of the total, will far outweigh the GHG emissions impact of developing the Basin as a CSG play. This is largely due to methane having a GWP_{100} of 28 and hence capturing and combusting it will have a net positive effect on the emissions of the project despite the emissions required to develop the Basin.

9. Infrastructure options

9.1 Approach

As detailed in Section 7, there are a number of pathways to economically produce natural gas from multiple regions in the Basin that would ultimately underpin the construction of a gas pipeline connection to the ECGM.

Whilst a new gas pipeline isn't the largest component of costs to develop the Bowen Basin, stakeholder reflections suggest that lack of infrastructure has been a key contributing factor to the delayed development of the Basin and will remain a key barrier into the future. Without the construction of a connecting pipeline to the ECGM, the Blackwater and Moranbah areas of the Basin are not likely to encourage investment and will not result in any material gas development occurring.

In order to facilitate the production scenarios described in Section 7.0, pipeline infrastructure options and industry requirements have been identified. The gas infrastructure options considered included gas processing facilities and export pipeline routes to connect the gas production in the Basin to the ECGM and beyond.

The key consideration was for sizing for gas process facilities and gas pipelines, and potential routes for connection to the ECGM. Location of gas processing facilities will be proximate to the gas source in the areas of main development, and in this study are considered nominal in location within sub-areas of the study. As described in Section 7, these sub-areas are Moranbah, Blackwater and Mahalo.

9.2 Industry proposed Bowen Basin pipelines

As part of the development of the Bowen Basin to date, many proponents have identified potential pipeline solutions. The following proposed pipelines vary in project maturity; however, they are at the early stages of development, and have not made material progress in recent years:

Arrow Energy Bowen Pipeline

Figure 82 illustrates the proposed route as part of Arrow's Bowen Pipeline Project. This proposed pipeline connects Arrow's land interests north of Moranbah to an LNG export facility at Gladstone. It proposes diameter of up to DN1050 (42 inch) with capacity to supply approximately 1,500 TJ/d at a maximum operating pressure of 10.2 MPa.

The route was originally developed by Enertrade in 2006 and included the development of an Environmental Impact Statement (EIS) for the "Central Queensland Gas Pipeline". Enertrade was acquired by Arrow Energy/AGL in 2007 along with this pipeline route.

Subsequently, Arrow Energy completed an EIS for the "Arrow Bowen Pipeline Project" in 2012, which was approved by the Queensland Government in March 2013 and the Commonwealth Government in October 2014.

A pipeline licence for the Arrow Bowen Pipeline was granted in 2017 for a term of 50 years, however no construction has commenced, and the project appears to have been put on hold.

Arrow Energy's pipeline is the most progressed of all the proposed pipelines.

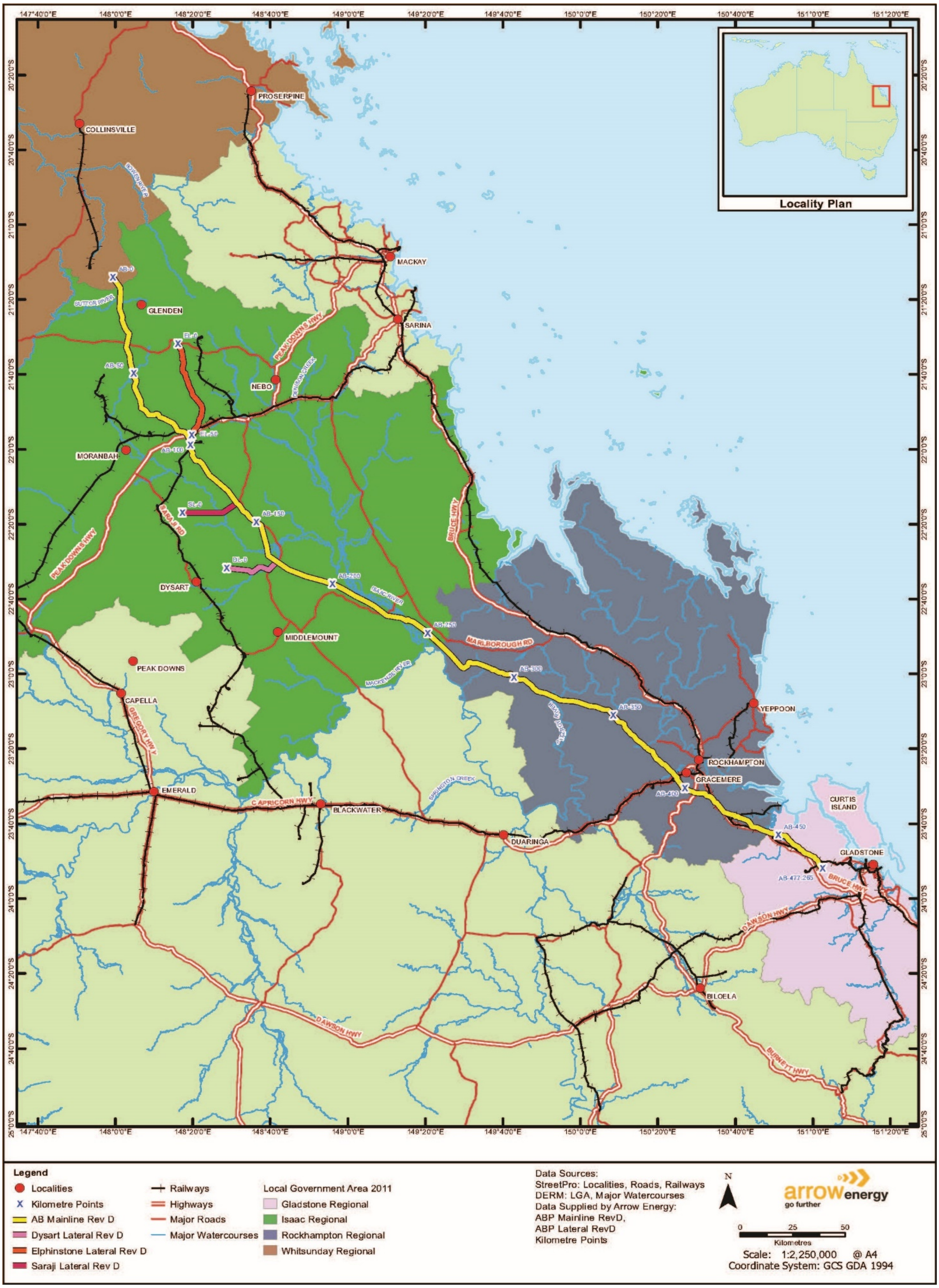


Figure 82 Arrow Bowen Pipeline Preliminary Route

(Source: Arrow Energy (2017). Environmental Impact Statement: Arrow Bowen Pipeline Project (Executive Summary)

APA Group Galilee Pipeline

This proposed pipeline connects gas exploration permits, held by Vintage Energy and Comet Ridge Galilee Pty Ltd, to users in Moranbah. As shown in Figure 83, the pipeline route traverses approximately 240km from the Galilee Basin, west of Clermont, and terminates just east of Moranbah.

A memorandum of understanding (MOU) was signed between APA, Comet Ridge and Vintage in May 2019 outlining the concept of the project. In August 2019, APA were granted a pipeline survey license by the Queensland Government. APA continues to investigate potential capacities and market scenarios for the pipeline, as such, the pipeline has not been sized, and its proposed capacity is unknown. Further development of this project requires a financial commitment by Comet Ridge and Vintage Energy Ltd.

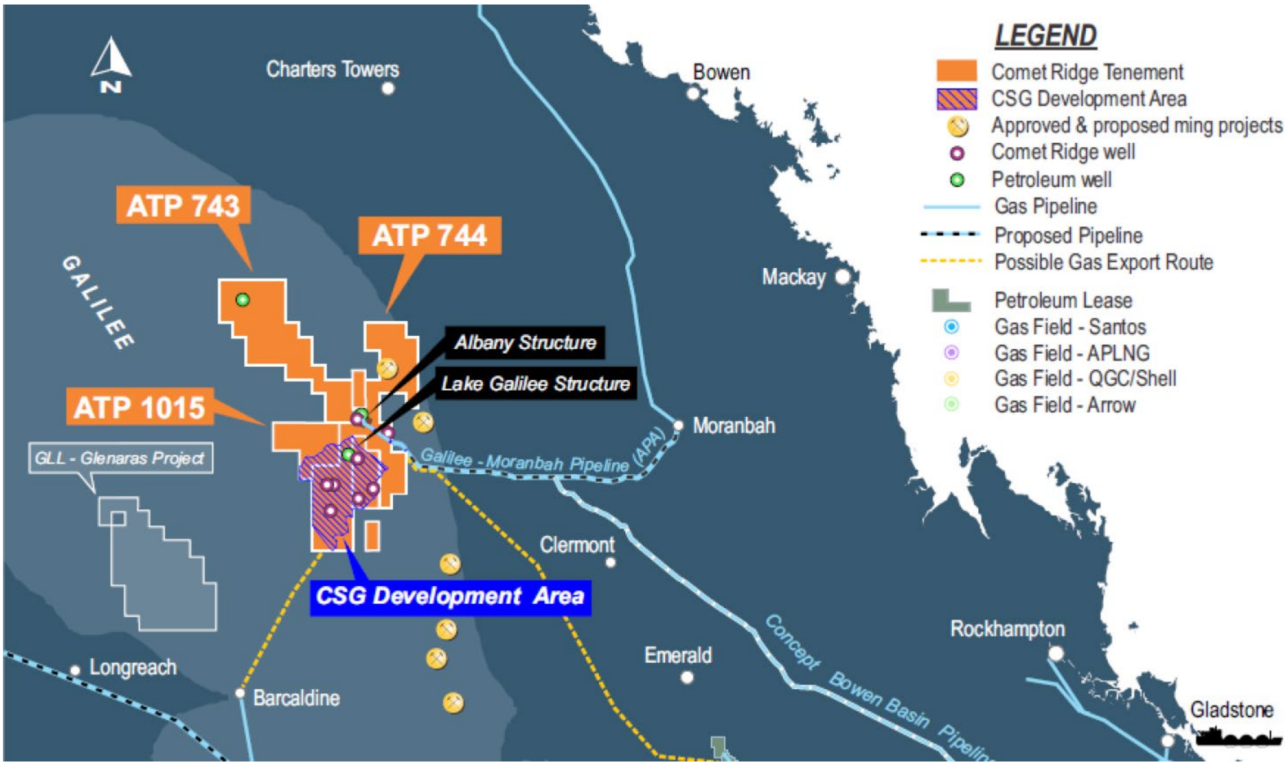


Figure 83 APA Group Galilee Pipeline and project area
(Source: Comet Ridge (2019). Galilee Basin – Galilee Moranbah Pipeline Update. ASX Announcement.)

Blue Energy Pipeline

A pipeline connecting Blue Energy's landholdings in Moranbah to the gas hub of Wallumbilla has been proposed. This option is not well progressed; however Blue Energy have suggested a multi-user, approximately 500km pipeline from Moranbah to Wallumbilla to connect to the Wallumbilla Gladstone Pipeline (WGP) owned by APA. The proposed connection could deliver up to 300 TJ/d into the east coast gas network.

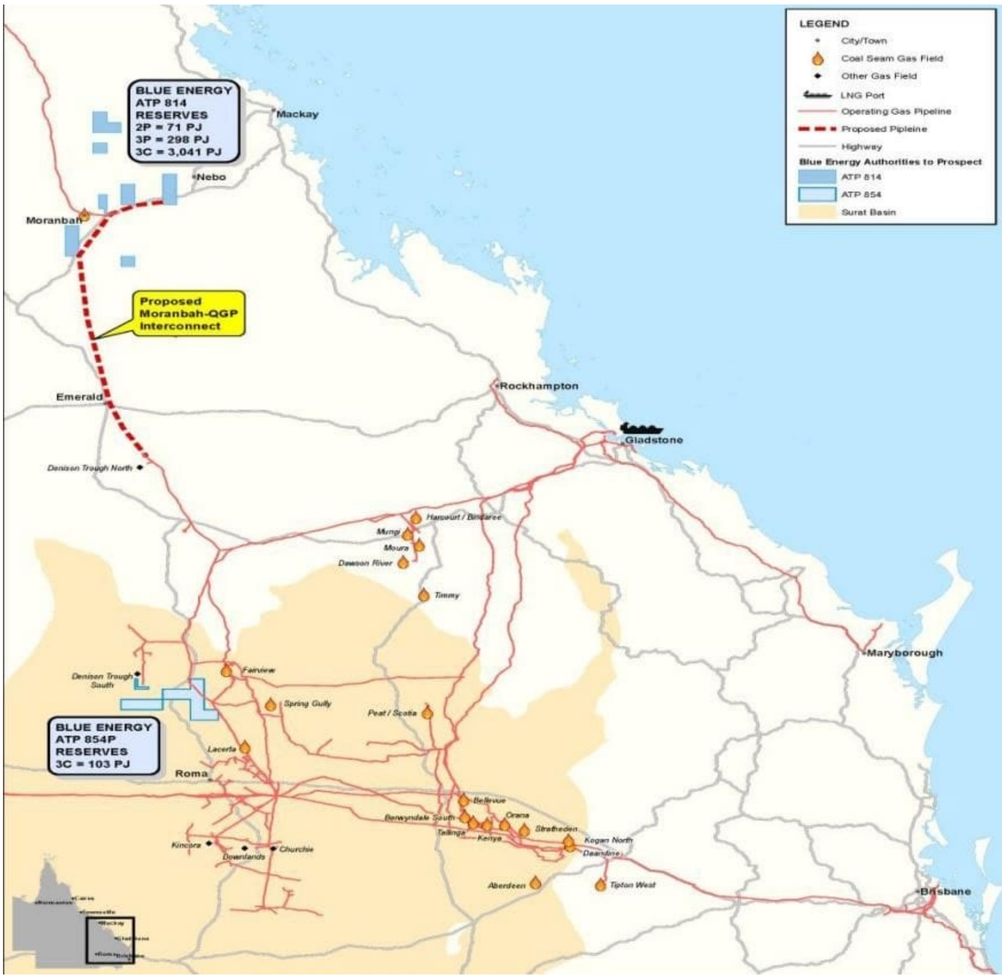


Figure 84 Proposed expansion of Northern Gas Pipeline (Jemena).

(Source: Blue Energy ASX Market Announcement 2020)

Jemena Expansion of Northern Gas Pipeline

Jemena plans to extend their existing Northern Gas Pipeline (NGP), which connects Warrego in the Northern Territory to Mt Isa in Queensland. Completed in 2019, the NGP's current capacity is 90 TJ/d. Jemena's planned expansion could see this increase to up to 1000 TJ/d, through an extension from Mount Isa to Wallumbilla at the southern end and Tennant Creek to Darwin at the northern end (refer Figure 85).

Although this proposed pipeline would supply gas into Wallumbilla, with a potential lateral connection to the Galilee Basin, a link to the Bowen Basin is currently not included.

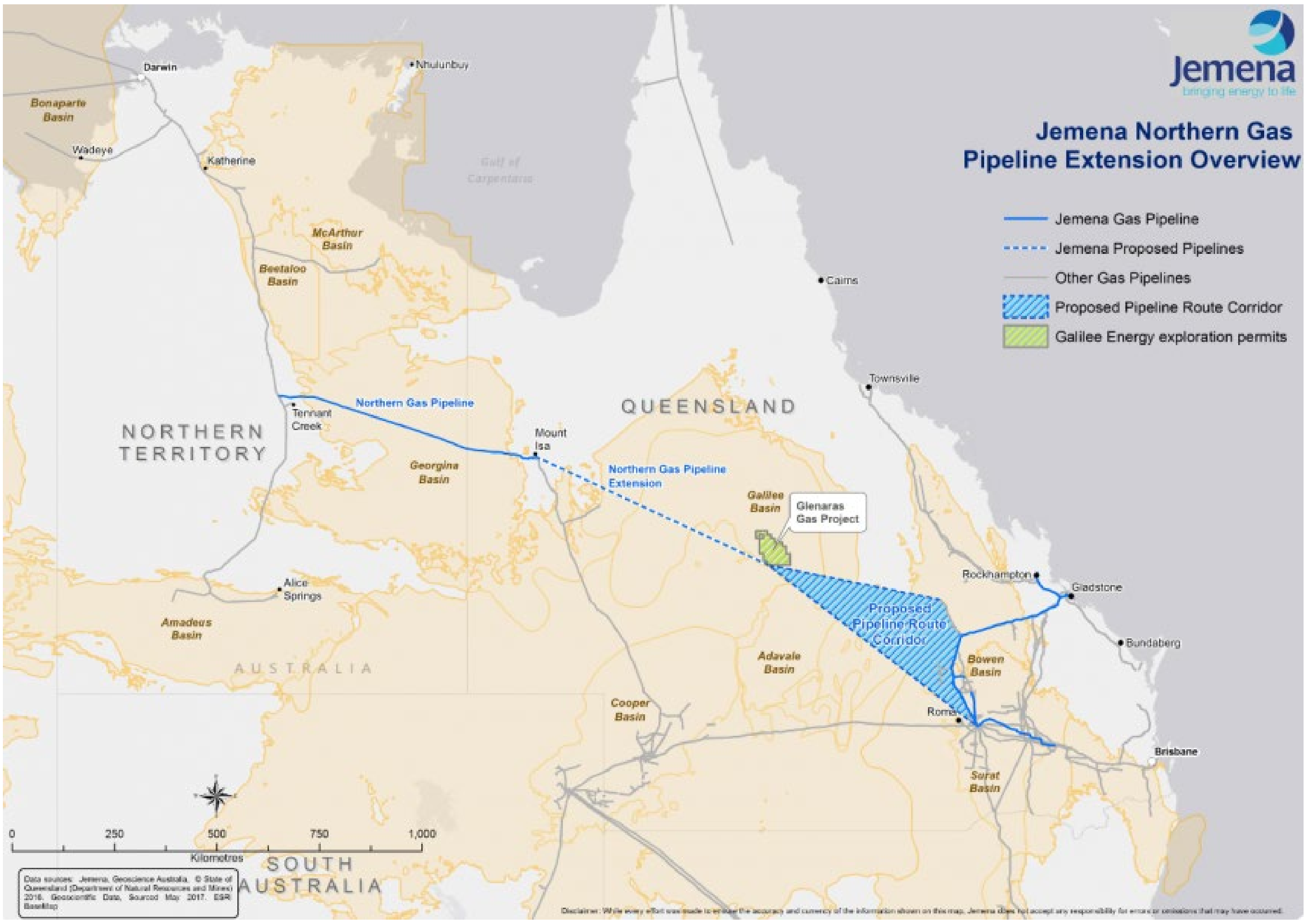


Figure 85 Proposed expansion of Northern Gas Pipeline (Jemena).
(Source: Industry Queensland (2020). Galilee gas deal firms Jemena's pipeline extension plans)

9.3 Concept Study Options

9.3.1 Pipeline route options

Pipeline route options have been developed at a high-level considering a number of criteria as described in Table 26. The routes developed as part of this Study should be considered indicative of likely corridors for a pipeline, it is important to understand that this assessment is provided to confirm that reasonable pipeline corridors exist, to determine the likely length of pipelines to enable estimated pipeline diameters and costs to be developed, and to provide an understanding of key options in macro-level pipeline routing for the Bowen Basin.

Table 26 – Route considerations

(Source: GHD Analysis)

Criteria	Description
Terrain	The terrain traversed by the pipeline can introduce additional design complexity and significantly affect the cost of construction and project schedule. Ideal terrain consists of soft soils and flat, sparse landscapes, as is typical of central Australia. Terrain that is preferably avoided includes mountainous areas, rocky soils, wet soils or bodies of water, contaminated or corrosive soils, areas susceptible to landslides/seismic activity,
Constructability	Pipeline constructability is strongly dictated by the terrain, however additional factors such as access for construction vehicles and proximity to towns has been considered.
Land access	A combination of public and private land may be required to be traversed by the pipeline. Additional land access is also required for the construction right of way. Landowner approval is required for the entire pipeline route. Also, the pipeline route should avoid land subject to native title, cultural heritage or environmental constraints (refer sections 10.3.2-10.3.7 of this report). Existing assets, such as power lines, should be avoided where possible due to land access and design issues.
Land use	Current and future land has been considered, where possible avoiding areas subject to development.
High consequence areas	The pipeline should ideally avoid high consequence areas, defined in AS 2885 (Pipelines-Gas and liquid petroleum) as Residential, High Density, Industrial, Sensitive (such as schools, aged care and hospitals) and Environmental. There are specified design requirements if high consequence areas are unavoidable, however these introduce additional cost to the project as well as increasing project risk.
Proximity to gas producing assets and users	In the case of a multi-user pipeline, it is beneficial to route the pipeline nearby both suppliers and users of the gas, to minimise the length of required lateral pipelines.
Length	Theoretically, the shortest pipeline is the most cost effective, with less pressure drop and materials required for construction. However, due to the factors above the most direct route is usually not entirely feasible, and therefore pipeline length must be optimised alongside the other factors.

Furthermore, indicative routes were considered focusing on the following parameters:

- Start location – This was assumed as connecting to the existing Moranbah Gas Process Facility with a separate connection to the NQGP;
- End locations, focused on connecting to the ECGM;
- Likely coal seam gas production areas within the basin;

- Existing coal mine operations for access to incidental mine gas;
- Environmental no-go zones;
- Geography – avoiding or minimizing exposure to areas such as:
    - mountainous terrain
    - major water courses or major flood plan areas
    - existing mine operations
    - towns
    - National Parks and State Forests
- Pipeline length – minimisation of the pipeline length, whilst consideration of the above items.

These factors were considered most important when considering the maximum utility of coal seam gas production as well as maximising the likelihood of recovery of incidental mine gas. That is, what routing will provide the greatest benefit to achieve the objectives of the scope of work over the life of the basin. It is noted that a pipeline proponent may take a different view for various commercial reasons, and this can be observed in Section 9.2, with some of the differences when comparing the routes below with those previously proposed by potential proponents for Bowen Basin pipelines.

As illustrated in Figure 86 and summarised in Table 27, a number of pipeline options were identified which support the potential development cases described in Section 7. These routes are considered the main options available and should be considered as indicative corridors. It is expected that corridor refinement will occur in subsequent phases of Basin development. The options considered covered the east, central and western extents of the basin. The routes are described in more detail in the following sections.

Table 27 Identified Pipeline Options

(Source: GHD Analysis)

Option	Description	Pipeline Length (km)	Applicable Development Case
Option 1	Moranbah to Gladstone	415	Blackwater region
Option 2A	To Rolleston (West), tie into QGP and GTP	340	Mahalo region Whole of Basin
Option 2B	To Rolleston (East), tie into QGP and GTP	390	Mahalo region Whole of Basin
Option 3	To Moura, tie into QGP and GTP	350	Mahalo region Whole of Basin
Option 4	NQGP	391	Moranbah

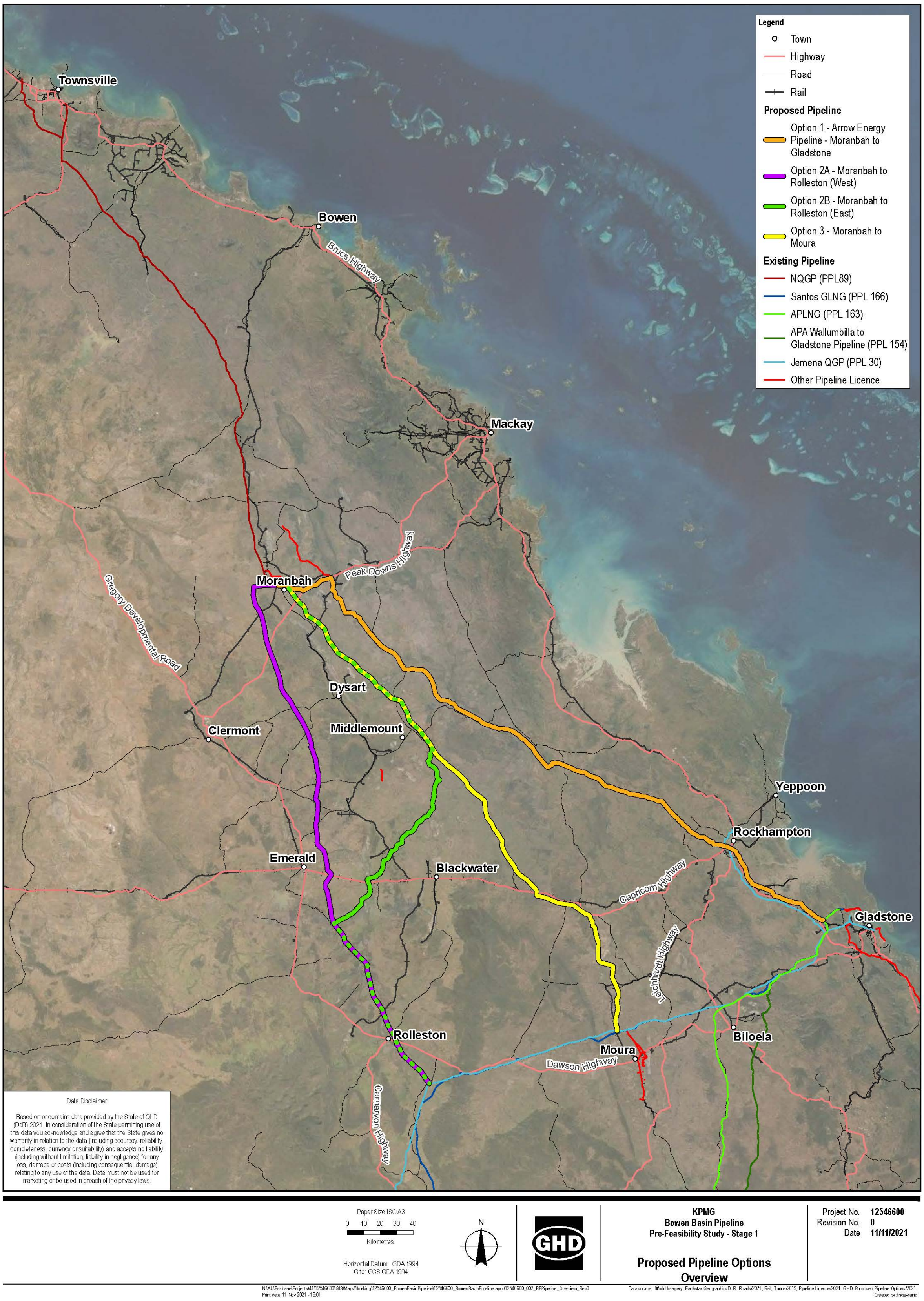


Figure 86 - Identified Pipeline Options

(Source: GHD Analysis)

Route Option 1 – Moranbah to Gladstone

This route largely follows the same route proposed by Arrow for their proposed LNG export pipeline. The route tracks to the east of Basin and connects into the gas transmission pipeline infrastructure in the Gladstone region, the pipeline corridor is assumed to end in the Aldoga area to the west of Gladstone. There is the ability to connect to the pipelines to the LNG facilities as well as the QGP, which delivers gas to a range of customers in the Gladstone region and via lateral pipelines to Rockhampton in the north and Maryborough in the south.

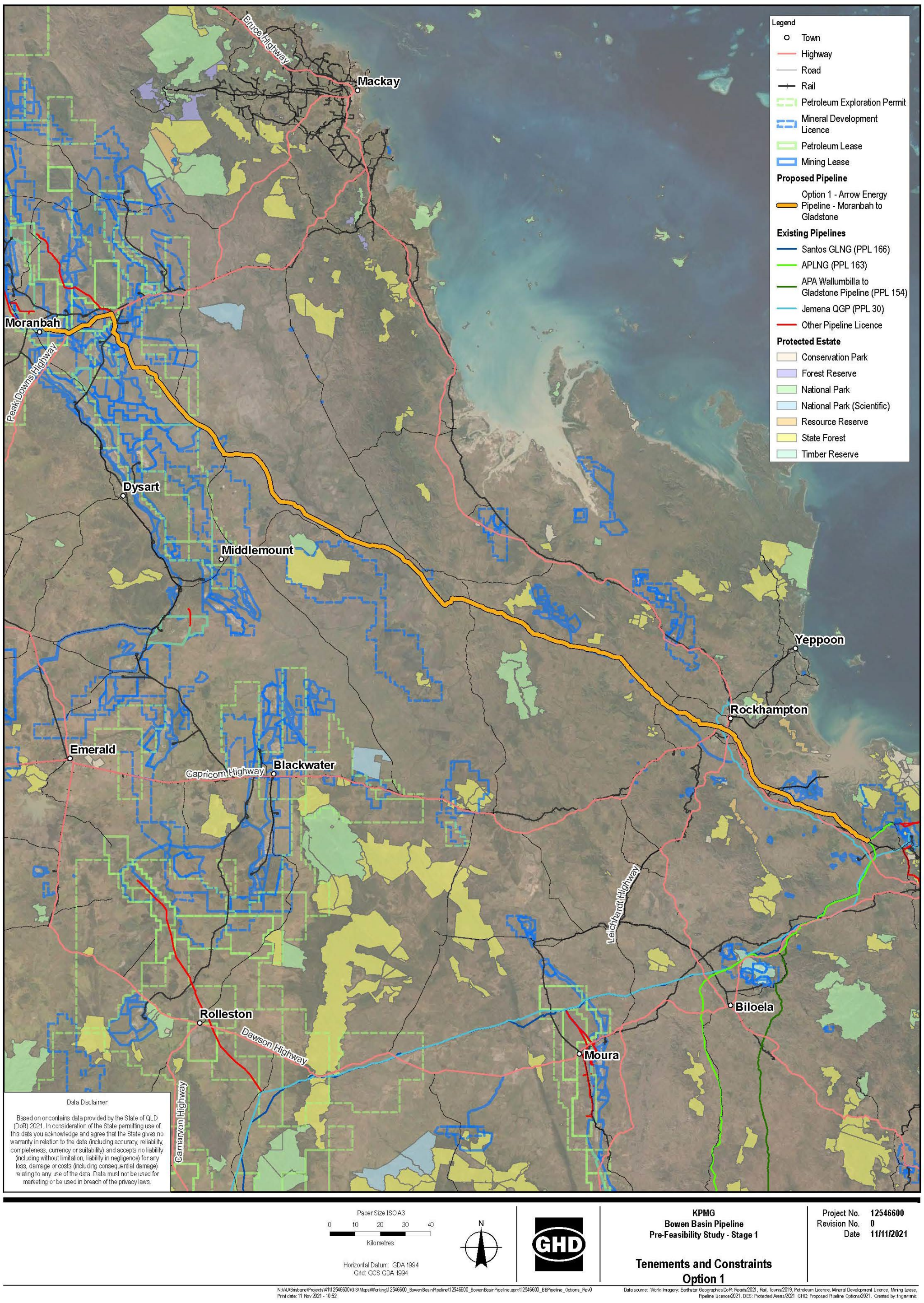


Figure 87 - Option 1 - Moranbah to Gladstone

(Source: GHD Analysis)

Route Option 2A – Moranbah to Rolleston (West)

This route tracks along the west of the Basin and is the most direct route to joint into the existing transmission pipelines that transit near the town of Rolleston. This route avoids the mountain ranges that are between Moranbah and Middlemount, running near the town of Emerald. Whilst this route is the shortest, it is west of the existing coal mines and potential coal seam gas resource in the order of 20 to 30 km for the first half of the route. The route picks up the prospective Mahalo and Mahalo North areas.

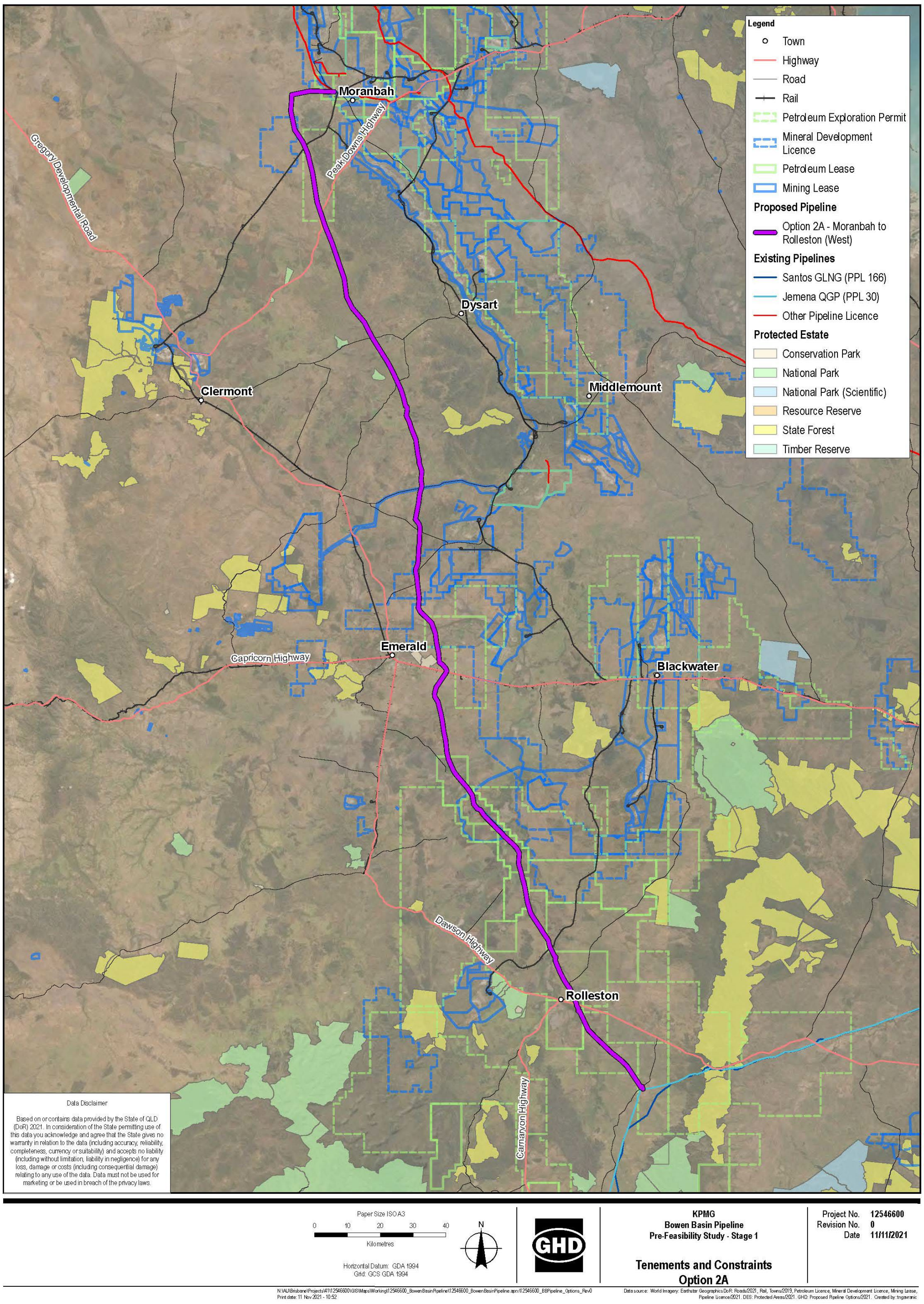


Figure 88 - Infrastructure Option 2A – To Rolleston (West)

(Source: GHD Analysis)

Route Option 2B – Moranbah to Rolleston (East)

This route tracks through the centre of the Basin to the Blackwater area, and then turns westward to route past the prospective Mahalo and Mahalo North areas before connecting into the existing transmission pipelines that transit near the town of Rolleston. This route is 40 km longer than the most direct route, and is likely to be the most complex route, as it will need to consider many mine and other gas leases, and existing infrastructure that service the mine operations.

However, as this option traverses more potential gas reserves particularly in the Blackwater region, and offers the greatest potential CMM capture, the upside is considered to outweigh the risk when considering the objectives of this study.

Although processing CMM for pipeline export is an unlikely use case when compared to power-generation, this route option presents the best opportunity to do so compared to other route options. Additionally, improving the pre-drainage of open cut mines would be more likely if there were a local pipeline to access, as is provided by this option.

Therefore, this route is the preferred route by this study.

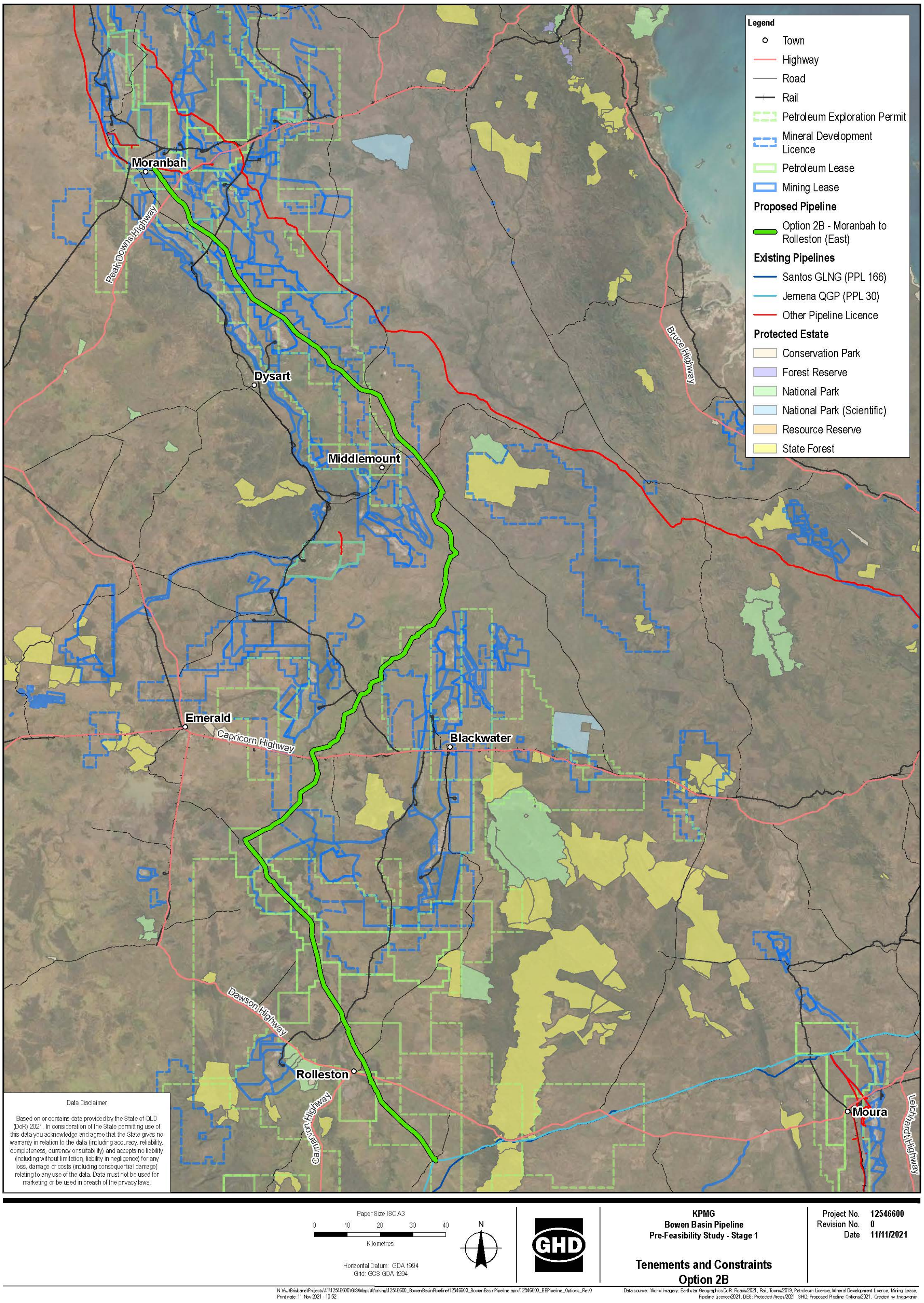


Figure 89 - Infrastructure Option 2B – To Rolleston (East)

(Source: GHD Analysis)

Route Option 3 – Moranbah to Moura

This route tracks through the centre of the basin to the Blackwater area, and then stays on reasonably constant trajectory toward the east side of the basin before connecting into the existing transmission pipelines that transit to the north of the town of Moura. This route is 10 km longer than the most direct route, the southern half of this route is not expected to be a prospective for gas sources as Route Option 2B as there are limited mine or petroleum leases between Blackwater and Moura.

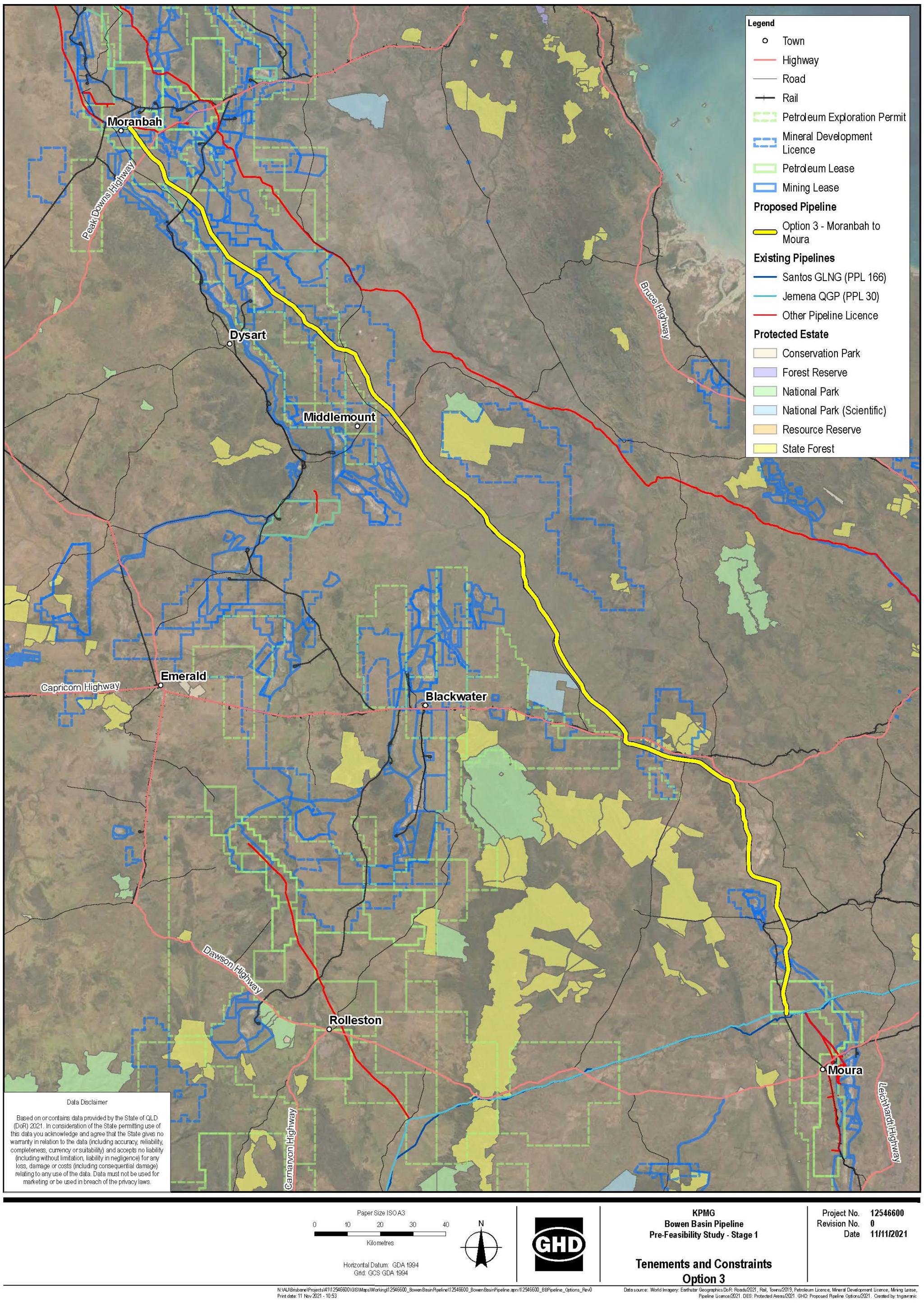


Figure 90 - Infrastructure Option 3 – To Moura

(Source: GHD Analysis)

Option 4 – No new pipeline

This route is included for completeness, this is the existing route of the QGP. This route is on the western side of the Basin and the existing petroleum and mine leases. It is expected that it would require lateral pipelines to connect any new gas production developments to the north of Moranbah. The lateral pipelines could be between 10 km to 40 km in length.

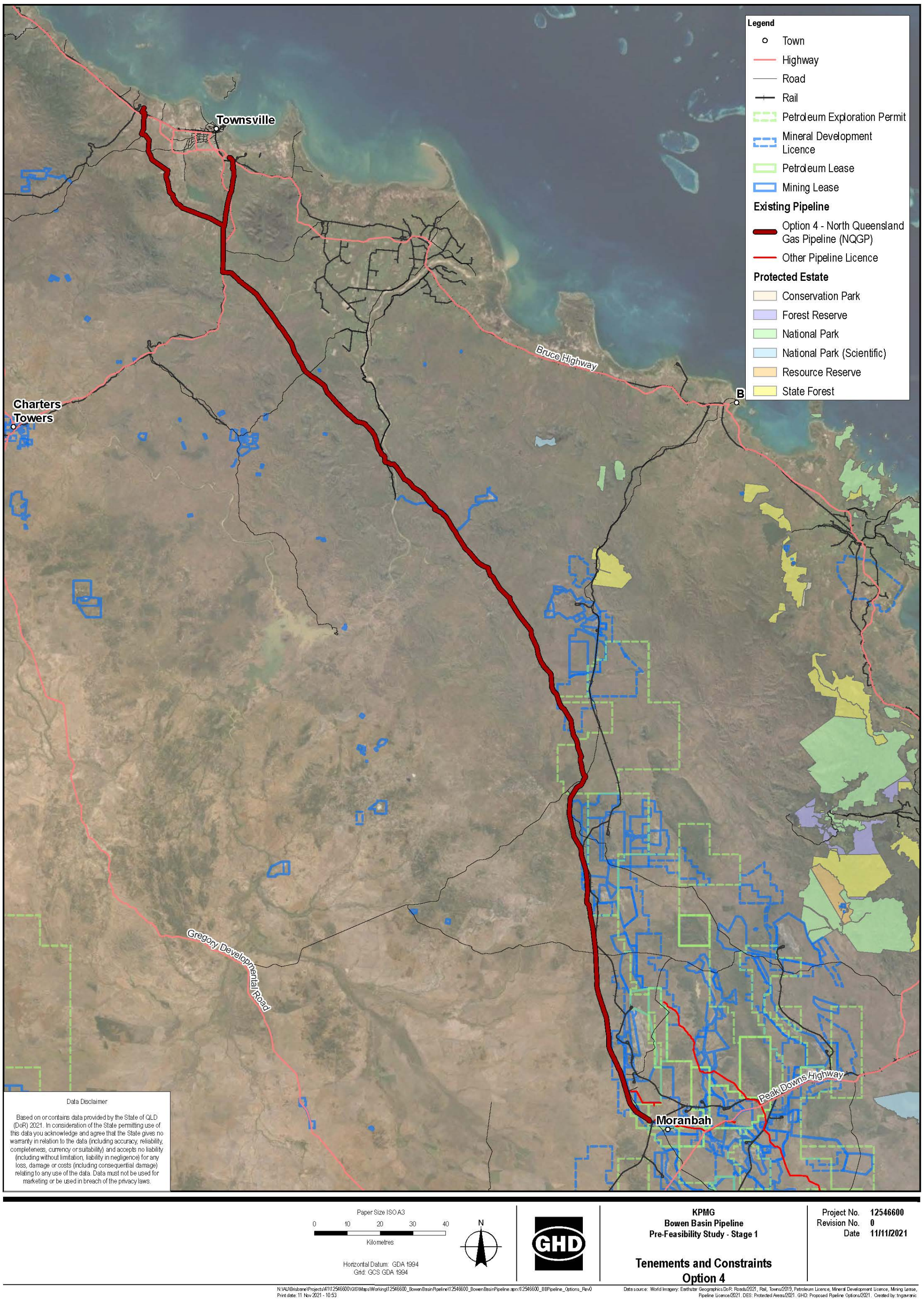


Figure 91 - Option 4 – No new pipeline

(Source: GHD Analysis)

9.3.2 Preliminary route assessment

The selection of a particular pipeline route from one point to another requires a multi-criteria assessment to optimise the many constraints. Route selection is ultimately an iterative process requiring consultation between landowners, regulatory bodies, pipeline owner, engineers, constructors and other project stakeholders. However, to inform the outcomes of this Study, a Strategic Merit Test (SMT) was undertaken. The SMT was used to filter options according to their ability to meet the Study's objectives for the development of the Basin. A SMT is not intended to be comprehensive, but is an initial check of project options for strategic merit that:

"Rules an option in or out at an early stage of the assessment process; and identifies those options that should proceed to the next stage of the appraisal, options that require further work and those that should be abandoned because they are inconsistent with the jurisdiction's objectives and strategies"

Figure 92 below summarises the results of the SMT. The assessment criteria were selected to reflect the ability of the pipeline route to address the Government's objectives for the Basin of:

- Improving surface economic viability of gas production and providing gas to market to deliver shared benefits for the region and the State as a whole;
- Delivering efficient, multi-user gas transport infrastructure that will unlock gas resources;
- Enhanced commerciality of gas field developments in the Basin;
- Future-proofing gas supplies in Queensland; and
- Better management of incidental coal mine gas.

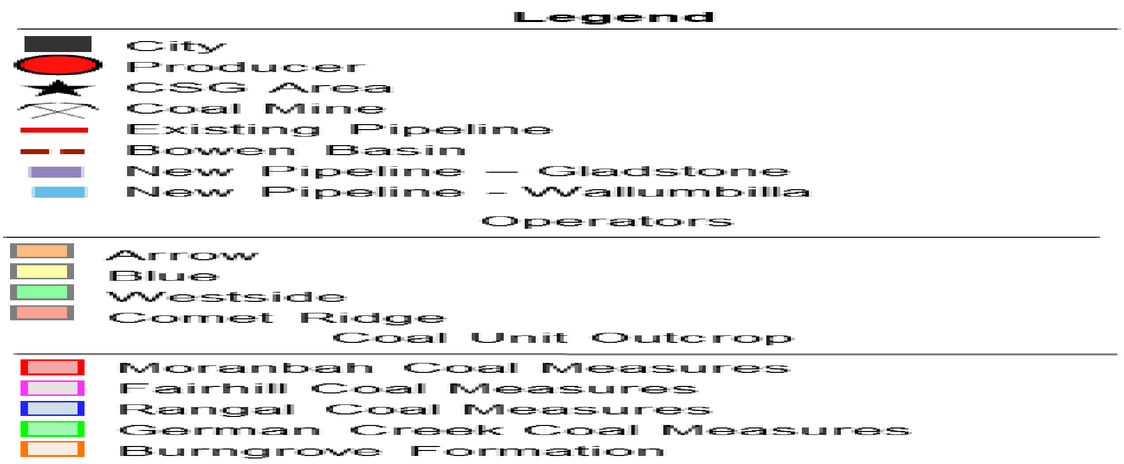


Figure 92 – Strategic Merit Test

Gas to market

Due to the need to service the expected shortfall of gas supplies into the ECGM by the mid-2020s, the assessment was based on connecting the Bowen Basin to the ECGM. Whilst forecasts from AEMO can and do move around with time, given they are a snapshot of a dynamic market, the overall conclusions from our analysis are that there is a trend of supply/demand gaps emerging beyond the end of this decade, and that more gas is needed based on current demand forecasts.

Option 1 would be more effective for export of gas via LNG through its connection to Gladstone. Options 2A, 2B and 3 with a connection to Wallumbilla, would be more effective for supply to the ECGM.

There is a higher capex involved for Option 2B but there is a greater upside with more gas being able to access the pipeline. Option 2B would be able to capture more of the gas suitable for pipeline injection from Moranbah, Blackwater and Mahalo regions, when compared to Option 2A. Option 2A presents a similar opportunity, however, it is expected that it would be more difficult economically to access gas resources in the Blackwater region.

Although, it is noted that once a connection is made into a pipeline, there are commercial ways to get contractual gas flows to the customer within the ECGM or to LNG export (location-based gas swaps).

Unlocking gas resources

The assessment was based on the number of gas permits the pipeline route supports.

When considering the options, Option 1 with a connection to Gladstone does not effectively capture the majority of gas permits in the Basin, supporting only the unlocking of the Moranbah region. Furthermore, it would require a significant gathering network and large processing facilities in Moranbah.

Options 2A and 2B with a connection to Wallumbilla support a whole-of-Basin solution, passing close to many existing exploration permits across both the Blackwater and Mahalo regions. Due to the close proximity of the existing exploration permits, these options also require a less significant gathering network, with several smaller processing facilities for local tie-in to the pipeline.

Although Option 3 provides a connection to Wallumbilla from Moranbah, as there are limited mine or petroleum leases between Blackwater and Moura, the southern half of this route is not expected to be as prospective for gas sources as Route Option 2B.

Capturing incidental coal mine gas

Options 2A and 2B run in close proximity to the existing exploration permits and maximise the utility of methane from coal in the Basin, from both mining operations and coal seam gas production. Option 2B provides the closest access to the majority of the prospective resource and is considered the route which maximises the capture of incidental coal mine gas. As described above, the southern half of Option 3 is due to the limited mine or petroleum leases between Blackwater and Moura.

Due to its alignment, there is limited opportunity for Option 1 to capture incidental coal mine gas.

Supporting regional development

By supporting the development of the whole Basin, Options 2A, 2B and 3 offer a range of regional development opportunities. By only supporting the development of the Blackwater region and its supply of gas predominately to the LNG export market, Option 1 is considered to result in minimal regional development opportunities.

When considering the Government's objectives for the Basin as part of this Study, based on the above SMT, **Option 2B delivers the greatest alignment to these strategic outcomes**.

9.3.3 Pipeline sizing methodology

The sizing basis used for the gas pipelines used the typical approach applied to sizing gas pipelines and relied on experience gained over several decades, including specific experience with coal seam gas. The assessment assumed that a gas compression facility is require at the end of the Bowen Basin Pipeline, this is to enable gas to be injected into the existing pipelines that are connected to the East Coast Gas Market.

Key parameters used in the sizing including the following:

- Pipeline surface roughness consistent with typical practice in Australia – this is used to determine the pressure loss in the pipeline

- Maximum gas velocity limit at the pipeline outlet consistent with typical practice in Australia – this a key design limit used in pipeline sizing
- A pipeline Maximum Allowable Pressure of 10.2 MPag – This pressure is more typical for gas transmission pipelines in coal seam gas application and enables a materially lower gas compression ratio at the gas processing facilities.
- Gas composition was typical coal seam gas composition for Queensland.

Bowen Pipeline Technical Parameters

The preliminary technical details for the new pipeline corridor options, for a range of possible flowrates, are shown in Table 28.

Table 28 - Indicative Pipeline Technical Parameters

(Source: GHD Analysis)

Route Option	Length (km)	Inlet Pressure (MPag)	Outlet Pressure (MPag)	Flow (TJ/d)	Diameter
Moranbah to Gladstone (Option 1)	415	15.3	7.0	50	DN250
				100	DN350
				150	DN450
				200	DN500
				250	DN550
				300	DN600
Moranbah to Rolleston (West) (Option 2A)	340	10.2	5.0	50	DN250
				100	DN400
Moranbah to Rolleston (East) (Option 2B)	390			150	DN450
				200	DN550
Moranbah to Moura (Option 3)	350			250	DN600
				300	DN650
Moranbah to Townsville (Option 4) *(note 1)*	391	15.3 (max)	5.0	108 TJ/d	DN 300

1. Option 4 refers to the existing NQGP, and no new pipeline is proposed for this option.

The maximum allowable operating pressure for the proposed Arrow Bowen Pipeline from Moranbah to Gladstone was presumed to be 15.3 MPag.

Operating pressures considered for proposed pipeline routes between Moranbah and Rolleston were indicative and were predominantly based on Queensland Gas Pipeline (QGP) operating data. A preliminary value of 10.2 MPag was considered matching that of typical QGP operating conditions.

9.4 Commercial

9.4.1 Approach to estimating

Estimation of capital costs for the infrastructure has used a factored approach, which is consistent with the industry approach for concept studies, where costs are used to inform options and the likely overall costs for a project.

The basis used for this report uses the following rates for each the following elements of the gas production and pipeline infrastructure. The assumed configuration of the gas producing assets was on a fit-for-purpose basis, where engineering specifications are such that the asset delivers a reasonable level of reliability and complies with the minimum industry standards. The rates used are considered as representative of efficient cost rates that would be observed under reasonable market conditions for construction, i.e. an average level of resource project construction across Australia.

The unit rates for capex calculations were as follows:

1. Cost rates for well connection costs which include flowlines and well pad facilities were considered as $1 to 1.5 million per well connection (note this is additional to the well drilling costs stated in Section 7.1.2).
2. Cost rates for gas processing facilities were considered as $3 to $4 million per TJ/day capacity.
3. Cost rates for pipelines were considered as $70,000 per inch per kilometre.

9.4.2 Capital Expenditure

Estimated capital expenditure (Capex) for various identified pipeline options are presented below.

Table 29 - Option 1 – Moranbah to Gladstone Gas Infrastructure
(Source: GHD Analysis)

Parameter	Moranbah + Blackwater
Flowrate	**225 TJ/d** (150 TJ/d Moranbah + 75 TJ/d Blackwater)
Required Infrastructure	~ 1,700 wells & gathering network 1 x new gas processing facilities Expansion of MGP DN500, 415 km pipeline operating at 15.3 MPag
Estimated Capital Expenditure	Wells/gathering: $1-1.5M per well Processing facilities: $700M Pipeline: $580M
Development Timeline (best case)	5 years
Risks	Viability of wells in central Bowen is unknown Final ¾ of pipeline route does not utilize gas or mining assets No incremental development possible – all or nothing

Notes:

1. *Compression has only been allowed for at the GPFs.*
2. *Blackwater gas is assumed from the norther area of Blackwater closest to the pipeline route*
3. *Pipeline capacity could be expanded in the future up to 400 TJ/d by adding mainline compressor stations.*

4. *Of the 200 TJ/d from the Moranbah region as stated in the production scenarios (refer Figure 6), 50 TJ/d has been assumed to be transmitted North via the NQGP, with the remainder being transmitted via the new pipeline to Gladstone.*

Table 30 - Option 2A – To Rolleston (West) Gas Infrastructure

(Source: GHD Analysis)

Parameter	Mahalo	Mahalo + Moranbah
Flowrate	180 TJ/d	**300 TJ/d** (Mahalo 150 TJ/d + Moranbah 150 TJ/d)
Required Infrastructure	~ 1,158 wells & gathering network 2 x new gas processing facilities End of line compression (~7 MW) DN400, 140 km pipeline operating at 10.2 MPag	~ 2,000 wells & gathering network 3 new gas process facilities and MGP expansion End of line compression (~ 8MW) DN550, 340 km pipeline operating at 10.2 MPag
Estimated Capital Expenditure	Wells/gathering: $1-1.5M per well Processing facilities: $630M Pipeline: $160M	Wells/gathering: $1-1.5M per well Processing facilities: $1,155M Pipeline: $520M
Development Timeline (best case)	4 years	6 years
Risks	Would need to oversize initial southern pipeline (to DN550), or loop in the future, or add additional future compression, to unlock Moranbah. Additional upfront cost on oversized pipeline adds ~40% to pipeline cost only.	Viability of wells in central Bowen is unknown, pipeline would need to extend to Moranbah for proven resources Route does not optimize proximity to mines / gas resources in Middlemount & Blackwater areas

Notes:

1. *Compression has only been allowed for at the GPFs and end of line to tie into QGP.*
2. *Pipeline capacity could be expanded in the future up to 400 TJ/d by adding mainline compressor stations.*
3. *Of the 200 TJ/d from the Moranbah region as stated in the production scenarios (refer Figure 6), 50 TJ/d has been assumed to be transmitted North via the NQGP, with the remainder being transmitted via the new pipeline to Gladstone.*

Table 31 - Option 2B – To Rolleston (East) Gas Infrastructure

(Source: GHD Analysis)

Parameter	Mahalo	Mahalo + Blackwater + Moranbah
Flowrate	180 TJ/d	**375 TJ/d** (Mahalo 150 TJ/d + Blackwater 75 TJ/d + Moranbah 150 TJ/d)
Required Infrastructure	~ 1,158 wells & gathering network 2 x new gas processing facilities End of line compression (~7 MW) DN400, 140 km pipeline operating at 10.2 MPag	~ 2,400 wells & gathering network 4 x new gas processing facilities and MGP expansion End of line compression (~ 9MW) DN550, 390 km pipeline operating at 10.2 MPag
Estimated Capital Expenditure	Wells/gathering: $1-1.5M per well Processing facilities: $630M Pipeline: $160M	Wells/gathering: $1-1.5M per well Processing facilities: $1,225M Pipeline: $600M
Development Timeline (best case)	4 years	6 years
Risks	Would need to oversize initial southern pipeline (to DN550), or loop in the future, or add additional future compression, to unlock Moranbah. Additional upfront cost on oversized pipeline adds ~40% to pipeline cost only.	Viability of wells in central Bowen is unknown, pipeline would need to extend to Moranbah for proven resources Constructability of pipeline route through Middlemount & Blackwater due to mines

Notes:

1. *Compression has only been allowed for at the GPFs and end of line to tie into QGP.*
2. *Pipeline capacity could be expanded in the future up to 400 TJ/d by adding mainline compressor stations.*
3. *Of the 200 TJ/d from the Moranbah region as stated in the production scenarios (refer Figure 6), 50 TJ/d has been assumed to be transmitted North via the NQGP, with the remainder being transmitted via the new pipeline to Gladstone.*

Table 32 - Option 3 - To Moura Gas Infrastructure

(Source: GHD Analysis)

Parameter	Blackwater + Moranbah
Flowrate	**225 TJ/d** (Blackwater 75 TJ/d + Moranbah 150 TJ/d)
Required Infrastructure	~ 1,600 wells & gathering network 2 x new gas processing facilities and MGP expansion End of line compression (~ 8MW) DN500, 350 km pipeline operating at 10.2 MPag
Estimated Capital Expenditure	Wells/gathering: $1-1.5M per well Processing facilities: $700M Pipeline: $490M
Development Timeline (best case)	6 years
Risks	Viability of wells in central Bowen is unknown, pipeline would need to extend to Moranbah for proven resources Constructability of pipeline route through Middlemount & Blackwater due to mines

Notes:

1. *Compression has only been allowed for at the GPFs and end of line to tie into QGP.*
2. *Pipeline capacity could be expanded in the future up to 400 TJ/d by adding mainline compressor stations.*
3. *Of the 200 TJ/d from the Moranbah region as stated in the production scenarios (refer Figure 6), 50 TJ/d has been assumed to be transmitted North via the NQGP, with the remainder being transmitted via the new pipeline to Gladstone.*

Table 33 - Option 4 - No new pipeline

(Source: GHD Analysis)

Parameter	Moranbah
Flowrate	50 TJ/d
Required Infrastructure	265 wells & gathering network Upgrade of Moranbah Gas Processing facility No new pipeline – use NQGP Pipeline No end of line compression
Estimated Capital Expenditure	Wells/gathering: $ 1-1.5M per well Processing facilities: $175M Pipeline: Nil
Development Timeline (best case)	3 years
Risks	Lack of gas demand in Townsville

9.4.3 Operating Expenditure

Annual operating expenditure (Opex)for the gas infrastructure is based on high-level benchmarks that are used in the industry. For this level of assessment is it typical to use a percentage of capital cost as the annual operating expenditure estimation. These cost are all inclusive, and cover items such as:

- Field labour;
- Vehicles and machinery;
- Maintenance and consumables;
- Energy (electricity or gas) for powering facilities and compression;
- Utilities;
- Support staff;
- Insurance; and
- Overheads.

These operational expenditure rates are as follows:

- Gas production systems annual operating expenditure, inclusive of well pads, gathering system, gas process facility and produced water handling – 5% to 10% of gas production system initial Capex (excludes sustaining well connections).
- Gas pipeline annual operating expenditure – 1% to 2% of pipeline Capex.

It is noted that there are many factors that can change the annual operating expenditure, however the amounts defined above are considered appropriate for an efficient operator.

9.4.4 Sensitivities

Key sensitives include the following capex items:

- Number of wells to be connected;
- Gas process facility complexity;
- Distance of gas source from gas pipeline; and
- Pipeline route length.

The most significant sensitivity is the number of wells to be connected, driven by uncertainty in well productivity, as this will materially alter the cost of the overall basin development. This cost includes the wells to be drilled, well pads and gathering system to connect the well pad to the gas process facility. Whilst the unit cost of wells is known with a reasonable level of certainly, and each well and associated connecting will have a cost variation likelihood, given the large quantity of well connections it is typical the aggregated potential cost variation is materially less than the unit average. It is the number of wells required to produce an aggregated gas flow rate that will produce the largest cost change, given this is the highest area of uncertainty. This is a cost sensitivity that is highest in coal seam gas production, when compared to other forms of onshore gas production, given the typical range of flow per well.

The other key capex items will have sensitivities; however these are likely within a range in the order of 30% around the estimated numbers. Given these costs are less than half of the total costs of the basin development, the sensitivity is substantially less than the productivity of the wells.

Opex is generally not a material sensitivity for gas developments given the percentage it contributes to total project lifecycle costs in the order of 15% to 20%, therefore a material change in annual opex generally results in a modest change in the project lifecycle costs.

9.4.5 Enablers and challenges

The following table summarises the key enablers and challenges for the identified pipeline route options.

Table 34 - Enablers and Challenges

(Source: GHD Analysis)

Infrastructure Option	Enablers	Challenges
Option 1 Moranbah to Gladstone	Proven gas resources & well viability	Final ¾ of pipeline route does not optimize access to gas or mining assets No incremental development possible – all or nothing Highest capital expenditure relative to flowrate.
Option 2A To Rolleston (West)	Enables staged development, requiring less upfront capital	Route does not optimize proximity to mines / gas resources in Middlemount & Blackwater Would need to oversize initial southern pipeline (to 22 in.) to unlock full future potential, or install future mainline compression, or loop pipeline.
Option 2B To Rolleston (East)	Enables staged development, requiring less upfront capital Provides mines access to gas transmission infrastructure	Constructability of pipeline constrained through mining operations & leases
Option 3 To Moura	Enables staged development, requiring less upfront capital Provides mines access to gas transmission infrastructure	Constructability of pipeline constrained through mining operations & leases Southern section to Moura does not unlock any new gas resources
Option 4 No new pipeline	Lowest capital investment Proven gas resources & well viability Shortest development timeline	Lack of gas demand in Townsville Future expansion requires new pipeline Does not improve capture of coal mine gas – separate infrastructure required

Key insights from the table above include the following:

- There are a number of ways to route a pipeline from the Bowen Basin to connect into the East Coast Gas Market, there are pros and cons of each option.
- The likely cost variation, for a like for like pipeline, is broadly a percentage of the route length variation. Given the maximum variation in length of the options is in the order of 20%, then the range of capital cost variation will be in this range.
- The most easterly and westerly routes have the least ability to enable the maximum utility of coal seam gas production and use of incidental mine gas pre-drainage, due to proximity.
- Option 2A and 2B enables staged development in a South to North manner, on the basis that the Mahalo and Mahalo North projects are developed. This could provide a staged development, to enable southern section of the basin to be developed earlier than may occur with a full basin pipeline. None of the other identified options appear to provide this flexibility.

10. Approval requirements

Project approvals can be considered a function of the nature, extent and magnitude of proposed project activities, associated disturbance footprint and impact. There are corollary approval requirements which also need to be satisfied in order to enter/access land to undertake the proposed project activities.

Regardless of the corridor option nominated for the proposed Bowen Basin Gas Pipeline, numerous Tier 1, 2 and 3 planning and environmental approvals, at the Commonwealth and State level, will need to be obtained for the project.

Broadly speaking, Tier 1, 2 and 3 approvals can be described according to the following:

- **Tier 1**: Major approvals required to enable the overall project e.g. Environmental Approval by State and Commonwealth Governments, Petroleum & Gas Lease, Native Title consent
- **Tier 2**: Approvals relating to specific project elements with long durations and requiring a high level of project definition e.g. Land use (development) consent, resource entitlements, permits for operational works, and permits for removal of vegetation
- **Tier 3:** Construction approvals e.g. registration certificates, licence to store flammable or combustible goods on premises, navigational aids approvals, etc

Tier 1 approvals are typically obtained first as they incorporate much of the supporting information for Tier 2 and 3 approvals.

10.1 Key Legislation and Approval Options

The following sections outline the typical project approval pathways for major energy and resource projects. As individual project design and scale are clarified, and inputs from agencies received, the approvals required will need to be reassessed.

Projects of this nature and scale would typically opt for declaration as a "Coordinated Project" under the *State Development and Public Works Organisation Act 1971* (SDPWO Act) and will undertake an EIS under the Queensland and Commonwealth Government bilateral arrangement for environmental assessment. This pathway tends to offer the most efficient and streamlined approach for major project approvals.

Refer to Appendix C for the breakdown on the potential approval requirements.

Approvals Process Flow

A high-level project approval process, likely to be relevant to a project of this nature, is shown in Figure 93. Approval processes may be able to be run concurrently with other project aspects but the benefit and practicality of this needs to be assessed based on the proposed project staging, selected approvals pathway and the project delivery timeframes.

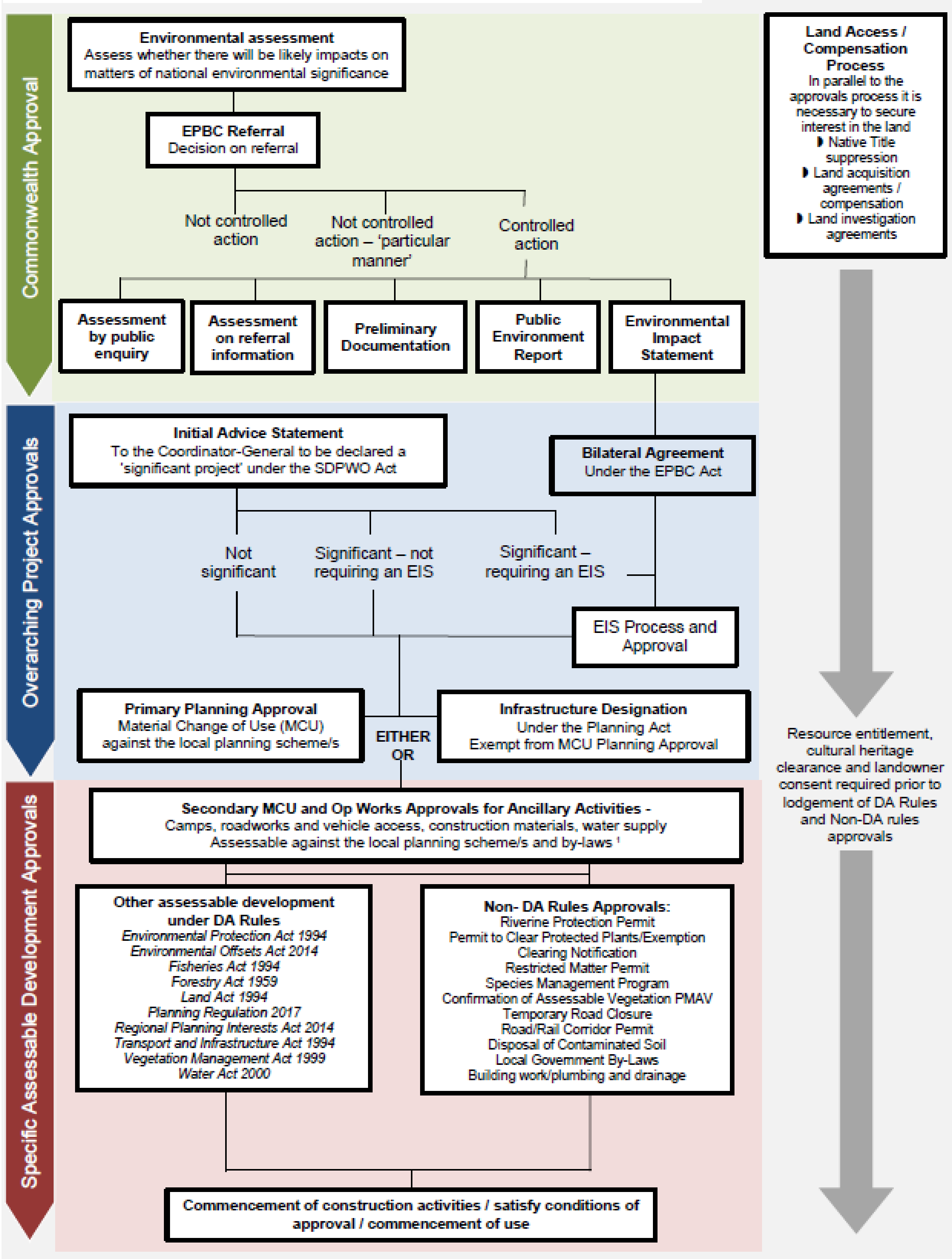


Figure 93 Approvals Pathway Flow Diagram

(Source: GHD Analysis)

Designated Corridor

There is potential for the Queensland Government to designate an infrastructure corridor to fast-track development within the Basin. This infrastructure corridor would enable not only pipeline development, but utilities development as well including gas, power and water.

The coordination and declaration of a State Development Area (SDA) would provide many benefits with regards to the establishment of a gas pipeline in the Bowen Basin including:

- Provides greater certainty about approval processes
- Ensures the land was safeguarded from inappropriate uses
- Offers coordination with the private landholders including consultation to determine the preferred corridor alignment and negotiation of an easement
- Provides acquisition of an easement through the privately owned land and provision of a license to the LNG proponents for the construction and operation of the pipeline
- Minimisation of impacts to landholders and the environment through efficient use of land
- Minimises risks of project delays from third party legal challenges.

10.2 Likely Suite of Approvals Required

A significant number of environmental and planning approvals are required for major petroleum and gas projects in Queensland to proceed, with the most critical approval being the EIS. An effective and proactive Government engagement program is essential also to manage approvals and mitigate the potential for approval delays. The complexity of major petroleum and gas projects also requires an effective interface between the proponent, community consultation team, environmental specialists and the engineering teams. This is necessary to manage approvals issues that may arise.

Table 35 below lists the indicative key legislative requirements triggered by works to support major petroleum and gas projects in Queensland, noting this list is not exhaustive. The exact number, type and nature of the approvals required for a project will not be completely known until site selection occurs.

Table 35 Indicative Legislative Requirements
(Source: KPMG Analysis)

Legislative Requirement	*Relevant Legislation*	Administrator
Commonwealth Approvals		
Approval of a controlled action	*Environment Protection and Biodiversity Conservation Act 1999*	Department of Agriculture, Water and the Environment (DAWE)
Permission to impact on land where native title has not been extinguished	*Native Title Act 1993*	Native Title Tribunal
Permission to intervene in matters where traditional cultural heritage interests are considered to be at risk	*Aboriginal and Torres Strait Islander Heritage Protection Act 1984*	DAWE
Reporting under National Greenhouse and Energy Reporting Scheme (NGERS)	*National Greenhouse and Energy Reporting Act*	Clean Energy Regulator

Legislative Requirement	*Relevant Legislation*	Administrator
State Approvals		
Coordinator-General's EIS evaluation report	*State Development and Public Works Organisation Act 1971*	Coordinator General
A Cultural Heritage Management Plan (CHMP) or native title agreement	*Aboriginal Cultural Heritage Act 2003*	Department of Environment and Science (DES)
Development Permit for Operational Works for work within a Coastal Management District	*Coastal Protection and Management Act 1995, State Coastal Management Plan, Planning Act 2016 and Planning Regulation 2017*	DES and relevant local council
Approval for the removal or placement of quarry material below high-water mark	*Coastal Protection and Management Act 1995, State Coastal Management Plan, Planning Act 2016 and Planning Regulation 2017*	DES
Approval to damage vegetation on State coastal land	*Coastal Protection and Management Act 1995*	DES
Permit for the handling, storage and manufacture of hazardous materials, and dangerous goods	*Dangerous Goods Safety and Management Act 2001*	Department of Emergency Services
Notice prior to carrying out work affecting electricity entity's works	*Electricity Act 1994*	Relevant Electricity Entity
Undertaking a prescribed activity as per the for which there will be a significant residual impact on one or more prescribed environmental matters	*Environmental Offsets Act 2014*	DES
Environmental authority for undertaking an environmentally relevant activity	*Environmental Protection Act 1994 and Environmental Protection Regulation 2019*	DES
Development Permit for a Material Change of Use of premises for environmentally relevant activities	*Environmental Protection Act 1994, Environmental Protection Regulation 2019 and Planning Act 2016*	DES
Development Permit for a Material Change of Use of premises for development on contaminated land	*Environmental Protection Act 1994 and Planning Act 2016*	DES
Disposal permit to remove and treat or dispose of contaminated soil from land	*Environmental Protection Act 1994*	DES
Development Permit for Operational Works for constructing or raising waterway barrier works	*Fisheries Act 1994 and Planning Act 2016*	Department of Agriculture and Fisheries (DAF)
Development approval for Operational Works for removal, destruction or damage to a marine plant	*Fisheries Act 1994 and Planning Act 2016*	DAF
Permit to get or sell forest products or quarry materials	*Forestry Act 1959 and Land Act 1994*	DAF

Legislative Requirement	*Relevant Legislation*	Administrator
Permit to occupy and clear vegetation on State Land	*Land Act 1994*	State Land Asset Management Unit within Department of Resources
Permit to take protected plants (clearing permit)	*Nature Conservation Act 1992 and Regulations*	DES
Petroleum Pipeline License (PPL)	*Petroleum and Gas (Safety and Production) Act 2004*	Department of Resources (DoR)
Development Permit to undertake development on a registered Queensland heritage place	*Queensland Heritage Act 1992 and Planning Act 2016*	DES
Approval to enter or interfere with a protected heritage area	*Queensland Heritage Act 1992*	DES
Development Permit for a Material Change of Use for gas transportation infrastructure	*State Development and Public Works Organisation Act 1971, Development Scheme for the Gladstone State Development Area*	Coordinator-General
Development Permit for a Material Change of Use for Materials Transportation and Services Infrastructure	*State Development and Public Works Organisation Act 1971, Development Scheme for the Stanwell-Gladstone Infrastructure Corridor State Development Area*	Coordinator-General
Owners Consent	*Planning Act 2016*	DES
Road Corridor Permit / Ancillary Works and Encroachment Permit	*Transport Infrastructure Act 1994*	Department of Transport and Main Roads (DTMR)
Traffic Control Permit	*Transport Infrastructure Act 1994*	DTMR
Written approval to interfere with a railway – Wayleave agreement	*Transport Infrastructure Act 1994*	DTMR
Development Permit for Operational Works for clearing native vegetation	*Vegetation Management Act 1999*	DES
Clearing Notification	*Vegetation Management Act 1999*	DES
Development Permit for Operational Works for taking or interfering with water for overland flow including using a watercourse pump, storing, diverting, damming or removing quarry material from a watercourse	*Water Act 2000 and Planning Act 2016*	Department of Regional Development, Manufacturing and Water (DRDMW)
Water Licence	*Water Act 2000*	DoR
Riverine Protection Permit	*Water Act 2000 and Regulations*	DRDMW
Local Approvals		

Legislative Requirement	*Relevant Legislation*	Administrator
Development Permit for a Material Change of Use for temporary worker accommodation camps under a Planning Scheme	*Relevant local government planning scheme, Planning Act 2016 and Planning Regulation 2017*	Relevant local Council
Development Permit for Operational Works under a Planning Scheme	*Relevant local government planning scheme, Planning Act 2016 and Planning Regulation 2017*	Relevant local Council
Development Permit to undertake development on a registered local heritage place	*Planning Act 2016 and Planning Regulation 2017*	Relevant local Council
Permits under Local Laws	*Local Government Act 2009*	Relevant local Council
Development Permit for Building Work	*Building Act 1975 and Regulations, Planning Act 2016 and Planning Regulation 2017*	Relevant local council or private building certifier
Temporary road closure – issue of road license	*Local Government Act 2009 (and other relevant acts e.g. Plumbing and Drainage Act 2002)*	Relevant local Council

10.3 Key approval considerations

As presented in Table 35, a number of approvals are required under Queensland and Commonwealth legislation before the construction and operation of petroleum and gas projects can commence.

Environmental and social risks associated with a project could delay delivery and present financial risks. Delays to the granting of approvals and permits can also result from either slow Government response times or from requests for additional information regarding likely project constraints. Legal challenges can also occur and delay time to securing approval.

Key approval considerations that have the potential to impact a project schedule, particularly for major petroleum and gas projects in Queensland, are outlined below.

10.3.1 Water

Work that may interfere with or impact on water courses, particularly within the bed and banks, would trigger the requirements of the *Water Act 2000* and, as necessary or desirable, would need to be discussed with the Department of Resources. Activities involving excavation, filling or the destruction of vegetation in a watercourse would require a riverine protection permit.

Additionally, proponents for a CSG or large mining project that are likely to have a significant impact on a water resource will need to refer the project to the Commonwealth to determine whether the project is considered a controlled action under section 68 of the EPBC Act.

The Significant Impact Guidelines 1.3: Coal seam gas and large coal mining developments – impacts on water resources state that an action is likely to have a significant impact on a water resource if there is a real or not remote chance or possibility that it will directly or indirectly result in a change to:

- The hydrology of a water resource; or
- The water quality of a water resource,
- That is of sufficient scale or intensity as to reduce the current or future utility of the water resource for third party users, including environmental and other public benefit outcomes, or to create a

material risk of such reduction in utility occurring. A significant impact on water resources may be caused by one development action relating to a CSG project or large coal mine, or the cumulative impact of such actions.

10.3.2 Land acquisition

Acquisition of land from a number of landholders would likely be required for the Bowen Basin Gas Pipeline project. This presents a risk as the Project may encounter opposition from landholders. Risks can be minimised through maintaining effective communication with Government representatives and affected landholders throughout the approvals process. Early submission of permit applications, compliance with Government requirements and effective stakeholder engagement would also assist in minimising permit risks. Commencement of the land acquisition process as early as possible is recommended.

Interference with landholder activities would also need to be investigated as part of an EIS. Each affected landholder would need to be consulted as part of the EIS/approvals process to discuss his/her specific requirements, establish compensation agreements and mitigate potential impacts to local land tenure.

10.3.3 Overlapping tenure

Almost 90% of Queensland's coal and coal seam gas tenure is overlapped, which in the past has led to an adversarial outcome to the benefit of no one. A revised framework for addressing overlapping tenure was incorporated into the *Mineral and Energy Resources (Common Provisions) Act 2014*.

The new overlapping tenure framework is a legislated default regime which applies where overlapping parties cannot otherwise agree. The framework seeks to optimise the safe development of Queensland's coal and coal seam gas resources by:

- Simplifying the pathway to and improving the certainty of the grant of overlapping tenure
- Incentivising negotiated arrangements for collaborative and cooperative concurrent production of both resources in overlapping areas
- Providing a default set of arrangements and dispute resolution processes to provide certainty to arrangements for coordination of activities if the parties cannot agree between themselves
- Providing a structure for joint coordination and management of health and safety
- Reducing administrative burdens, while preserving production rights already granted.

Overlapping tenure holders who are subject to the overlapping tenure regime in Chapter 4 of the *Mineral and Energy Resources (Common Provisions) Act 2014* are subject to mandatory requirements to exchange all information reasonably necessary to allow them to optimise the development and use of coal and CSG resources and to meet to discuss this information.

10.3.4 Coexistence issues

A simultaneous operations zone is an area where coal and CSG production activities can co-exist. A key feature of the revised overlapping tenure framework is the requirement for a joint interaction management plan (JIMP) in various overlapping operating scenarios.

In relation to the JIMP requirements under the respective safety legislation, the party responsible under that legislation to make a JIMP must make reasonable attempts to consult with the other party. The party responsible to make a JIMP must have regard to any reasonable provisions proposed by the other party(s) relating to the management of risks and hazards and either reach agreement about the content of the proposed JIMP or apply for arbitration.

10.3.5 Stakeholder engagement

The approvals process and project more broadly would involve liaising with a broad range of stakeholders, with a number of potential risks related to specific stakeholder types.

The complexity of identifying all traditional owners and other indigenous parties with interests in the lands that would be affected could be a major risk. A number of existing Native Title claims are likely to exist over the lands covered by the project. Additional indigenous groups with interests other than those who have made Native Title claims may appear and additional claims may be triggered as the project becomes more public. Therefore, Native Title negotiations would require careful planning early in the project to identify the best way to achieve successful land access outcomes and timely project approvals.

Other risks relate to engagement and communication with communities who would be affected by the influx of construction workers. Profiles of each community would need to be developed to identify the specific risks and issues each community may identify regarding the project.

Another stakeholder risk is from green group activism. Over recent times, green groups have been successful in disrupting, delaying and even preventing major energy and resource projects from proceeding through extensive social media campaigns and formal legal challenges. Legal challenges have been known to delay energy and resource projects for several years, and in some circumstances, have led to their ultimate refusal. Understanding and engaging with all key relevant stakeholders as early as possible in the project lifecycle is recommended.

10.3.6 Native title

Potential exists to impact upon lands, items or artefacts of indigenous significance. In addition, components of the project may impact Native Title and Cultural Heritage values. The project would require extensive engagement with indigenous groups, traditional owners and Native Title holders.

As part of the approvals process, the impact of the project on indigenous cultural heritage values would be undertaken. As part of the CHMP, an indigenous cultural heritage survey would be undertaken to identify significant Aboriginal objects and/or areas. The management of indigenous cultural heritage impacts would be detailed in either a Native Title agreement with traditional owners or a CHMP. The development of the Native Title agreements or CHMP would be negotiated with all relevant stakeholders' representatives. As a minimum requirement, the impact assessment management and protection strategies would need to satisfy the statutory responsibilities and duty of care under the *Aboriginal Cultural Heritage Act 2003* (Qld) and the *Aboriginal and Torres Strait Islander Cultural Heritage Protection Act 1984* (Cth).

10.3.7 Environmental constraints and offsets

Project infrastructure would be spread across a large geographical area, potentially consisting of rural and previously undisturbed land. Clearing of vegetation would likely be required for the project. Endangered and of concern regional ecosystems, endangered ecological communities, essential habitat and threatened plants are likely to be identified in some areas affected by the project. Therefore, the project does have potential to significantly impact on threatened species and ecosystems.

Offsetting of impacts to threatened species and ecological communities could be a costly and lengthy process requiring ongoing management throughout the life of the project and potentially beyond. Site selection, project planning and effective mitigation measures would minimise the risks associated with clearing of vegetation and associated offsetting requirements.

10.4 Fatal Flaws - Environmental No-Go Zones

A high-level desktop review of the possible corridor options has been undertaken and there have been several key areas of constraint identified as follows:

Moranbah to Rolleston

- Norwich Park Nature Refuge (MNES and MSES);
- Peak Range National Park (MNES and MSES); and
- German Creek Nature Refuge (MSES).

Moranbah to Gladstone

- Goodedulla National Park (MNES and MSES);
- Junee National Park (MNES);
- Great Barrier Reef Marine Park (MNES);
- Rainbow Mountain Nature Refuge (MSES);
- Bouldercombe Gorge Conservation Park and Resources Reserve (MSES); and
- Fitzroy River Fish Habitat Area A (MSES).

10.5 Recent EIS Trends

Based on a desktop review of recent EIS's prepared for major petroleum and gas projects in Queensland, a summary of trends is provided in Table 36. The table below provides a breakdown of recent EIS' prepared for similar projects, outlining the timing between EIS preparation, submission and approval, and any challenges identified.

Table 36 - Recent EIS Trends

(Source: GHD analysis)

Project / Proponent	EIS Approvals Trend
Arrow Bowen Pipeline Project **Arrow Energy Pty Ltd**	The Arrow Energy Pty Ltd 'Arrow Bowen Pipeline Project' involved the construction and operation of a buried high pressure coal seam gas transmission pipeline from approximately 90 km north of Moranbah, to approximately 22 km west of Gladstone (total length of approximately 580 km). Arrow prepared an EPBC Act Referral. The referral was submitted to the Commonwealth in July 2012 and was assessed by preliminary documentation. The referral was approved in October 2014 with conditions. The project was assessed by preliminary documentation as the only MNES impacted by the project was listed threatened species and communities. An Initial Advice Statement (IAS) was prepared describing the project and application for the preparation of a voluntary EIS and submitted to the Chief Executive of the former Department of Energy, Resources and Mining (DERM) (now Department of Resources). DERM assessed the application and notified Arrow in February 2011 of approval. Arrow prepared an EIS, which was submitted in February 2012 and approved by the Queensland Government approval in March 2013. The Moranbah to Gladstone option follows a similar route to the Arrow Bowen Pipeline Project and is likely to intersect similar MNES and MSES.

Project / Proponent	EIS Approvals Trend
Queensland Curtis LNG Project **Queensland Gas Company Ltd and BG International Ltd**	The Queensland Gas Company 'Queensland Curtis LNG Project' involved the expansion of current gas operations, construction of approximately 730 km network of gas pipelines, as well as an LNG plant and export facility. An EPBC Act Referral was prepared in June 2008, with the project being deemed a controlled action to be assessed by an EIS. An IAS was prepared and submitted in June 2008. and a bilateral EIS was prepared and submitted by October 2009. The project was then approved under a bilateral agreement under the EPBC Act with conditions in October 2010. The project was assessed under a bilateral EIS between Commonwealth and State as a result of the following: A portion of the pipeline was located between the mainland and Curtis Island, within the boundary of the Great Barrier Reef World Heritage Area/ National Heritage Place/Commonwealth marine area Impacts to listed threatened ecological communities, listed threatened species and migratory species
Australia Pacific LNG Project **Origin Energy and Conoco-Phillips**	The project involved the development of gas fields in the Surat Basin, alongside the construction and operation of a 450 km gas transmission pipeline and an LNG facility. An IAS was submitted, and the project was declared a significant project by the Queensland Coordinator-General, for which an EIS was required. An EPBC Act Referral was submitted in July 2009 to the Commonwealth and was determined a controlled action to be assessed by an EIS. The project was assessed under a bilateral EIS between Commonwealth and State as a result of the following: A portion of the pipeline was located between the mainland and Curtis Island, within the boundary of the Great Barrier Reef World Heritage Area/ National Heritage Place/Commonwealth marine area Impacts to listed threatened ecological communities, listed threatened species and migratory species The bilateral EIS was approved with conditions in February 2011.

11. The most likely scenario

11.1 The need

There is a confirmed need for the securing of additional domestic gas supplies to supplement demand by the mid-2020s, and the Bowen Basin is the prime candidate.

Forecasts consistently predict a shortfall of gas supplies into the ECGM by the mid-2020s, starting with peak demand periods (winter) and extending to net annual shortfalls. This will drive upwards pressure on domestic gas prices and downward pressure on consumption, and thus economic activity in gas-intensive industries.

As a result of the analysis undertaken as part of this Study, there is a there for the development of additional gas production capacity to supplement the predicted shortfall of gas in the ECGM.

Whilst other prospective basins exist and could also be developed to provide gas into the ECGM, the Bowen Basin is considered to be in prime position to supply this shortfall due to the level of existing infrastructure, existing production and extensive exploration and appraisal activity.

11.2 The supply scenario

It is economically achievable to unlock production from the Basin in volumes that will provide meaningful additional gas supplies to market. No one scenario is a clear stand-out, and it is possible that a combination of both production from Mahalo & Moranbah, with potential production from Blackwater, will all contribute to unlocking the Basin.

Based on assessment of global energy demand, a netback price point of approximately AU$7.00 to $7.50 / GJ at Wallumbilla has been calculated as part of this Study and is considered a reasonable middle-point for long term gas price for the ECGM, under balanced ECGM supply and demand conditions. Where supply is tight the ECGM prices will be elevated, with the GSOO predicating tight supply conditions to persist in the near to medium term. The economic viability of the Bowen Basin development has been based on this forecast ECGM gas price to provide a reasonable and realistic assessment of economic recovery.

Moranbah region

In the Moranbah region, a *target rate* of 170 TJ of gas per day was used. Modelling indicates that this target can be achieved with drilling and completing 319 wells over the ramp-up phase of development. The well count could include existing wells once prior volume commitments have been fulfilled. To continue the plateau of 170 TJ of gas per day, additional wells are drilled as needed over the next 15 to 20 years. It is assumed that 50 TJ of gas per day will be sent to the domestic market in Townsville, and the remaining 125 TJ of gas per day will be transported south via a new pipeline. It is noted that the Moranbah region has several areas available for development with higher production potential than represented with the high case type curve wells, however the production model has been kept purposefully conservative given the concept level of this Study.

Blackwater region

The Blackwater region has the least amount of CSG production and pilot data and is considered to have the highest risk of development. A *target* of 70 TJ/day was used. Modelling indicates that this target can be achieved with 205 wells drilled and completed starting in 2030. Additional wells are drilled and completed as needed to maintain the 70 TJ of gas per day *target* over the next 15 to 20 years. This delay allows for further delineation and data gathering in the Blackwater region and also provides time to establish a firm gas supply in the Moranbah and Mahalo regions to provide economic support for pipeline investment.

Mahalo region

In the Mahalo region, a *target rate* of 170 TJ of gas per day was used. Modelling indicates that this target can be achieved with drilling and completing 319 wells over the ramp-up phase of development. To continue the plateau of 170 TJ of gas per day, additional wells are drilled as needed over the next 15 to 20 years. There are existing wells in the Mahalo region that could contribute to the total gas volume if prior volume commitments are fulfilled. The majority of gas volumes from this scenario are available for a pipeline going to southern markets via the ECGM. Similar to the Moranbah region scenario, the Mahalo region also has an area of development that the high-side type curve well could exceed.

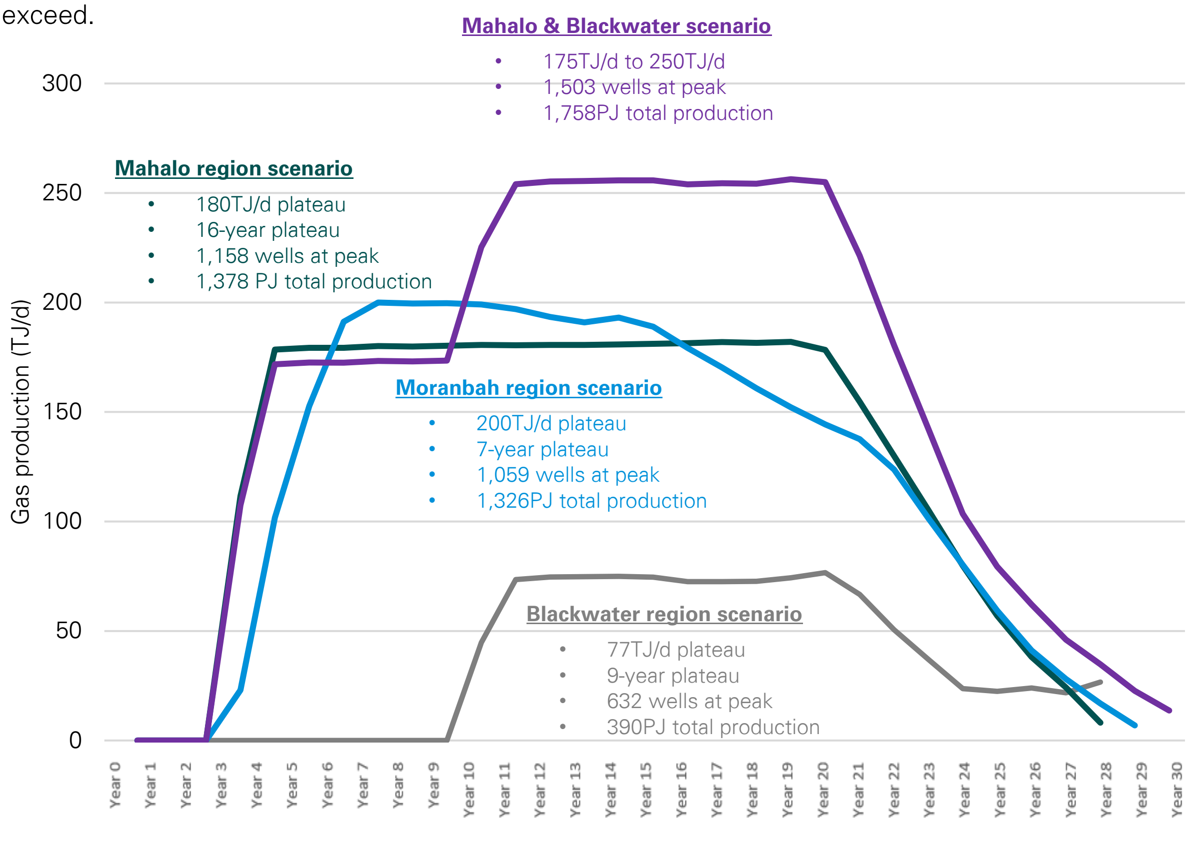


Figure 94 – Bowen Basin production profiles (mid-case) – all scenarios

(Source: NSAI Analysis)

**Note the graph represents modelled production which may differ from the target values.*

The production scenarios modelled, based on the inputs and assumptions developed through existing knowledge of the Bowen Basin, publicly available data and stakeholder feedback, result in a number of pathways to economically produce natural gas from multiple regions in the Basin. ***The estimated achievable production volumes would contribute meaningful additional gas supply to the ECGM over a significant period.***

The actual pathways to development may differ from these scenarios as technology improves, costs reduce, and further exploration and appraisal programs are prosecuted (particularly in the central region of the Bowen Basin between Moranbah and Blackwater). However, it is clear from the analysis conducted, that it is achievable to unlock production from the Basin in volumes that will provide meaningful additional gas supplies to the ECGM, consumers in North Queensland (particularly Moranbah and Townsville) and potentially to the Gladstone LNG plants for export to trading partners in Asia.

Notably, the analysis indicates that a larger play encompassing the Blackwater and Mahalo regions is needed to underwrite the development of the Basin. However, confidence in the reserves contained within the Blackwater region is limited due to low level of exploration that has occurred in this area.

Only supporting the smaller play of Moranbah to the north will not be enough to unlock the development of the whole Basin.

11.3 The role of coal mine methane

The reduction of emissions resulting from the capture and use of even a small portion of CMM far outweighs the cost of the additional new emissions from developing the basin's CSG reserves.

Analysis undertaken as part of this Study indicates that the development of the Basin is expected to generate total emissions below 10Mt CO2-et over the life of the project. Using this estimate, we can see that the 12 Mt total emissions from the basin development (high case in central scenario) would require only a 4% reduction in overall UG coal mine fugitive emissions to achieve emissions ROI (4% of mid case >300Mt unabated UG coal mine emissions).

However, currently, mine operators have been averse to either investing in new gas processing infrastructure or owning and operating that infrastructure. Generally, mine operators are supportive of power generation and moving surplus energy as “electrons” as opposed to “molecules”. The current business landscape therefore suggests that policy drivers, improvements to the regulatory frameworks and cross sector collaboration from both private and public sector players will be critical to the development of the Bowen Basin gas resources.

Strategies for improved future utilisation, and therefore enablement of production and beneficiation of CMM, are likely to be crafted around the following key focus areas:

- **Overlapping tenements**: New frame works for coal and CSG overlapping tenures must continue to strive for maximum flexibility for resource authority holders, inclusive of the ability for relevant parties to mutually agree on non-regulated arrangements that may fall outside legislative or default requirements.
- **Subsidisation:** Power station and/or other gas beneficiation facilities will have a greater chance of development through participation in emerging or potential future emissions subsidy schemes.
- **Transmission Networks:** Upgraded transmission system may encourage or enable larger power plants and drive common use infrastructure (e.g. gathering and transmission pipelines to centralised power plants).

- **Ventilation air methane:** Mines could be incentivised to reduce VAM from established baseline emissions through either emissions crediting or direct regulation.
- **New Markets:** New energy supply chains could be considered utilising either CSG and low-quality gas associated with its production or incidental mine gas that has been treated to suitable quality, although not necessarily pipeline specification gas.
- **Infrastructure:** Access to pipelines. One of the most significant barriers to utilising pre-drainage coal mine gas is access to export pipelines, due to the typical lack of proximal export pipelines, and the lack of required gas infrastructure to meet pipeline quality and pressure requirements. For these reasons, it is typically not economic to capture coal mine gas and export to the commercial market.
- **Gas Quality Requirements:** CMM is typically highly variable in quality and flow, hence it can be a challenge to deliver consistently economic gas to market at suitable quality.
- **Emerging Technology:** Developing and incorporating the use of emerging technology, such as membrane separation of methane to improve concentration to useable levels, has the potential to change the dynamics of the CMM utilisation in the Basin.

Traditionally, mine operators have been averse to either investing in new gas processing infrastructure or owning and operating that infrastructure. Generally, mine operators are supportive of power generation and moving surplus energy as "electrons" as opposed to "molecules". The current business landscape therefore suggests that policy drivers, improvements to the regulatory frameworks and cross sector collaboration from both private and public sector players will be critical to the development of the Bowen Basin gas resources.

11.4 Infrastructure requirements

Delivery of infrastructure is **the key enabler** to the development of the basin. However, the **optimal solution** may look substantially different to what different stakeholders may expect.

The analysis undertaken as part of this Study indicates that the existing infrastructure in the north is sufficient to cater for the expected demand with little supporting infrastructure required, however, with limited existing infrastructure in the central region, large gas reserves not connected to the ECGM and a new pipeline connection is warranted.

As detailed in Section 7, there are a number of pathways to economically produce natural gas from multiple regions in the Basin that would ultimately underpin the construction of a gas pipeline connection to the ECGM.

Whilst a new gas pipeline isn't the largest component of costs to develop the Bowen Basin, stakeholder reflections suggest that lack of infrastructure has been a key contributing factor to the delayed development of the Basin and will remain a key barrier into the future. Without the construction of a connecting pipeline to the ECGM, the Blackwater and Moranbah areas of the Basin are not likely to encourage investment and will not result in any material gas development occurring.

As outlined in Section 9, there are several likely options for pipeline routes that could connect the Blackwater and Moranbah regions to the ECGM:

- Routes developed as part of this Study: Option 1, 2a, 2b, 3; and
- Routes that have been proposed by industry.

A strategic merit test (SMT) was undertaken using the Government's objectives for the Basin as part of this Study of:

- Improving surface economic viability of gas production and providing gas to market to deliver shared benefits for the region and the State as a whole;
- Delivering efficient, multi-user gas transport infrastructure that will unlock gas resources;
- Enhanced commerciality of gas field developments in the Basin;
- Future-proofing gas supplies in Queensland; and
- Better management of incidental coal mine gas.

These findings are summarised as follows:

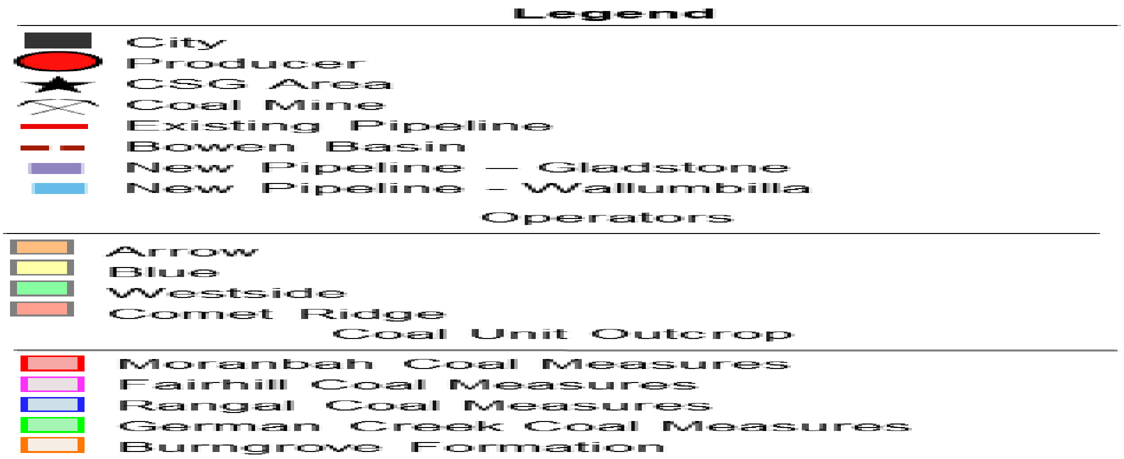


Figure 95 – Strategic Merit Test

Option 2B (refer Figure 96) supports a "whole of Basin" solution. The route enables a staged development of the pipeline, with the first stage a connection from the Mahalo region to Wallumbilla with a future extension to Moranbah. This staged approach has the benefit of supplying gas into the ECGM with less upfront capital investment required, creating confidence for industry to invest, whilst providing time for the certifying of sufficient reserves in the Blackwater region before a connection to Moranbah is constructed. Building a shorter pipeline initially, de-risks the pipeline investment, as it requires less upfront capital and is based on more well proven assets in the Mahalo region.

The first stage of the pipeline should be "oversized" such that it would not become a future bottleneck, however expansion is possible in the future using additional compression as well as initially oversizing the diameter. The first stage of the pipeline considering Mahalo only is likely to supply ~150 TJ/d. The second stage connecting Blackwater and Moranbah could contribute an additional 225 TJ/d, for a total of 375 TJ/d. Therefore sizing the initial pipeline for the future flow would require an approximately 22-inch pipeline instead of 16 inch for Mahalo only. The cost implication of this oversizing would be an additional 40% on the initial ~140km pipeline, or in the order of ~$64M. In terms of which option is best considering additional diameter vs compression, it is likely a lower investment risk to achieve additional capacity via compression rather than additional diameter. However, a more detailed assessment would be required to confirm this and would also depend on what options are offered by a pipeline proponent.

Option 2B also maximises the utility of methane from coal in the basin, from both mining operations and coal seam gas production as it provides the closest access to the majority of the prospective resource. However, further investigations into the constructability of the pipeline through mining operations and leases need to be undertaken.

With any pipeline asset development, the configuration and routing of the Bowen Basin pipeline will be dependent on which party or parties take the commercial risk to invest into the asset. Government and industry have differing priorities and objectives driving investment decisions. There are always trade-offs that occur within this, and for fully commercial entities the focus is on maximising the return and reducing the risks for an investment over a defined time period. Whereas governments have a different investment perspective and consider the broader economic benefit over a longer period of time, including direct and indirect benefits that include potential of growth in energy intensive downstream industry and regional growth.

A key role for Government in subsequent phases of the development of the Basin is to clearly articulate to industry their objectives for the development of the Basin and measures to help mitigate risks in the construction of the pipeline.

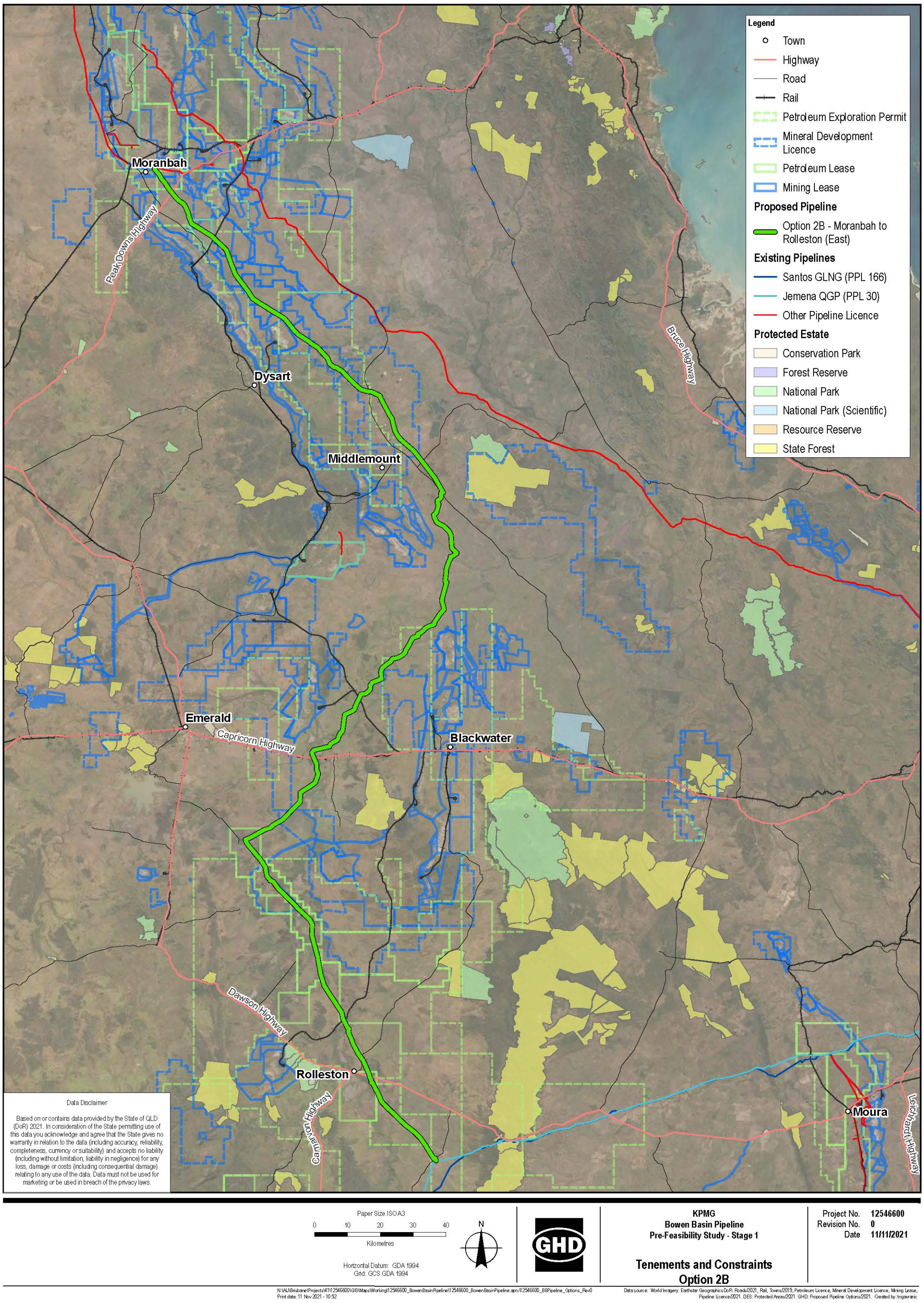


Figure 96 – Option 2B

(Source: GHD analysis)

11.5 Timing considerations

Timing is critical for the development of the Basin, with many drivers influencing timelines

Getting the timing right for the development of the Basin will largely determine the resulting benefits to Queensland. If the Basin is development is too fast, it may suit industry but not be in the best interests of the State. If the development is too slow, other Basins such as the Beetaloo in the Northern Territory may overtake and erode some of Queensland's benefits.

There are many factors that need to be considered in timing implications, however an overriding factor is the forecast supply shortage in the ECGM. Given this, and the relative timing and potential volume of gas when compared to other prospective basins that could supply Eastern Australia, the Bowen Basin has an import role to play in the medium-term energy security of Australia.

As described above, there is an anticipated need for additional gas into the ECGM by the mid-2020s, and the Bowen Basin is well positioned to provide a portion of the forecast shortfall. This implies that for a pipeline to be able to supply the market, the pipeline development would likely need to have FID within 24 months' time. Additionally, there would need to have been sufficient development of reserves such that there is sufficient confidence that a pipeline investment is warranted from an economic benefit perspective.

The analysis undertaken as part of this Study indicates that the *'best case'* timeline for a material increase in gas production in the Basin is approximately 5 years, comprising of the following elements:

Project establishment and market conditions for commencement of development - **unknown**

Exploration and appraisal to firm up sufficient resource – **anticipate 2 years or longer**

Gas plant – typical duration for approvals, engineering, procurement and construction **– 2 to 3 years**

Pipeline - typical duration for approvals, engineering, procurement and construction **– 3 years**

No major issues with existing support infrastructure to enable development - **no material impact to timelines**

Figure 97 – Basin development timeline (best case scenario)

However, historical basin development and industry feedback indicate that the *most likely* timeframe for development of the Basin is 7 years. Government has an important role to play in creating confidence for industry to invest and navigating the competing timeline priorities. Triggers are available that could accelerate the development of the Basin such as championing the development of the Basin through the establishment of governance frameworks to enable better collaboration between all tiers of Government and industry and streamlining approval pathways.

11.6 Identified challenges and opportunities

Developing the Bowen Basin will be complex and challenging but it has the opportunity to improve Queensland's productivity, liveability and environmental sustainability

As with the development of any gas basin, many challenges and opportunities are present. However, the analysis undertaken as part of this Study is that there is a clear need for the securing of additional domestic gas supplies and Queensland is in the optimal position to leverage that opportunity with the development of the Bowen Basin. Key to maximising the benefits to Queensland will be converting the challenges to opportunities.

Figure 99 highlights the key challenges and opportunities for the development of the Basin as part of this Study. As noted, development of the Basin can improve the prosperity of Queensland, most notably the regions. The supply of affordable gas is expected to stimulate industrial development, particularly in the northern regions such as Townsville. This will have flow on effects through to jobs and economic growth for the next generation.

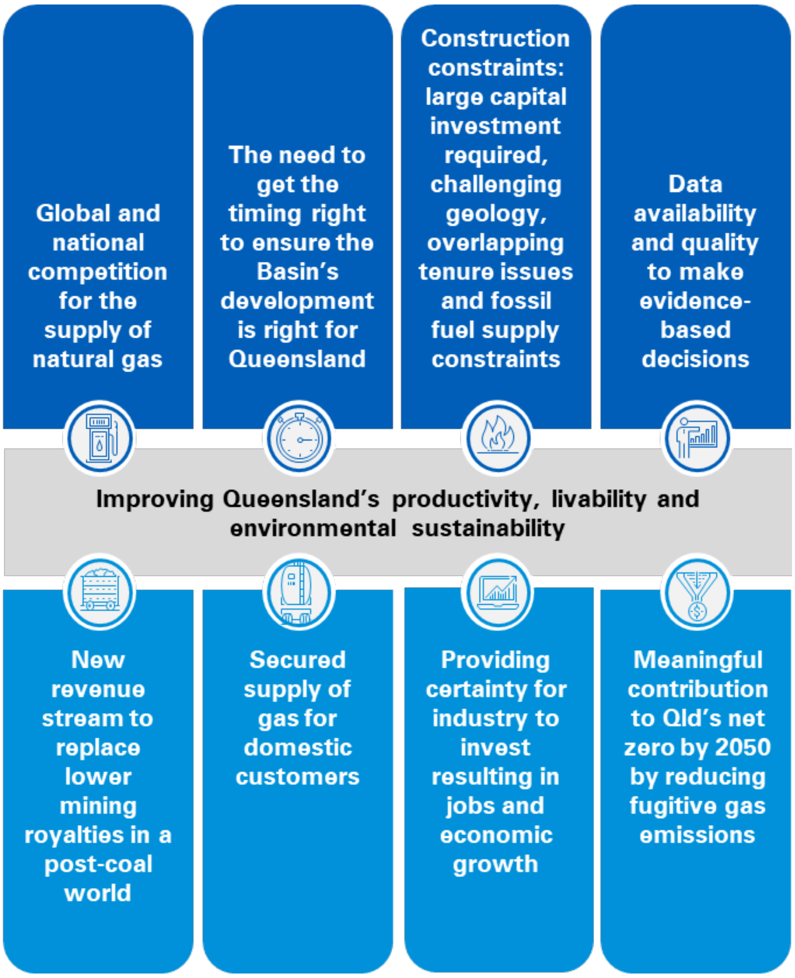


Figure 98 – Key challenges and opportunities

However, the key barriers that need to be overcome include:

A need to change the current state of play

- There is a need to increase the appetite to invest for incumbent players
- Creating a diverse and strong consumer demand for the gas for industry to underwriting a large-scale development of upstream CSG reserves.

The Bowen is technically challenging

- Evidence from existing production and exploration wells demonstrate that the Bowen Basin coals have lower permeability, are located deeper and are higher pressure than the Surat Basin coals.
- May require the use of enhanced recovery techniques such as hydraulic fracturing, which brings with it a range of technical, social and environmental risks.
- Wells also need to target specific coal seam measures to ensure productivity.
- Sufficient reserves need to be certified in a timely manner.

Navigating a complex stakeholder landscape

- The Bowen Basin coal measures are shallower on the Eastern and Western flanks – these measures are the ones that are being extracted by Queensland's large coal mining industry.
- Beyond 800m depth, it is difficult to economically extract CSG – meaning that CSG development in the Bowen Basin will require strong cooperation between CSG proponents and coal miners.
- Overlapping Tenure on the same acreage is possible and presents immense opportunity to capture coal mine fugitive gas emission, but also introduces complexity.

12. The role of Government

As discussed in Section 11, further unlocking of the Bowen Basin is considered economically feasible and has a clear role to play in securing domestic gas supplies. However, Government, across all levels, will need to play a pivotal role in facilitating the development of the Basin if it is to maximise its benefits for all Queenslanders.

12.1 Planning and policy

12.1.1 Existing policy guiding the Bowen Basin

Policy, across all tiers of government (Commonwealth, State and Local), outlines the Government's strategic direction and goals to enable effective use and the coordination of resources. Typically, Government promotes a desired future state which is delivered through planning, infrastructure and development.

Key planning and policy documents with tangible outcomes relevant to the Bowen Basin include:

- Australian Government's Gas-Fired Recovery;
- National Gas Infrastructure Plan: Interim Report;
- Our North, Our Future: 2021-26;
- ACCC's Gas Inquiry 2017-2025 – 2021 Interim Report;
- Gas Pipeline Decision Regulation Impact Statement (DRIS);
- The North Bowen and Galilee Strategic Basin Plan;
- Queensland's COVID-19 Economic Recovery Plan;
- Queensland Draft State Infrastructure Strategy;
- Queensland Climate Transition Strategy;
- Queensland Climate Action Plan;
- Queensland Renewable Energy Zones; and
- Regional Plans: Central Queensland and Mackay, Isaac and Whitsunday.

Appendix B provides details on key planning and policy initiatives relevant to the development of the Bowen Bain.

Working across numerous Government portfolios, these documents must be taken into consideration in order to sustainably develop the Bowen Basin whilst maximising the benefits it brings.

12.1.2 Previous and current policy interventions

The regulatory and policy environment remains dynamic, with continuous policy reform being driven by a variety of Government levels and different agencies within each level. Following significant policy measures implemented in the wake of the 2016 gas price spikes, as illustrated in Figure 99, the policy space has remained fluid with many different reform projects proposed and with significant focus from political leaders around gas market reforms, especially in the context of a gas-fired economic recovery following the initial COVID-19 pandemic lockdowns.

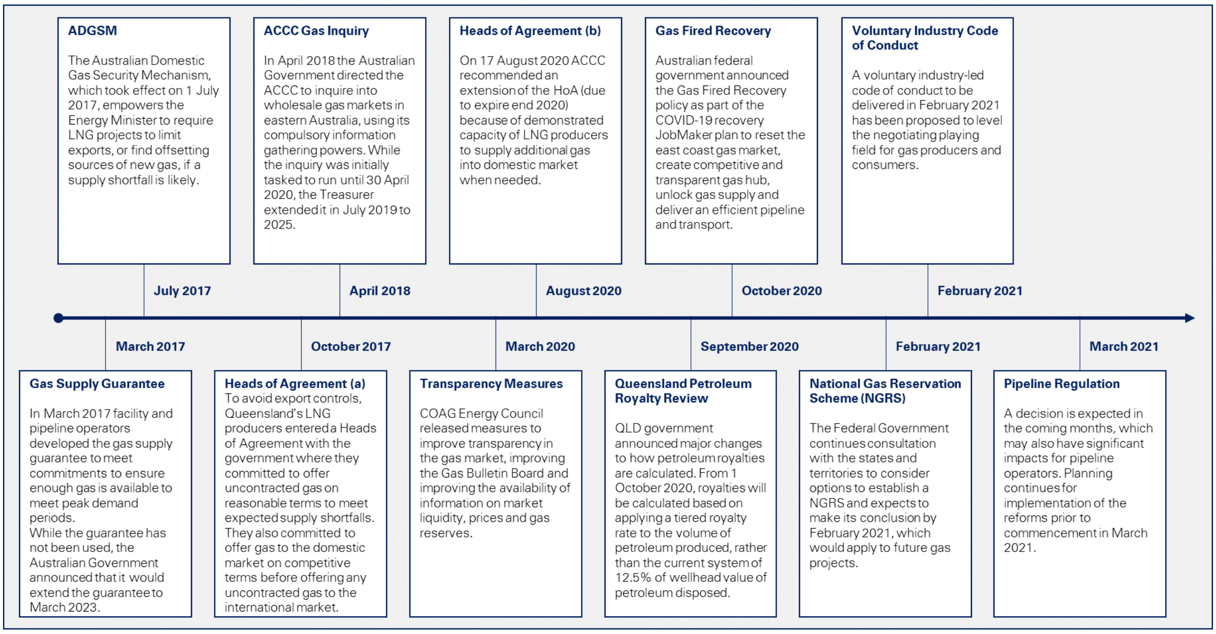


Figure 99 Timeline of Government policy initiatives in the ECGM

(Source: KPMG analysis)

Refer to Appendix F for details on recent policy reform measures impacting the ECGM.

Looking ahead, current policy reforms focused on increased price and volume transparency, improved liquidity, greater accessibility to transportation, domestic reservations and marketing behaviours should be considered.

12.2 Understanding industry challenges

Understanding industry's varied perspectives on the development of the Bowen Basin and the policies and strategies that underpin it, is critical to ensure that the Basin is developed in a way that maximises the benefits for all Queenslanders.

Table 37 identifies six key themes presenting challenges currently faced by proponents developing within the Basin. Although the challenges are impacting each proponent at varying levels, they all have the common feature of impacting investment decision within the Basin. These insights were informed through comprehensive industry engagement undertaken as part of this Study.

Table 37 Key industry challenges

Theme	Key challenges
Access to market	Lack of transmission infrastructure
Access to finance	High capital cost barriers to entry due to technical challenges Access to finance for smaller operators as lenders are increasingly moving away from divesting in fossil fuels Commercial regulation risk
Demand in the North	Access to finance for gas customers due to unconfirmed gas supplies Single customer demand increasing commercial risk for gas suppliers to invest
Approval processes	Land access arbitration Thresholds for pipeline approvals for frontier basins State/Federal Government approval complexity Increasing cost of approval processes
Coal/gas stakeholder interface	Perception of primacy of coal in the Basin (over gas) Negotiation complexity for overlapping tenure Low level of formal collaboration forums Perceptions of fugitive emission value
Confidence in reserves	Low quality/quantity of data in central region

When considering the role of Government in facilitating the development of the Basin, numerous levers could be considered to help mitigate the above identified challenges and lessons learnt. Potential areas of consideration are discussed in Section 12.3 below.

Leveraging lessons from the development of the Surat

In addition to the above, there are several key lessons learnt from the development of the Surat that should be considered when facilitating the development of the Bowen Basin (in the context of the scale differences expected):

- **Broad stakeholder engagement** – A process that ensures broad stakeholder engagement from the industry and not just an individual project developer would enable greater level of collaboration, insight and facilitation of issue resolution.

- **Encourage high-level participation of regional labour** – An opportunity exists to proactively utilise local skilled labour in favour of fly-in fly-out resources. There is a potential opportunity to utilise skilled labour from the coal mining industry in the coal seam gas, which may assist in increasing the understanding of gas companies to work with the mining companies more effectively in utilisation of coal mine gas.

- **Increase focus on common use assets** – The development of a process to encourage project participants to increase collaboration around common use assets and resources in both the development stage and operations stage of the gas projects. Whilst this takes more coordination, it should go some way to supporting more cost-effective outcomes and improving stakeholder perceptions of the industry as a whole.

- **Sharing of lessons learnt** – Forums where industry participants and key stakeholders could share lessons learnt for the future benefit of the industry would provide a valuable approach that could minimise challenges, improve safety, and create improved stakeholder relationships.

12.3 Potential pathways to facilitate development of the Bowen Basin

12.3.1 The need for a strategic approach

As discussed in Section 4, the global energy market is in transition – over the past twelve months governments around the world have pulled economic levers to force transition away from polluting fuels. The Queensland Government, with an economy traditionally centred on mining, has also set a vision of a zero net emissions future that supports jobs, industries, communities and our environment which includes the commitments of:

- Zero net emissions by 2050;
- An interim target of at least 30% below 2005 levels by 2030; and
- Powering Queensland with 50% renewable energy by 2030.

This rapid domestic and global change is expected to see Queensland's traditional mining economic base narrow. This is already creating an atmosphere of uncertainty for industry to invest and for communities to prosper.

However, as discussed in Section 4, gas is an important transition fuel and demand for its gas is expected to be strong during this transition period and beyond. The development of the Bowen Basin is therefore expected to:

- Stabilise domestic gas prices;
- Provide certainty for industry to invest;
- Secure future royalties in a low carbon economy; and
- Deliver significant regional development opportunities for communities through investment into regional supply chains, regional service hubs and direct employment opportunities.

The development of the Bowen Basin will impact and provide benefits across all tiers of Government and many portfolios and this study has demonstrated the criticality of pipeline infrastructure to the further unlocking of the Basin.

However, the unlocking of the Basin cannot be delivered by Government alone, industry must play their part.

To strengthen the region's economy and instil confidence for industry to invest, an agreed narrative on how Queensland will navigate the energy transition combined with a strategic approach to planning and investment across all tiers of Government and industry will be required. This approach will ensure that the that the benefits of individual initiatives across portfolios and industry will be maximised.

Benefits of a partnering approach

- Shared understanding on planning and economic development priorities
- Alignment between all tiers of government creating private sector confidence in partnership and investment
- A commitment to Basin development priorities and delivery horizons
- A focus on transparent, outcomes focused decision-making, investment and policy
- Opportunities to leverage aligned co-investment by all three tries of government and the private sector
- An agreed program of infrastructure and investments

12.3.2 Focus areas

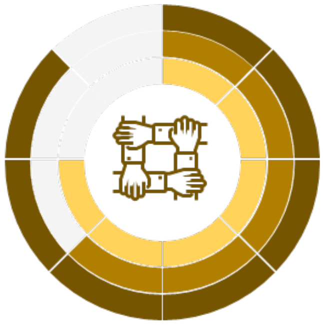
To facilitate the development of the Bowen Basin to the benefit of all Queenslanders, and in response to stakeholder challenges, three key focus areas for Government are starting to emerge:

Enabling Infrastructure

Facilitating the construction of common infrastructure to enable access to market, delivering affordable gas supplies, increasing competition, building international competitiveness and attracting private investment.

Supporting Zero Net Emissions by 2050

Leading by example in reducing fugitive emissions, investing in exploration activities and technology to improve the scientific understanding of geosciences data needed by industry.



Growing our Regions

Strengthening the regions economy by supporting ongoing jobs across supply chains, industries, investing in skills for the development of next generation of workers and creating new economic opportunities through diversification of the regions economic base. Improving the resilience of our regions through investment in community infrastructure.

Figure 100 – Focus areas

Source: KPMG analysis

These focus areas straddle numerous portfolios across all tiers of Government, with numerous initiatives already underway that will inform and influence the development of the Basin.

In addition to the policy actions and initiatives already underway, Table 38 outlines considerations for the role of Government in the development of the Bowen Basin. Adoption of these roles is expected to enable the Government to be an informed leader in the development of the Basin, future proof the regions, mitigate risks and create confidence for industry to invest in the Basin. However, in this rapid transition to a clean growth economy, it is critical that Government remains flexible to the changing needs of Queenslanders and industry.

Table 38 – Potential roles for Government

Role for Government	Description	Enabling Infrastructure	Supporting Zero Net Emissions	Growing our Regions
Ensuring alignment with contextual policy settings	Implementing policy actions from policy's and strategy's such as the Climate Action Plan, State Infrastructure Strategy, Regional Infrastructure Plans, Queensland Resource Industry Development Plan. Development of a Bowen Basin Strategic Plan	✓	✓	✓
Governance	Forums and frameworks to promote collaboration, share lessons learnt, enable timely decisions, and help navigate state and Commonwealth Government approval complexity	✓		
Enabling Infrastructure	Facilitating industry to provide access to market. This study has confirmed the criticality of pipeline infrastructure.	✓	✓	✓
Training and workforce development	Enabling the regions to invest in skills of the next generation of workers and provide opportunities along the supply chain.		✓	✓
Investment attraction and promotion	Encourage a diverse mix of suppliers and customers to de-risk upstream and midstream investment, creating confidence for industry to invest.	✓	✓	✓
Investment risk mitigation	Facilitate further investigation in the Basin and adoption of new technology to develop confidence in reserves and flow rates.	✓		✓
Open-source data publication	Enable Government to be an active participant through independent data collection, improving the perception of the value of incidental coal mine methane gas	✓	✓	

13. Next Steps

Embracing the development of the Bowen Basin is expected to help drive Queensland's economic recovery whilst transitioning to a low carbon, clean growth economy

There is clear potential for the Bowen Basin to be developed as a new upstream source of gas that, if connected to the ECGM, would help contribute to closing the projected gas supply-demand gap in Eastern Australia, forecasted to start in the mid-2020s. The development of the Bowen Basin will impact and provide benefits across all tiers of Government and many portfolios and this Study has demonstrated the criticality of pipeline infrastructure to the further unlocking of the Basin. However, the unlocking of the Basin cannot be delivered by Government alone, industry must play their part.

Therefore, it is recommended that the proposed next step for the Bowen Basin is to undertake a Structured Market Engagement process with potential pipeline developers and other identified stakeholders.

Structured Market Engagement Process

To encourage industry participation and create confidence for industry to invest, both the Commonwealth and Queensland Governments must be an informed leader in the development of the Basin. Key to testing and refining the role of Government in unlocking the Bowen Basin is a structured Market Engagement Process with likely market participants and other identified stakeholders.

Key elements of the process could include:

- **Identification of market participants:** Confirm market participants and key stakeholders to ensure equal opportunity to all.
- **Refining the potential role for government:** Build upon the current understanding from the market to clearly identify where Government may best play a role in the short to medium term supporting industry.
- **Testing potential government processes:** Test and refine, through market feedback and collaboration with DISER, a commercial model and process for potential Government support (financial and/or in-kind) and roles and responsibilities to support collaborative feasibility development.
- **Identifying key thresholds:** Identify, in consultation with market participants, key hold points and thresholds that would need to be satisfied for investment decisions.
- **Establishing indicative timetables and cost of development:** Establish, in consultation with market participants, a reasonable timetable, indicative cost for feasibility development and key milestones therein.

This Study has identified several market participants and some of their drivers. The Structured Market Engagement process will build upon this knowledge and would incorporate the more traditional next step of a feasibility study by building an understanding of the commerciality of the pipeline from the market's perspective. This approach is anticipated to improve private sector confidence in the establishment of the Basin, resulting in in significant time savings through:

- A shared understanding on planning and economic development priorities;
- A commitment to Basin development priorities and delivery horizons;
- A focus on transparent, outcomes focused decision-making, investment and policy; and
- Identification of opportunities to leverage aligned co-investment by all three tries of government and the private sector.

Appendix A: Glossary

Acronyms/initialisms

ACCC	Australian competition and consumer commission
ACQ	annual contract quantity
C&I	commercial and industrial
CFC	chlorofluorocarbon
CTP	capacity trading platform
CSG	coal seam gas
DTS	Declared transmission system
E&P	exploration and production [companies]
FEED	front end engineering and design
FID	final investment decision
GHG	greenhouse gas
GEMS	Greenhouse Energy Minimum Standards
GPG	gas powered generation/generator
GSA	gas supply agreement
GSOO	AEMO's Gas Statement of Opportunities
GSSA	Gas Storage Service Agreement
GTA	gas transportation agreement
GWP	global warming potential
MACC	marginal abatement cost curve
MDQ	maximum daily quantity
MOU	memorandum of understanding
NEM	National Electricity Market
NGL	National Gas Law
NGR	National Gas Rules
RTO	regenerative thermal oxidation
SPAs	sale and purchase agreements
STTM	short-term trading market
VAM	ventilation air methane
WAP	weighted average price
WORM	Western Outer Ring Main

SIS	Surface-in Seam
UGS	underground gas storage
2C	Contingent resources
2P	proved and probable reserves

Units

PJ	petajoules	(1 PJ = 1 thousand TJ = 1 million GJ)
TJ	terajoule	(1 TJ = 1 thousand GJ)
GJ	gigajoule	(1 GJ = 1 thousand MJ)
Btu	British Thermal Units	
Mt	million tonnes	
MW	megawatts	
MTPA	million tonnes per annum	
CO2-e	carbon dioxide equivalent	

Queensland licenses/terminology

ATP	authority to prospect
PCA	potential commercial area
PL	petroleum lease
PPL	petroleum pipeline licence

Industry bodies

AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
APPEA	Australian Petroleum Production and Exploration Association
GMRG	Gas Market Reform Group

Queensland gas projects/fields/wells

APLNG	Australia Pacific LNG
GLNG	Gladstone LNG
MGP	Moranbah Gas Project
QGC	QGC LNG

Queensland gas pipelines

CGP	Carpentaria Gas Pipeline	(Mt Isa to Ballera)
DDP	Darling Downs Pipeline	
EGP	Eastern Gas Pipeline	
GMP	Galilee Moranbah Pipeline	
GTP	Mainland Gas Transmission Pipeline	(Fairview to Curtis Island/Gladstone)
NQGP	North Queensland Gas Pipeline	(Moranbah to Townsville)
NGP	Northern Gas Pipeline	(Tennant Creek NT to Mt Isa QLD)
QGP	Queensland Gas Pipeline	(Wallumbilla to Gladstone and Rockhampton)
RBP	Roma to Brisbane Pipeline	
SWQP	South West Queensland Pipeline	
WGP	Wallumbilla Gladstone Pipeline	

Gas Hubs

WSH	Wallumbilla Supply Hub
MSH	Moranbah Supply Hub

Definitions

Term	Definition
2C contingent resources	Best estimate of contingent resources – equivalent to 2P reserves, except for one or more contingencies or uncertainties currently impacting the likelihood of development. Can move to 2P classification once the contingencies are resolved.
2P reserves	The sum of proved and probable estimates of gas reserves. The best estimate of commercially recoverable reserves, often used as the basis for reports to share markets, gas contracts, and project economic justification
Anticipated supply	Considers gas supply from undeveloped reserves or contingent resources that producers forecast to be available as part of their best production estimates provided to AEMO
basin	A geological formation that may contain coal, gas, and oil.
coal seam gas (CSG)	Gas found in coal seams that cannot be economically produced using conventional oil and gas industry techniques. Also referred to in other industry sources as coal seam methane (CSM) or coal bed methane (CBM).
Committed supply	Considers developments or projects which have successfully passed a financial investment decision (FID), and are progressing through the engineering, procurement, and construction (EPC) phase, but are not currently operational.
consumption	The measure of gas usage over time, typically one year. When forecasting, the consumption represents the total demand for energy over the given period.

Term	Definition
contingent resources	Gas resources that are known but currently considered uncommercial based on one or more uncertainties (contingencies) such as commercial viability, quantities of gas, technical issues, or environmental approvals.
conventional gas	Gas that is produced using conventional or traditional oil and gas industry practices.
demand	Capacity or gas flow on an hourly or daily basis, or the electrical power requirement met by generating units.
developed reserves	Gas supply from existing wells.
domestic gas	Gas that is used within Australia for residences, businesses, power generators, etc. This excludes gas demand for LNG exports.
gas-powered generation (GPG)	The generation of electricity using gas as a fuel for turbines, boilers, or engines.
global warming potential (GWP)	A measure of how much energy the emissions of 1 ton of a gas will absorb over 100 years, relative to the emissions of 1 ton of CO2. The larger the GWP, the more that a given gas warms the Earth compared to CO2. GWPs provide a common unit of measure, which allows analysts to add up emissions estimates of different gases and allows policymakers to compare emissions reduction opportunities across sectors and gases.
probable reserves	Estimated quantities of gas that have a reasonable probability of being produced under existing economic and operating conditions. Proved-plus-probable reserves added together make up 2P reserves
production	In the context of defining gas reserves, gas that has already been recovered and produced
prospective resources	Gas volumes estimated to be recoverable from a prospective reservoir that has not yet been drilled. These estimates are therefore based on less direct evidence than other categories.
proved and probable	See 2P reserves
reserves	Reserves are quantities of gas which are anticipated to be commercially recovered from known accumulations.
reservoir	In geology, a naturally occurring storage area that traps and holds oil and/or gas. Iona Underground Storage (UGS) is also referred to as a reservoir for gas storage.
resources	More uncertain and less commercially viable than reserves. See contingent resources and prospective resources.
undeveloped reserves	Gas supply from wells yet to be drilled.

Appendix B: Planning and Policy

Australian Government's Gas-Fired Recovery[14]

To assist in Australia's economic recovery from the COVID-19 pandemic, on 15 September 2020 the Australian Government announced the Gas-Fired Recovery as part of the JobMaker plan.

The 2021-22 Federal Budget allocates $58.6m over four years to support Australia's gas-fired recovery.[15,16] Of that amount, $38.7m is allocated to support critical gas infrastructure projects to help alleviate the potential gas shortfall on Australia's east coast. $5m has been allocated for this Concept Study.[17] Table 39 presents the measures outlined in both the September media release and 2021-22 Budget.

Table 39: Gas-fired recovery measures relevant to Queensland
(Source: KPMG Analysis)

Key Area	Initiative	Cost
Unlocking gas supply	New gas supply targets with states/territories and enforcement of gas license "use-it or lose-it" requirements	
	Strategic Basin Plans to unlock five key gas basins starting with the Beetaloo (NT) and North Bowen (QLD) basins	$28.3m for plans ($5m for Bowen)
	Funding for gas industry field appraisal trials in the North Bowen and Galilee Basins	$15.7m
	New agreements with the three east coast LNG exporters to avoid any gas supply shortfall – Heads of Agreement 2020	
	Support for CSIRO's Gas Industry Social & Environmental Research Alliance	$13.7m
	Exploring options for a prospective gas reservation scheme.	
Delivering an efficient pipeline and transport market	Identification of priority pipelines and critical infrastructure as part of an inaugural National Gas Infrastructure Plan (NGIP)	$5.6 for the final plan
	Future Gas Infrastructure Investment Framework to support consideration of critical gas projects identified by future NGIPs	$3.5m
	Reform of pipeline infrastructure regulation	
	Development of a dynamic secondary pipeline capacity market	
Empowering gas customers	Establish an Australian Gas Hub at Wallumbilla (QLD)	$6.2m
	Voluntary industry-led code of conduct	
	Review the calculation of the LNG netback price, with the ACCC	
	Use the NGIP to develop customer hubs or a book-build program for a more transparent and competitive process	

Source: (Morrison, 2020), (Taylor, 2021) & (Pitt, 2011)

Unlocking the North Bowen and Galilee: The Strategic Basin Plan[18]

As part of the Gas-Fired Recovery, the Australian Government identified the North Bowen and Galilee Basins as one of five strategic basin areas. To further operationalise the programs and priorities canvassed in the Gas-Fired Recovery, the Australian Government has released a Strategic Basin Plan

14 (Morrison, 2020)
15 (Australian Government, 2021)
16 (Australian Government, 2021)
17 (Taylor, 2021)
18 (Australian Government, 2021)

for the North Bowen and Galilee Basins. This plan allocates $20.7m of direct investment, as well as leveraging over $400m in research and infrastructure upgrades.

The Plan outlines a vision for the basins: "Creating jobs and driving economic growth by unlocking the full potential of the North Bowen and Galilee basins". It identifies immediate actions that the Australian Government will progress to contribute to realising this vision, as well as next steps which will be informed by data gathered by the immediate actions. One of these immediate initiatives is to model a possible future gas pipeline, which is explored in this Concept Study. These initiatives are detailed in Table 40.

Table 40: North Bowen and Galilee Strategic Basin Plan initiatives

Initiative	Total Cost	Timing
Immediate actions		
Gas well trials to crack complex geological challenges and establish cost-effective gas flows across four sites within the basins.	$15.7m	2021-22
Pipeline preparations to establish an optimal route and capacity for a possible future gas pipeline and understand the regional benefits of this work.	$5m (co-commitment with QLD Government)	2021-23
Funding for Geoscience Australia and the CSIRO to establish environmental evidence to support regulatory processes across strategic basins, including the North Bowen and Galilee.	$14m	2021-24
Funding to continue the CSIRO's GISERA research in these basins and across Australia.	$13.7m	2021-24
Road upgrades throughout the region which will support supply chains, trade and project construction across multiple sectors.	$370m	2021-onwards
Next Steps		
Together with the Queensland Government, consideration of the outcomes from gas well trials and pipeline preparations to support the development of the National Gas Infrastructure Plan.		2023-onwards
Prioritisation of regulatory applications by Commonwealth regulators to reduce costs that may otherwise cause lengthy delays.		2022-onwards
Strengthened training and education opportunities to ensure workers in the region have the skills to support gas projects.		2024-onwards
Working with governments to realise opportunities for gas to help unlock downstream and manufacturing opportunities in central and northern Queensland.		2024-onwards

Source: (Australian Government, 2021)

National Gas Infrastructure Plan: Interim Report[19]

In May 2021, the Department of Industry, Science, Energy and Resources published an interim report ahead of the full National Gas Infrastructure Plan. It forecasts medium-term gas supply shortfalls and lays out a blueprint up until 2027 that identifies the highest priority infrastructure investments needed to address the threat of shortfall and ensure continued reliable and affordable gas supply.

The Interim Report identifies four critical infrastructure projects to address the forecast gas shortfall:

- two gas storage projects at Golden Beach and Iona in Victoria
- expansion of the South West Victorian pipeline

[19] (Department of Industry, Science, Energy & Resources, 2021)

- a new import terminal (the Port Kembla, NSW project is at the most advanced planning stage).

The Interim Report assumes that 33 PJ of new supply can be made available to domestic customers if required by LNG producers. It however does not include 'discovery fields' including the Beetaloo and North Bowen basins at this stage.

When released, the full Plan will present a blueprint for the development of the east coast gas market out to 2040, which encompasses the planned actions to unlock the five strategic basins identified in the Gas-Fired Recovery (including the North Bowen Basin). The Plan will effectively form an analogue to AEMO's Integrated System Plan, for the gas sector instead of the electricity sector.

Our North, Our Future: 2021-26[20,21]

Delivered as part of the 20-year framework in the 2015 *Our North, Our Future: White Paper on Developing Northern Australia*, the next five-year plan for Northern Australia was announced in May 2021 and will be released later in 2021. It aims to bolster and support the Gas-Fired Recovery.

The 2021-22 Federal Budget allocates $189.6m over five years, which includes funding for a $111.9m Northern Australia Development Program that provides co-investment funding and advice to businesses. This may be relevant in the commercial development of the North Bowen Basin.

ACCC's Gas Inquiry 2017-2025 – 2021 Interim Report[22]

The 2021 Interim Report confirmed that forecast supply is expected to meet domestic and export demand in 2021 for the east coast gas market. However, it forecasts a supply shortfall from 2P resources from 2026, or as early as in 2024 for the southern states without the development of speculative resources or an LNG regasification terminal.

To address medium-term shortfalls, pipeline transportation or an LNG import terminal are warranted. To address long-term shortfalls (2028 onwards), Narrabri, the northern Bowen Basin and the Galilee Basin are all promising options to bring online.

The Report maintains that pipeline operators are still engaging in monopoly pricing that consumers ultimately pay for. The ACCC first made this assertion in April 2016 in its *Inquiry Into The East Coast Gas Market*.

It also notes that as of 30 June 2020, Queensland's Surat and Bowen basins held 30,520 PJ of 2P reserves, and that the three Queensland LNG producers either directly or indirectly control over 80% of Queensland's 2P (proven and probable) reserves and over 50% of 2C (contingent) resources.

Gas Pipeline Decision Regulation Impact Statement (DRIS)[23,24]

On 3 May 2021, the Federal Energy Ministers[25] announced reforms to improve the gas pipeline regulatory framework and address monopoly pricing by pipeline operators.

The recommended option was Option 3B which provides for the regulation of <u>all</u> pipelines, with two tiers: a stronger form of regulation and a lighter form for new (greenfield) pipelines which can obtain an exemption. This option expands the status quo/current scope of pipeline regulation in which only some pipelines are regulated ('scheme'). It also requires all pipelines to now provide third party access, and

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[20] (Department of Industry, Science, Energy & Resources, 2021)
[21] (Australian Government, 2021)
[22] (Australian Competition & Consumer Commission, 2021)
[23] (Energy Ministers, 2021)
[24] (Taylor, 2021)
[25] Minister for Energy and Emissions Reduction, Minister for Resources and Water, Minister for Industry, Science and Technology and Assistant Minister for Industry Development

publish more information/data, and prohibits service providers from increasing the charges payable by existing shippers to cross-subsidise the development of new capacity.

The reforms are expected to:

- lower transportation costs
- improve access to pipelines
- lower search and transaction costs
- provide a range of other significant cost savings investment and efficiency benefits
- materially reduce the risks associated with the regulatory framework
- facilitate more effective competition in gas transportation and in upstream and downstream markets.

Net economy-wide benefits of the reforms are expected to be between $235m and $1.18b.

The reforms are now being developed into a draft legislative amendment package, with consultation and agreement of the Energy National Cabinet Reform Committee to follow before an amendment to the National Gas Law and National Gas Rules. If passed into legislation, these reforms could influence the investment decisions of private gas pipeline developers in the Bowen Basin.

Queensland's COVID-19 Economic Recovery Plan[26]

Queensland's COVID-19 Economic Recovery Plan encompasses a suite of initiatives that forms the Queensland Government's response to the COVID-19 pandemic and resulting economic impacts.

The Plan presents a vision which includes protecting the health of every Queenslander, creating jobs, and working together to create the conditions for future success. It identifies six key focus areas to deliver this vision:

- Safeguarding our Health
- Backing small business
- Making it for Queensland
- Building Queensland
- Growing our regions
- Investing in skills.

The Plan also allocates $5m to complement Commonwealth funding for the Bowen Basin pipeline concept/pre-feasibility study. Specifically, this funding features in the Central Queensland and Mackay-Whitsunday Regional Economic Recovery Plans.[27,28]

This Bowen Basin Gas Pipeline concept study forms part of Queensland's COVID-19 Economic Recovery Plan and aims to contribute to the recoveries of both the regions and the state. It will explore options to unlock the Bowen Basin's gas supply and whether they can contribute to the Plan's vision of creating the conditions for future success, in terms of Queensland's energy and economic future.

[26] (Palaszczuk & Dick, 2020)
[27] (Queensland Government, 2020)
[28] (Queensland Government, 2020)

Queensland Draft State Infrastructure Strategy[29]

The Queensland Government's State Infrastructure Strategy forms the overarching framework for infrastructure development in Queensland; it sets state-wide priorities and planning direction, which will then inform the regional infrastructure plans that are currently being developed for Queensland's seven regions. Over the next twenty years, the Strategy aims to deliver on its vision:

> "We will drive collaborative state infrastructure planning to boost productivity, grow our economy and create jobs. Infrastructure planning and delivery will leverage opportunities to improve the liveability of our communities and capitalise on innovation to build a strong, sustainable and resilient Queensland."

The objectives that the plan targets in order to realise this vision include:

- Encourage jobs, growth, and productivity
- Develop regions, places and precincts
- Enhance sustainability and resilience
- Adopt smarter approaches.

This study explores options to unlock gas supply in the Bowen Basin in such a way that would generate economic benefits and jobs for Queensland. As such, it aligns with the first objective of the Strategy (Encourage jobs, growth, and productivity).

Queensland Climate Transition Strategy[30]

In the Queensland Climate Transition Strategy, the Queensland Government outlines a state target of zero net emissions by 2050, with an interim target of 30% reduction in emissions on 2005 levels by 2030. The Strategy outlines the actions that the Queensland Government will progress in order for Queensland to realise these targets.

One key focus of the Bowen Basin Gas Pipeline concept study is to explore ways to better manage incidental coal mine gas, in order to both increase the overall productivity of coal mining from an energy source perspective as well as to decrease fugitive emissions from an environmental perspective. In decreasing fugitive emissions, a solution in the Bowen Basin could contribute to achieving Queensland's emissions reduction targets.

Queensland Climate Action Plan[31]

The Queensland Climate Action Plan represents a collection of plans, actions and projects (planned and in progress) that contribute to Queensland's renewable energy and emissions reduction targets, and the transition to a more sustainable economy.

Among the 370 project case studies referenced, the Bowen Basin Gas Pipeline concept study is listed as an action being undertaken to drive climate action. As identified, the concept study explores options that could contribute to achieving Queensland's emissions reduction target.

Queensland Renewable Energy Zones[32]

In May 2021, the Queensland Government declared three renewable energy zones in Queensland (QREZs) that are particularly to being conducive to renewable resource development, as identified by AEMO (see Figure 101). The Queensland Government has allocated $145 million to undertake strategic [electricity] network investments, streamline the development of new renewable energy projects and increase the supply of renewable energy. The majority of this development will be solar and wind farms, and electricity transmission network solutions.

It is appropriate to consider the Bowen Basin Gas Pipeline concept in the context of the QREZs, especially the Central QREZ, because both aim to address Queensland's energy future. Specifically,

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29 (Department of State Development, Infrastructure, Local Government and Planning, 2021)
30 (Department of Environment & Heritage Protection, 2017)
31 (Department of Environment and Science, 2021)
32 (Department of Energy & Public Works, 2021)

electricity generation and transmission play a downstream role for any gas resources that are intended for electricity generation. Developing the Bowen Basin's gas reserves to provide more electricity into the NEM will require considering the downstream infrastructure needed and the role that QREZs can play in enabling this.

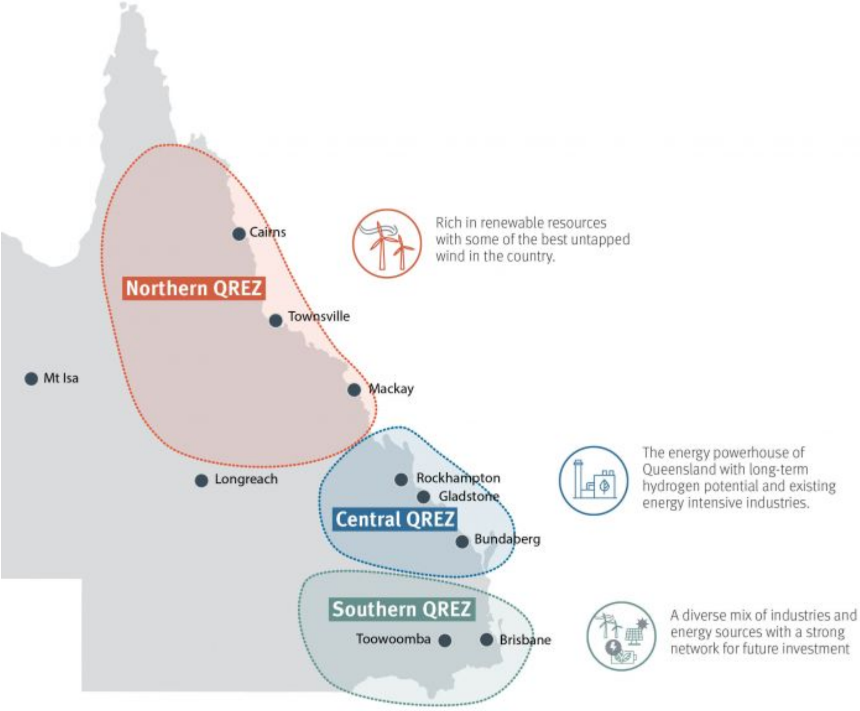

Figure 101 Map of Queensland REZs

Source: (Department of Energy & Public Works, 2021)

Queensland Resources Industry Development Plan (QRIDP)[33]

The Queensland Government is currently developing a Queensland Resources Industry Development Plan (QRIDP) with a draft plan scheduled for release in late 2021 before the final plan's publication in 2022. It aims to outline a long-term strategic vision for Queensland's resources industry as well as a roadmap to realise this vision. Key focus areas will include:

- removing barriers to resources industry growth
- helping regional communities recover from the impacts of COVID-19
- responsibly unlocking Queensland's precious resources.

Central Queensland Regional Plan[34]

Released in 2013, the Central Queensland Regional Plan covers the following LGAs:

- Banana Shire Council
- Central Highlands Regional Council
- Gladstone Regional Council
- Livingstone Shire Council
- Rockhampton Regional Council
- Woorabinda Aboriginal Shire Council.

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33 (Queensland Government, 2021)
34 (Department of State Development, Infrastructure & Planning, 2013)

The Plan aims to provide "strategic direction and policies to deliver regional outcomes which align with the state's interests in planning and development". The two regional outcomes identified in the Plan are:

- Agriculture and resources industries within the Central Queensland region continue to grow with certainty and investor confidence.
- The growth potential of towns within the Central Queensland region is enabled through the establishment of Priority Living Areas. Compatible resource activities within these areas which are in the communities' interest can be supported by local governments.

While the Plan does not reference gas supply or development specifically, it does highlight the regional issue of land use competition between the agricultural and resources sectors. It also places value on promoting the liveability of communities, economic growth and environmental sustainability.

This Concept Study explores opportunities for the development of Bowen Basin gas reserves to contribute to the region's economic growth and also to environmental sustainability through fugitive emissions reduction.

Mackay, Isaac and Whitsunday Regional Plan[35]

Released in 2012, the Mackay, Isaac and Whitsunday Regional Plan covers the following LGAs:

- Mackay Regional Council
- Isaac Regional Council
- Whitsunday Regional Council.

The Plan sets a regional vision for 2031:

> "The Mackay, Isaac and Whitsunday region is a vibrant, progressive region where the values of the community and industry are respected and in balance with the natural environment. The region's natural assets and abundant resources will be responsibly managed for the benefit of residents, visitors and future generations. It achieves its potential with a range of industries, employment and learning opportunities for everyone. The region has a resilient and inclusive community that respects and offers diversity and choice, and where residents and visitors enjoy a healthy, active and safe lifestyle."

The Plan also provides policy direction in order for the regional vision to be realised, organised into ten desired regional outcomes. Three of these outcomes are directly relevant to this Bowen Basin Concept Study:

- **Outcome 1:** The region grows and changes in a sustainable manner generating prosperity, maintaining and enhancing quality of life, minimising the use of resources, providing high levels of environmental protection, reducing greenhouse gas emissions, and increasing resilience to natural hazards and the anticipated effects of climate change.
- **Outcome 6:** A thriving regional economy that is sustainable, resilient and robust, and advances the prosperity and liveability of communities across the region.
    - ***Policy 6.5.3:*** Identify and support new sectors that have the potential for future growth associated with the resource sector such as mine rehabilitation and carbon dioxide emissions capture
    - ***Policy 6.5.6:*** Ensure sufficient supply of minerals, gas and extractive resources are available for future use, and their extraction, processing, transport and downstream value-adding contribute to the local economy

[35] (Department of Local Government & Planning, 2012)

- **Outcome 9:** The region's communities have access to well-planned, coordinated, accessible, sustainable and reliable infrastructure.
  - ***Policy 9.3.4:*** The use of gas distribution networks are optimised and expanded, and, where viable, the use of gas as an additional energy source is encouraged for new developments.

This Concept Study assesses opportunities to reduce emissions through productive use of incidental coal mine gas, which aligns with Outcome 1 and Policy 6.5.3. This Concept Study also explores options to increase gas supply through the development of gas reserves in the Bowen Basin, and associate infrastructure – this would advance the achievement of Policy 6.5.6 and Policy 9.3.4. Finally, this Concept Study explores the opportunity for any investment or development of the Bowen Basin to contribute to the Region's economic recovery and growth, which would broadly contribute towards Outcome 6.

Appendix C: Approval Options

The following sections detail a breakdown on the potential approval requirements for the development of the Basin.

Environmental Protection & Biodiversity Conservation Act 1999

The *Environment Protection and Biodiversity Conservation Act 1999* (Cwth) (EPBC Act) is the Commonwealth Government's central environmental legislation.

The EPBC Act provides protection for Matters of National Environmental Significance (MNES) against actions that have or are likely to significantly impact any MNES. An action that has or is likely to significantly impact an MNES is known as a 'controlled action'. Under the EPBC Act, to undertake a controlled action without approval from the Minister is prohibited.

There are currently nine MNES protected under the EPBC Act, including:

1) Listed threatened species and ecological communities

1) List migratory species

2) Wetlands of international importance

3) The Commonwealth marine environment

4) World Heritage properties

5) National Heritage places

6) Nuclear actions

7) Great Barrier Reef Marine Park

8) Protection of water resources from coal seam gas development and large coal mining development (otherwise referred to as the water resource trigger).

The Department of Agriculture, Water and Environment (DAWE) recommends that a project carry out a self-assessment as the first step in determining if referral and assessment under the EPBC Act is required. The purpose of the self-assessment is to determine if the project will or is likely to significantly impact an MNES.

Should the self-assessment identify the potential for a significant impact to any MNES, referral to the Commonwealth is required. Alternatively, if the self-assessment identifies that the action will not or is unlikely to have a significant impact on any MNES, a referral to the Commonwealth is not required by law.

It is highly likely that a gas development in the Bowen Basin would trigger a controlled action under the EPBC Act, at the very least for listed threatened species and ecological communities, and for protection of water resources from coal seam gas development.

Declaration as a Coordinated Project under the State Development and Public Works Organisation Act 1971

A proponent of a project with one or more of the following characteristics may apply to have it declared a 'coordinated project' with the State of Queensland:

- Complex approval requirements, involving local, state and federal governments;
- Significant environmental effects;

- Strategic significance to the locality, region or state, including for the infrastructure, economic and social benefits, capital investment or employment opportunities it may provide significant infrastructure requirements; or

- Significant infrastructure requirements.

The Queensland Coordinator-General chooses the weight attributed to each of the above factors in making the decision to declare a project a co-ordinated project. The Coordinator-General is not bound to declare a project a coordinated project because it satisfies one or more of these characteristics.

In making the declaration decision, the Coordinator-General must consider:

- Detailed information about the project given by the proponent in an Initial Advice Statement;

- Relevant planning schemes or policy frameworks of a local government, the State or the Commonwealth;

- Relevant State policies and Government priorities;

- A pre-feasibility assessment of the project, including how it satisfies an identified need or demand;

- The capacity of the proponent to undertake and complete the environmental impact statement (EIS) or impact assessment report (IAR) for the project; and

- Any other matter considered relevant.

There are two types of coordinated project declaration:

- Requiring an EIS

- Requiring an IAR

Details of the usual scope of an EIS and an IAR are outlined below. Generally, the IAR is a more straightforward assessment aimed at projects whose potential impacts are well understood and predictable. The declaration of a 'coordinated project' in accordance with the SDPWO Act, means that the procedures to secure the required project approvals would be simplified and 'fast-tracked' as a result of the 'whole of government' approach that attends such a declaration.

Scope of an EIS

The EIS is prepared in accordance with the terms of reference for the EIS. The EIS provides a comprehensive description of:

- The state of environment in the area of the project

- All potential environmental impacts of the project, including spatial and temporal considerations, as well as direct, indirect, reversible, irreversible, interactive, synergistic and cumulative effects resulting from the construction, commissioning, operation and decommissioning phases of the project.

- Proponent proposals to avoid, minimise, mitigate and/or offset those potential impacts.

Scope of an IAR

An IAR process may be used if the Coordinator-General is satisfied that the environmental effects of the project do not (having regard to their scale and extent) require assessment through the EIS process. It may be used for well-defined, low-medium risk projects where the likely impacts are highly predictable and the proponent's well-defined proposals to avoid, minimise, mitigate and/or offset those impacts are accepted best-practice in that industry.

The IAR:

- Has no formal terms of reference; and
- Is focused mostly on the:
  - Locations that may be subject to adverse impacts if not appropriately managed
  - Potential impacts that are either uncertain, or proposed mitigation measures that depart from accepted management practices or standard conditions for that industry.

Advisory Agencies

The Office of the Coordinator-General manages the State Government's evaluation of the project.

A wide range of Government departments (known as 'advisory agencies') are responsible for reviewing the draft EIS or IAR and will involve the likes of Department of Resources, Department of Environment and Science, Department of Agriculture and Fisheries, and Department of Transport and Main Roads.

Other Approval Processes Suspended

The coordinated project process replaces the information and referral stages of a related assessment under both the *Queensland Planning Act 2016* and an environmental authority under the *Environmental Protection Act 1994*.

The decision stage under both of these Acts commences when the Coordinator-General's evaluation report on the EIS or IAR is provided to the relevant assessment.

Option to Apply for Declaration as a Prescribed Project

A proponent of a Coordinated Project may also apply to have the project declared a "prescribed project" pursuant to section 76e of the SDPWO Act (Qld). The application to have a project declared a prescribed project is made through the office of the Co-ordinator General. The Office of the Co-ordinator General assesses the merit of the application and makes a recommendation to the minister. The formal declaration is ultimately made by the Minister by Gazette notice.

The declaration as a "Prescribed Project" provides a number of benefits including enabling the Coordinator General, if necessary, to intervene in state and local government approval processes to assist and ensure timely decision-making for the prescribed project.

The Office of the Coordinator-General can overcome unreasonable delays in obtaining project approvals by:

- Acting as a point of contact for the proponent within Government to streamline Government communications;
- Coordinating local and State Government agencies regarding statutory approvals required for the project; and
- Facilitating discussions and information exchanges between the proponent and other stakeholders (e.g. local authorities and State Government agencies).

A prescribed project declaration is most effective when used to obtain the final approvals after Tier 1 approvals have already been provided by the Coordinator-General or another authority.

The types of projects that may be declared prescribed projects include:

- Works a 'local body', the Coordinator-General, or other person is directed to undertake under the SDPWO Act
- A project in a state development area.

- An infrastructure facility (as defined in the SDPWO Act – see below).
- A project declared a 'coordinated project'.
- Another project the minister considers is economically or socially significant to Queensland or the region in which the project is to be undertaken or affects an environmental interest of Queensland or a region.

SDPWO Act definition of infrastructure facility includes any of the following:

a road, railway, bridge or other transport facility

a jetty or port

an airport, landing strip or spaceport

an electricity generation, transmission or distribution facility

a storage, distribution or gathering or other transmission facility for:

i) oil or gas; or

ii) derivatives of oil or gas

a storage or transportation facility for coal, any other mineral or any mineral concentrate

a dam, water storage facility, pipeline, channel or other water management, distribution or reticulation facility

a cable, antenna, tower or other communication facility

infrastructure for health or educational services.

Appendix D: CMM treatment for utilisation

Gas dehydration

Gas dehydration is one of the main functions of any gas processing hubs. It is important to remove water from the gas due to the following:

- Under certain conditions gas can combine with liquid or free water to form solid hydrates that can plug valves fittings or scale pipelines, leading to unsafe situations or higher-pressure drops in transmission systems
- Water vapour can condense in pipelines, especially at higher pressures, causing slug flow and possible erosion and corrosion
- Water vapour increases hydraulic loading and decreases the heating value of the gas
- Downstream customers' feed gas specification(s) typically require a feed gas of specific heating value and zero free water, although water saturated gas can be tolerated
- Water vapour is most commonly removed via liquid desiccant (i.e. physical solvent) processes such as glycol dehydration. Glycol dehydration is most prevalent in the Queensland coal seam gas industry, although other technologies are commercially available.

Mine capture gas can contain appreciable amounts of acid gas impurities, such as H_2S, COS and CO_2. The presence of these "sour" impurities in the presence of water saturated gas can lead to higher corrosion potential in mechanical equipment, displaces hydraulic capacity in process systems and also reduces heating value of the gas. Generally, treatment processes are adsorption of absorption based. Adsorption refers to physical processes wherein impurities are concentrated on the surface of a solids. These types of processes are usually for trim or residual impurity treatment only. Bulk or large-scale acid gas removal is accomplished through chemical absorption processes and may be once through wash systems or more complex, multistep processes with regeneration steps. Most gas processing plants utilise a process with selective absorption of contaminants into a liquid solvent (such as ethanolamine), which is passed counter-current to the gas in an absorber column. Other technology options, for example those based on physical rather than chemical absorbents, (Selexol® or Rectisol®), will not be discussed here.

For mine gas collection systems used to collect post drainage or goaf gas, the concentration of oxygen and nitrogen can be significant. Some amount of airflow migrates to the goafs during the routine ventilation of underground mines and due to their porosity and migration through goafs and back to long wall faces, goaf gas will contain a mixture of methane, oxygen, carbon dioxide and nitrogen. The main commercial technology for oxygen removal is based on catalytic oxidation in a reactor, while nitrogen removal is commonly done through cryogenic separation or pressure swing adsorption. Some adsorption and membrane-based processes have shown to be effective, but they are limited in commercial application

Acid Gas Removal

Mine gas, like natural gas or CSG, while predominantly hydrocarbon in nature can contain appreciable amounts of acid gas impurities, such as H_2S, COS and CO_2. The presence of these "sour" impurities in the presence of water saturated gas can lead to higher corrosion potential in mechanical equipment.

There are a few variables in treating acid gas:

- Types and concentrations of contaminants in the gas;
- Degree of contaminant removal desired;

- Selectivity of acid gas removal required (i.e. lower proportions of sulphur in mine gas, compared to conventional gas resource, may affect process design);
- Temperature, pressure, volume, and composition, of the gas to be processed;
- Carbon dioxide–hydrogen sulphide ratio in the gas; and
- Requirement for sulphur recovery – not likely for mine gas acid treatment of gas to be vented to atmosphere if within air quality regulations(s). Alternatively, sulphur guard beds to be employed for extraction of sulphur from off-gas.

If a gas contains appreciable amounts of other sulphur components different sweetening methods and/or solvents may need to be considered, which can affect process economics. Note that most mine gas in regional Queensland does not actually exhibit high levels of sulphur, meaning that acid gas plants should be designed with selectivity towards CO2.

Generally, treatment processes are either adsorption or absorption based. Adsorption refers to physical processes wherein impurities are concentrated on the surface of a solids. These types of processes are usually for trim or residual impurity treatment only. Bulk or large-scale acid gas removal is accomplished through chemical absorption processes and may be once through wash systems or more complex, multistep processes with regeneration steps. Most gas processing plants utilise a process with selective absorption of contaminants into a liquid solvent (such as ethanolamine), which is passed counter current to the gas in an absorber column. This section will only discuss the more common, amine-based processes. Other technology options, for example those based on physical rather than chemical absorbents, (Selexol® or Rectisol®), will not be discussed here.

Depending on the composition and operating conditions of the feed gas, different amines can be selected to meet the product gas specification. Amines are categorized as being primary, secondary, and tertiary depending on the degree of substitution of the central nitrogen by organic groups. Primary amines react directly with H2S, CO2, and carbonyl sulfide (COS). Some licensed processes combine amine and inorganic solvents in proprietary mixes. Depending on choice of solvent, varying degrees of pre-treatment and operational controls (e.g. heat integration) may be required to limit solvent degradation, which can occur at elevated temperatures or in the presence of certain additional impurities (e.g. dissolved oxygen). The build-up of heat stable salts can also lead to increased makeup requirements for the solvent.

The principal reaction occurs when the lean solvent solution enters the absorber through which the sour gas is bubbled. Purified gas leaves the top of the tower, and the rich amine solution leaves the bottom of the tower with the absorbed acid gases. The degree of sweetening achieved is largely dependent on the number of trays or the height of packing available in the absorber. The rich solvent enters a stripper regenerator tower where heat and/or lower pressure drives the acid gases from the solution. The regenerated amine solution, restored to its original condition, leaves the bottom of the regenerator tower while acid gases are released from the top of the regenerator.

Amine based processes can be energy intensive but relaxing the specification on acid gas levels in the purified product gas can reduce energy and capital intensity. Most processes are near identical, although consultation with specialist providers or licensors is recommended to define optimal plant configurations. Operational experience has also shown that amine gas treatment is a fouling service with particulate/salt formation. Therefore, some plants will employ different degrees of filtration steps.

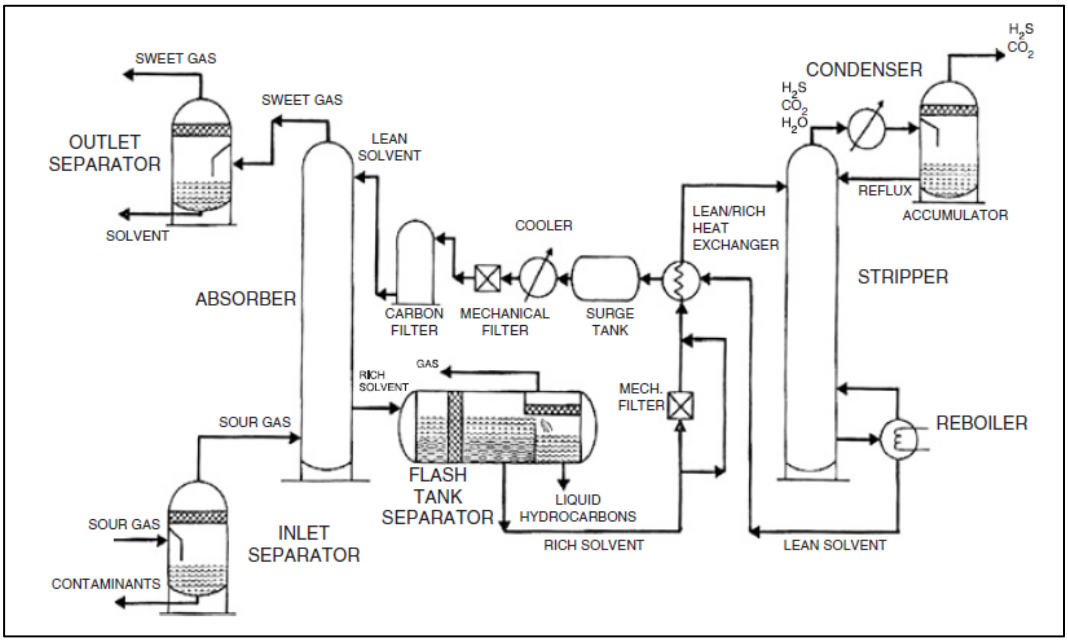


Figure 102 – Generalised Amine based Acid Gas Treatment with Flash Vessel
(Source: Handbook of Natural Gas Processing. Speight et al. (2006).

Oxygen Removal

Generally, coal seam gas does not contain appreciable amounts of oxygen, other than what may ingress in low pressure collection systems. However, for mine gas collection systems used to collect post drainage or goaf gas, the concentration of oxygen and nitrogen can be significant. Some amount of airflow migrates to the goafs during the routine ventilation of underground mines and due to their porosity and migration through goafs and back to long wall faces, goaf gas will contain a mixture of methane, oxygen, carbon dioxide and nitrogen. A very real hazard associated with mining operations is the spontaneous eruption of underground fires, with consequent release of toxic and asphyxiant gases, which illustrates that combustible atmospheres and measurable concentrations of oxygen can be present in coal mine gas. Often mines employ a range of methods to control goaf gas flow and is driven by health and safety.

The main commercial technology for oxygen removal is based on catalytic oxidation in a reactor. Some adsorption and membrane-based processes have shown to be effective, but they are limited in commercial application. The catalytic removal of oxygen from a methane stream requires the gas to be passed over a catalytic bed at an elevated temperature where the oxygen reacts with a small portion of the methane gas to produce water and CO_2. A minimum concentration of oxygen is required to ensure sufficient temperature in the reactor unit, which in turn ensures proper conversion of oxygen to water and CO_2. At lower concentrations of oxygen supplementary heating (e.g. via an electric or fired heater) may be required. Oxygen removal units are normally designed for 0.2 – 3% (m/m%) concentration in the feedgas. Some literature[36] suggests that oxygen can be reduced to below 10 parts per million (by volume, ppmv).

Nitrogen Removal/Rejection Units (NRUs)

Nitrogen must be removed from natural gas to reduce transportation volumes, increase heating value and to meet pipeline specifications. NRUs are most applicable for post- drainage, mine gas systems and are not required for conventional CSG operations. It should be noted that pipeline gas specifications can allow for up to 7 mol percent of inert gas.

[36] Rhodes, Z., (2008) "O2 Removal Key To Tower Mine Project", American Oil and Gas Reporter, Is.

Cryogenic NRUs are fairly common installations at large capacity plants, and they are often coupled with hydrocarbon (i.e. C2+ sales gas) recovery units at LNG facilities. In the case of coal mine methane gas, with practically no economically recoverable C2+ components, a standalone, auto-refrigeration rejection unit is more suitable and would offer the highest recovery of methane. Cryogenic NRUs do however require heavy metal removal (e.g. mercury) and have stringent specifications on moisture and CO_2 content. A standard cold box unit will produce methane purity in excess of 95%, up to 98%. With additional processing equipment, a small portion of liquid nitrogen can also be produced, which may be sold onto local market or stored for utility purposes.

In recent times there has been a large amount of research and development effort in the commercialization of physical separation processes for NRUs, using membranes or molecular swing adsorption technologies. The market need for cheaper NRU technologies is also increasing due to the proportion of lower quality reserves in the total gas mix. Future production is also likely to increase from smaller, more remote fields as production from established high quality fields begins to decline. Therefore, technologies that can treat smaller gas streams, with relatively low energy requirements, will begin to compete well with cryogenic NRUs. Pressure swing adsorption (PSA) units are currently the most commercially advanced alternative to cryogenic units. Note that a detailed section study for choice of NRU technology is appropriate in subsequent phases of project development, particularly given the advancement of membrane technologies over the last >5 years.

Molecular sieve or PSA units are termed a physical process because nitrogen, and other components, are physically adsorbed to a molecular sieve or zeolite adsorbent bed while passing methane. In a typical application feed gas is compressed from low pressure to ~700 kPag using an oil flooded screw compressor and fed to a PSA vessel. The unit is operated cyclically, with a number of vessels operating in a controlled sequence to deliver a constant flow of product gas.

It is typical for a PSA unit to require about 100 kPa for pressure drop. Depending on downstream operations, the product gas will then enter a multistage, reciprocating compressor for pipeline transmission. It is worth noting that some technology suppliers have shown success in meeting pipeline gas specifications with both high levels of CO_2 and Nitrogen in feed gas, especially where both inerts are in the same relative quantity (e.g. ~10mol% CO_2, 10mol% N_2). The main disadvantage with such a physical system is that during the purge sequence a high vacuum must be achieved to provide effective desorption from the adsorbent. This requires a vacuum pump or other vacuum system. In the absence of a perfect vacuum, there will always be "slip" of the inert molecules to the product gas. Generally, recovery of methane is limited to about 95-97%, which at commercial scale can be significant given that cryogenic units can achieve recoveries greater than 99.5%.

Typically, these units are sold as skid mounted packages and therefore may be modularized to suit application. In the absence of sour gas contaminants, the molecular sieve technology is well suited to replace amine plants and cryogenic NRUs.

Appendix E: Socio-demographic baseline

The study area used to establish the baseline includes the following five LGAs, based on the study area defined in Queensland Treasury's Bowen Basin Population Report (see Figure 103).

- Whitsunday (R)[37]
- Isaac (R)
- Central Highlands (R)
- Woorabinda (S)[38]
- Banana (S)[39]

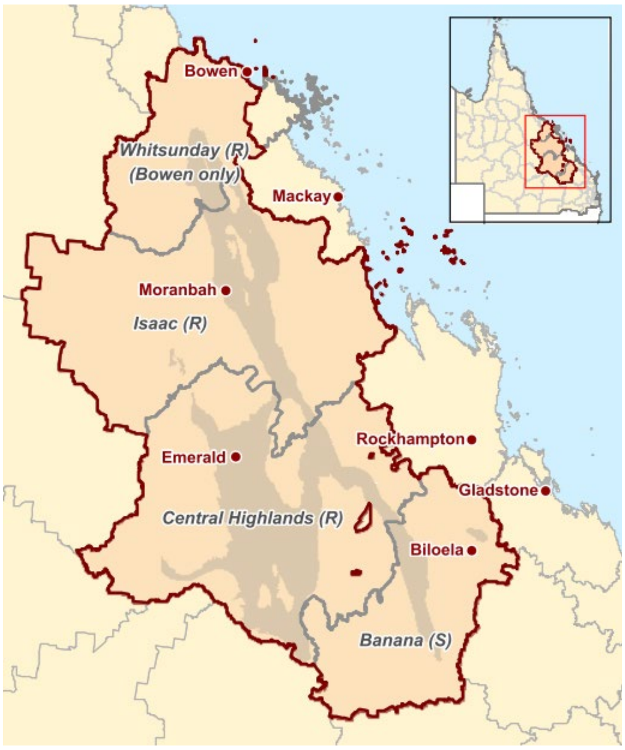


Figure 103 - Queensland Treasury's Bowen Basin population report (2020) study area

Source: (Queensland Treasury, 2021)

1. Population

Table 41 presents an overview of the study area's population and trends over time. Currently, there are estimated to be 86,636 residents across the study area, which represents less than 1% of the Queensland population. The largest shares of these residents can be found in Whitsunday (41%) and Central Highlands (33%). Woorabinda accounts for only 1% of the study area's population.

Over the past 11 years, the study area's population has grown at 0.3% per annum on average, slower than the Queensland average (1.6% p.a.). The study area had an annual growth rate of over 1% up until 2012, after which the study area's population began to grow at a slower rate before experiencing negative annual growth between 2014 and 2018, which is reflected in the five year moving average in

[37] In 2008, the Shire of Bowen and the Shire of Whitsunday merged to form the Whitsunday Region. The Queensland Treasury report uses the old Shire of Bowen boundaries, excluding the Shire of Whitsunday area. This study will include the entire Whitsunday Region.
[38] The Queensland Treasury report excludes the Aboriginal Shire of Woorabinda. It is included in this study area.
[39] (R) indicates a region, (S) indicates a shire.

Figure 104. This slowing growth was predominantly driven by Isaac and Central Highlands experiencing the largest decreases in annual growth rate. As these are the two LGAs with the highest concentrations of mining operations (see Figure 107), the decrease in population growth rate is likely partly attributable to the end of the late 2000s mining boom. In the past few years, the annual population growth rate across the study area has increased.

Over the next 11 years to 2031, the study area is expected to add 7,375 residents giving an average annual rate of 0.7%, again slower than Queensland (1.7% p.a.). Most LGAs will likely see their growth rates increase, except for Woorabinda whose population is expected to decrease. (-0.8% p.a.). Banana is also expected to see population decline but at a slower rate (-0.4% p.a.).

Over the past eleven years, the populations of the four regional LGAs with predominantly primary industry have hardly grown compared to Whitsunday, which has a high concentration of tourism. This trend is expected to continue into the future.

Table 41 - Estimated resident population and projections.
(Source: KPMG Analysis)

	Estimated resident population			Compound average annual growth rate	
	2009	**2020**	**2031**	**2009 – 2020**	**2020– 2031**
Whitsunday	31,838	35,927	41,072	1.1%	1.2%
Isaac	22,237	20,987	22,709	-0.5%	0.7%
Central Highlands	28,714	28,727	29,319	0.0%	0.2%
Woorabinda	934	995	910	0.6%	-0.8%
Banana	14,941	14,065	13,518	-0.5%	-0.4%
Study area	**83,723**	**86,636**	**94,011**	**0.3%**	**0.7%**
Queensland	*4,328,771*	*5,176,186*	*6,206,566*	*1.6%*	*1.7%*

Sources: ABS.Stat, 2021, ERP by LGA (ASGS 2020), 2001 to 2020; Queensland Government Population Projections, 2018 edition (medium series).

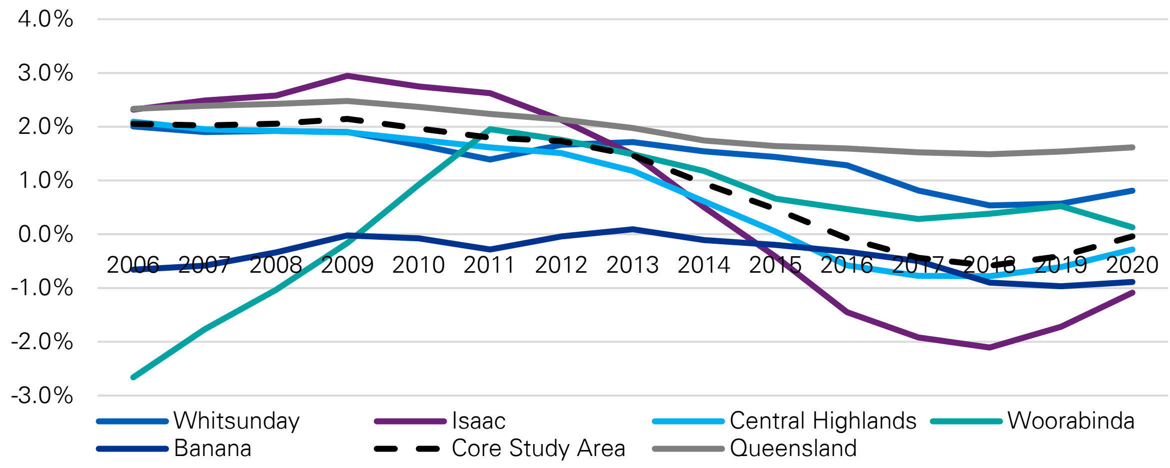


Figure 104 - Population annual growth rate, 5 year moving average.
(Source: KPMG Analysis)

Source: ABS, 2021, Estimated Resident Population by Local Government Area (ASGS 2020), 2001 to 2020.

Table 42 presents an overview of the study area's Indigenous population and trends over time. As of the 2016 Census, the study area was home to 5,077 residents that identified as Indigenous (Aboriginal, Torres Strait Islander or both), representing 5.2% of the study area's total population. The study area's average proportion is higher than the Queensland average (4.0%), as is each LGA except Isaac (3.6%). Woorabinda, as an Aboriginal Shire, has a significant Indigenous population (94.1%).

In line with the overall Queensland trend, the proportion of Indigenous residents in the study area has increased since 2006. This is mirrored in each LGA except Woorabinda.

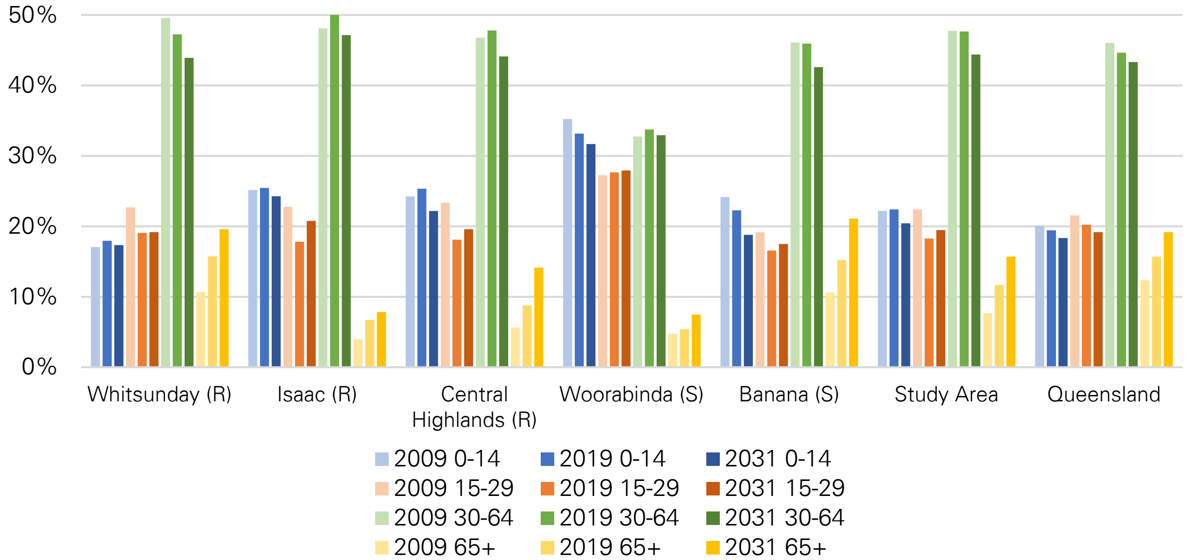
Table 42 - Indigenous population, Census data.
(Source: KPMG Analysis)

	2006		2011		2016	
	Indigenous population	**% of Total**	**Indigenous population**	**% of Total**	**Indigenous population**	**% of Total**
Whitsunday	1,131	3.9%	1,338	4.3%	1,639	4.9%
Isaac	418	2.1%	599	2.7%	744	3.6%
Central Highlands	892	3.4%	1,018	3.5%	1,209	4.3%
Woorabinda	803	94.7%	880	93.2%	905	94.1%
Banana	460	3.1%	583	4.0%	580	4.1%
Study area	**3,704**	**4.1%**	**4,418**	**4.5%**	**5,077**	**5.2%**
Queensland	*127,584*	*3.3%*	*155,823*	*3.6%*	*186,489*	*4.0%*

2. Age Distribution

The figure above illustrates trends over time for select age categories, by proportion of the total population.

Figure 105: Subsets of the population by age categories.



Sources: ABS. 2010. 3235.0 Population by Age and Sex, Regions of Australia, Table 6. Estimated Resident Population by Age, Queensland, Persons – 30 June 2009; ABS. 2020. 3235.0 Regional Population by Age and Sex, Australia, Table 3. Estimated Resident Population by Age, by Local Government Area, Persons – 30 June 2019; Queensland Government. 2018. Population projections, 2018 edition - medium series.

Children (0-14)

The study area's share of children (22.4%) is higher than the Queensland average (19.4%). Woorabinda has the highest share (33.2%) while Whitsunday has the lowest (17.9%).

Over the past ten years, this share has marginally increased over the study area (0.2 percentage points from 22.2%), while the Queensland average has decreased (0.7pp from 20.1%). The only two LGAs which did not experience an increase were Woorabinda (2.0pp decrease) and Banana (1.9pp decrease).

Over the next ten years, the share of under-14-year-olds is expected to decrease across the study area (2.0 percentage points to 20.4%), faster than the Queensland average (1.1pp to 18.3%). Banana is expected to see the largest decrease (3.5pp).

Young workers and school-leavers (15-29)

The study area's share of 15 to 29-year-olds (18.3%) is lower than the Queensland average (20.2%). Woorabinda has the highest share (27.7%) while Banana has the lowest (16.6%).

Over the past ten years, this share has decreased over the study area (4.1 percentage points from 22.4%), while the Queensland average has similarly decreased (1.3pp from 21.6%). The only LGA to not experience a decrease was Woorabinda (0.4pp increase).

Over the next ten years, the share of young workers and school-leavers is expected to increase across the study area (1.2 percentage points to 19.5%), whereas the Queensland average is likely to decrease (1.0pp to 19.2%). Central Highlands is expected to see the largest increase (3.0pp), while Whitsunday is only expected to grow marginally (0.1pp).

Prime and mature working population (30-64)

The study area's share of prime and mature working-aged residents (47.7%) is higher than the Queensland average (44.6%). Isaac has the highest proportion (50.0%) and Woorabinda has the lowest (33.8%).

Over the past ten years, this proportion has not changed across the study area, while the Queensland average decreased (1.4pp from 46.0%). Whitsunday saw a substantial decrease (2.3pp), and Isaac, Central Highlands and Woorabinda increased by between one and two percentage points.

Over the next ten years, this subset's share of the total population is expected to decrease across the study area (3.3 percentage points to 44.4%), slower than the Queensland average (1.3pp decrease). This is mirrored in each LGA, most substantially in Central Highlands (3.7pp decrease).

Senior population (65+)

The study area's share of over-65-year-olds (11.7%) is lower than the Queensland average (15.7%). Whitsunday contains the largest share (15.7%) and Woorabinda has the lowest (5.4%).

Over the past ten years, this proportion has increased across the study area (3.4 percentage points from 8.2%), faster than the Queensland average (2.8pp from 12.9%). All LGAs echoed this increase, with the largest occurring in Whitsunday (4.2pp).

Over the next ten years, the senior subset of the population is expected to continue to increase across the study area (4.0 percentage points to 15.7%), faster than the Queensland average (3.5pp to 19.2%). This trend is expected to happen in each LGA, at the fastest rate in Banana (5.9pp).

Overall trends

The Bowen Basin is home to proportionally more children and prime and mature working-aged residents than Queensland. Conversely, the area has a smaller share of young workers and senior residents than the Queensland average. This may indicate that people move to the Bowen Basin for work; it may also indicate that there is a trend of outward migration upon reaching school-leaving age (for tertiary education or urban career paths) and retirement age.

Over the next decade, the area is expected to largely follow predicted state-wide trends such as an ageing population, although notably may face a more-substantial decrease in working-age residents. This may have implications for the labour market and for industry in the Bowen Basin into the future.

3. Labour Force

Table 43 presents an overview of labour force statistics for the study area. As of March 2021, the labour force across the study area was 60,488 people. The participation rate of the labour force (aged 15 and over) as of June 2019 was 73.1%, significantly higher than the Queensland average of 52.1%. Woorabinda had the highest rate (87.2%) while Whitsunday had the lowest (66.7%).

In March 2021, there were 57,742 employed people in the study area, giving an overall unemployment rate (4.5%) much lower than the Queensland average (7.3%). Isaac had the lowest unemployment rate (2.0%) while Woorabinda had the highest (7.3%).

Over the 12 months to March 2021, unemployment rates increased in both the study area (0.4 percentage points) and Queensland (1.2 pp). This 12-month period covers the onset of the COVID-19 pandemic and accompanying economic downturn, which can help explain the state-wide trend. Whitsunday faced the largest increase across the study area (1.0pp), in line with the broader Queensland average, while the other LGAs were far less impacted or even, in the case of Woorabinda, even decreased (-1.1pp). Whitsunday's position as an outlier in terms of unemployment can be seen in Figure 106, in which it is the only LGA which has a range of unemployment rate greater than 2.0 percentage points (~6.0pp). Whitsunday's increase in unemployment in the 12 months to March 2021 may be attributable in part to its larger sector concentration of (and reliance) tourism – noting that lockdown restrictions and social gathering requirements apply strongly to tourism, whereas mining was far less affected.

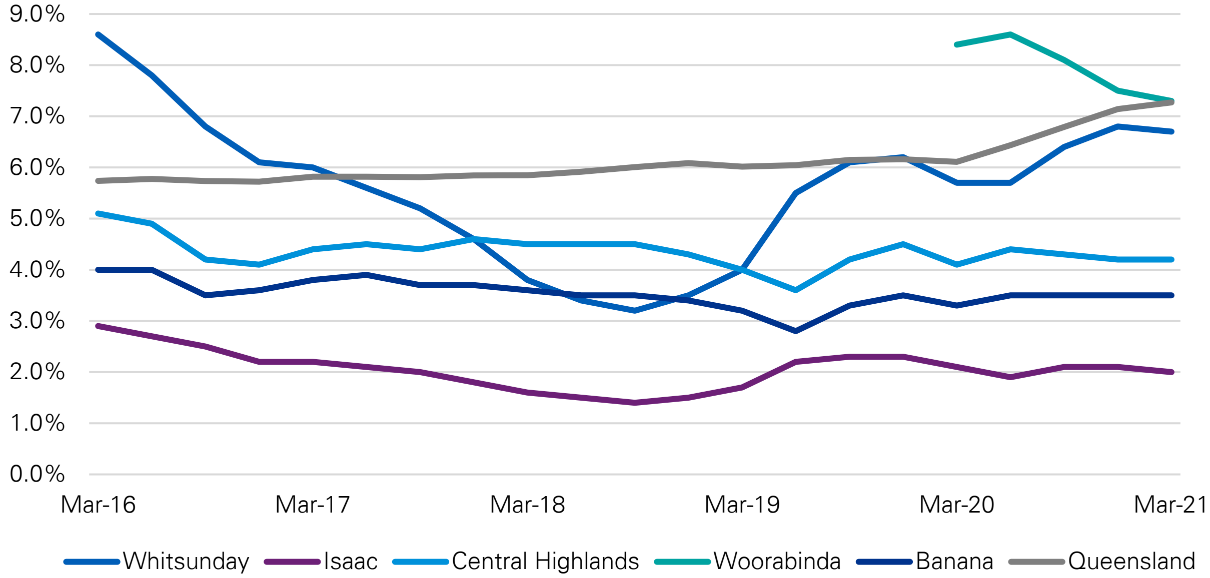
Table 43 - Summary of labour force characteristics, March 2021.

	Labour force	Participation rate*	Unemployed persons	Unemployment rate	12 month unemployment rate Δ
Whitsunday	21,366	66.7%	1,425	6.7%	1.0pp
Isaac	12,987	76.6%	264	2.0%	-0.1pp
Central Highlands	17,131	77.7%	717	4.2%	0.1pp
Woorabinda	592	87.2%	43	7.3%	-1.1pp
Banana	8,412	74.8%	297	3.5%	0.2pp
Study area	**60,488**	**73.1%**	**2,746**	**4.5%**	**0.4pp**
Queensland	*2,713,872*	*52.1%*	*197,348*	*7.3%*	*1.2pp*

**Participation rate for working age population 15 years and older as at June 2019.*

Sources: Australian Government's Small Area Labour Markets (SALM) publication, March Quarter 2021; ABS, 3235.0 Regional Population by Age and Sex, Australia, June 2019.

Figure 106 - Unemployment rate.



Note: Data is not available for Woorabinda prior to March 2020.

Source: National Skills Commission. 2021. Small Area Labour Markets (SALM), March quarter 2021

Table 44 outlines employment statistics for subsets of the population as of the 2016 Census. Across the study area, 65.0% of residents aged 15 to 24 years old) participate in the labour market, comparable to the overall total participation rate (64.7%). Both the youth and total participation rates are higher for the study area than for Queensland (64.4% and 61.0%, respectively). Woorabinda has a particularly low youth participation rate (23.3%).

The youth unemployment rate of the study area (10.0%) was higher than the overall total unemployment rate (5.6%), with Woorabinda having the highest rate (33.3%). The study area's youth unemployment rate was lower than the Queensland average (15.8%).

Across the study area, 57.5% of First Nations people participated in the labour market, below the overall total participation rate (64.7%). The study area's participation rate was higher than the Queensland average (54.7%). Isaac has the highest participation rate (72.7%) while Woorabinda has the lowest (32.9%).

The study area's Indigenous unemployment rate (16.2%) was much higher than the overall total rate (5.6%). However, all LGAs from the study area had a lower Indigenous unemployment rate than the Queensland average (20.1%).

Table 44 - Labour market subsets, 2016 Census.

	Youth Labour Market		Indigenous Labour Market		Total Labour Market	
	Participation rate	Unemploy-ment rate	Participation rate	Unemploy-ment rate	Participation rate	Unemploy-ment rate
Whitsunday	65.0%	9.5%	60.0%	19.1%	60.7%	6.7%
Isaac	63.6%	9.5%	72.7%	10.0%	67.1%	4.9%
C Highlands	66.2%	10.9%	62.5%	15.0%	67.5%	5.5%
Woorabinda	23.3%	33.3%	32.9%	19.2%	36.5%	17.2%
Banana	69.5%	9.0%	60.9%	17.0%	67.2%	4.0%
Study area	**65.0%**	**10.0%**	**57.5%**	**16.2%**	**64.7%**	**5.6%**

	Youth Labour Market		Indigenous Labour Market		Total Labour Market	
	Participation rate	Unemploy-ment rate	Participation rate	Unemploy-ment rate	Participation rate	Unemploy-ment rate
Queensland	*64.4%*	*15.8%*	*54.7%*	*20.1%*	*61.0%*	*7.6%*

**Participation rate for working age population 15 years and older as at 2016 Census*

Source: ABS, 2016 Census of Population and Housing.

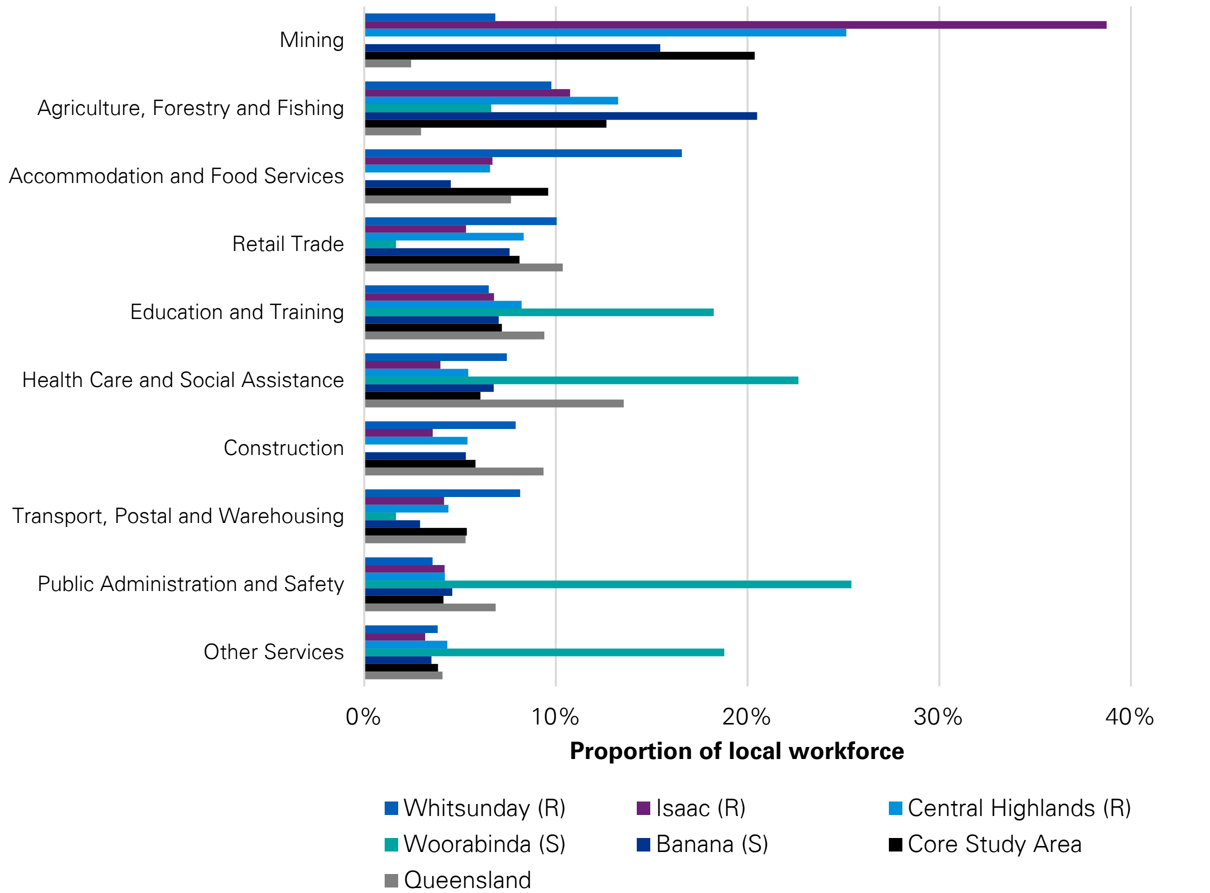
4. Industry (place of usual residence)

There were 98,000 workers who lived in the study area as of the 2016 Census. Whitsunday had the most (34.5%; 33,782 workers) while Woorabinda had the fewest (1.0%; 960 workers).

As demonstrated in Figure 107, the most common industry was Mining, employing approximately one in five workers across the study area (20.4%; 9,122 workers) and almost two in five workers in Isaac (38.7%; 3,759 workers) – far higher than the Queensland average (2.4%). Woorabinda does not employ any local residents in mining. Within the Mining industry, Coal Mining employs the vast majority of workers (8,309 workers), while Oil & Gas Extraction employs the fewest (95 workers).

Mining was followed by Agriculture, Forestry & Fishing (12.6%), Accommodation & Food Services (9.6%) and Retail Trade (8.1%) in terms of employment.

Figure 107 - Top ten industries by employment, place of usual residence, 2016 Census.



Note: Excludes the industry categories of Inadequately Described, Not Stated and Not Applicable. ABS does not separate out data for the tourism industry.

Source: ABS, 2016 Census of Population and Housing .

As at June 2016, there were a number of residents within the study area employed in industries directly relevant to the development of a gas pipeline. 5.8% were employed in the Construction industry (2,597 workers), which predominantly driven by the Construction Services subsector (1,588 workers), followed by Building Construction (501 workers) and Heavy & Civil Engineering Construction (381 workers).

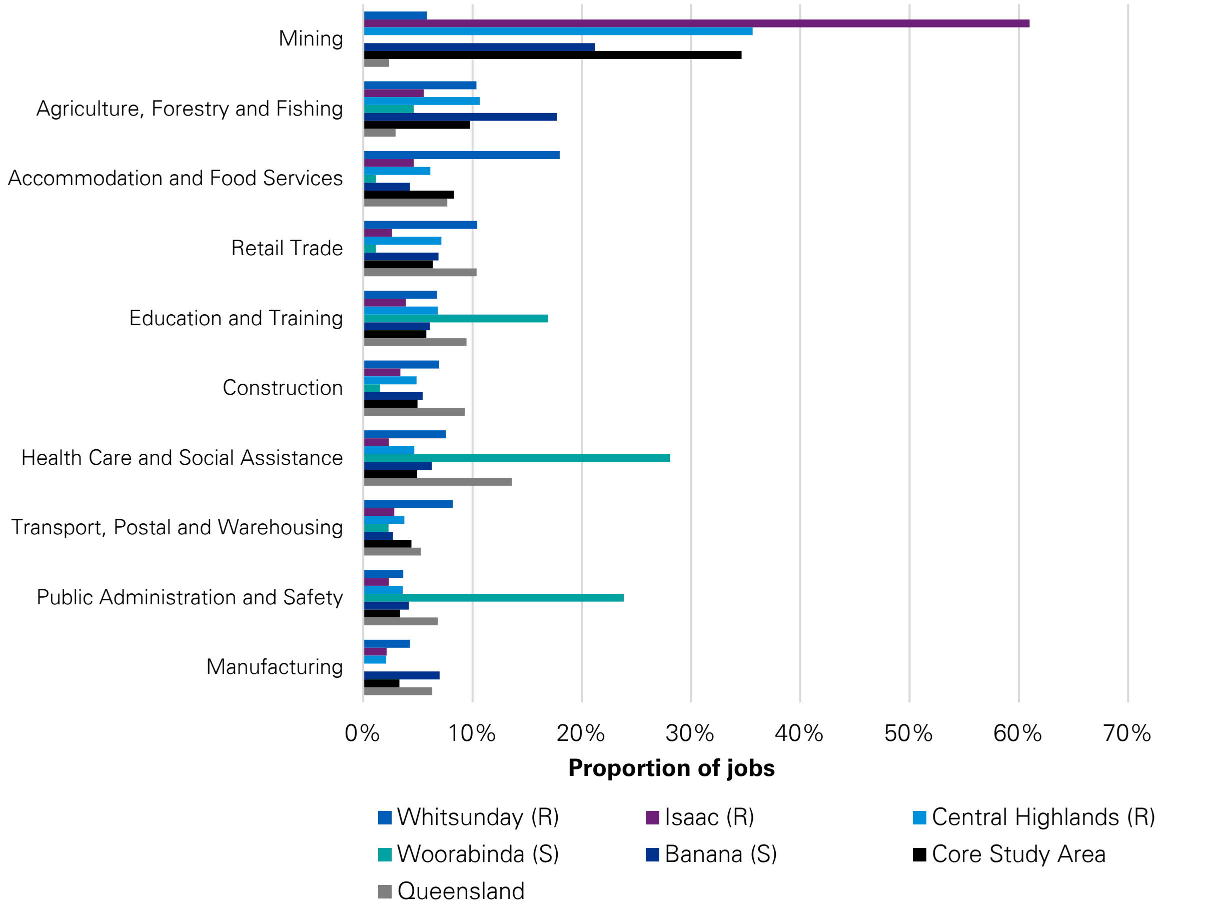
5. Industry (place of work)

There were 59,653 jobs (people who were employed) in the study area as of the 2016 Census. The largest proportion of these was in Isaac (33.6%; 20,034 jobs) and the smallest proportion was in Woorabinda (0.4%; 265 jobs).

As illustrated by Figure 108, the Mining industry represents the largest share of jobs across the study area (34.6%; 19,981 jobs), with three out of every five jobs in Isaac being in mining (61.0%; 11,919 jobs). Woorabinda does not have any mining jobs. Within the Mining industry, Coal Mining supports the vast majority of jobs (18,072 jobs), while Non-Metallic Mineral Mining & Quarrying supports the fewest (95 jobs). Oil & Gas Extraction accounts for 152 jobs across the study area.

Outside of Mining, jobs are predominantly supported by Agriculture, Forestry & Fishing (9.8%), Accommodation & Food Services (8.3%) and Retail Trade (6.4%).

Figure 108 - Top ten industries of employment, place of work, 2016 Census.



Note: Excludes the industry categories of Inadequately Described, Not Stated and Not Applicable. ABS does not separate out data for the tourism industry.

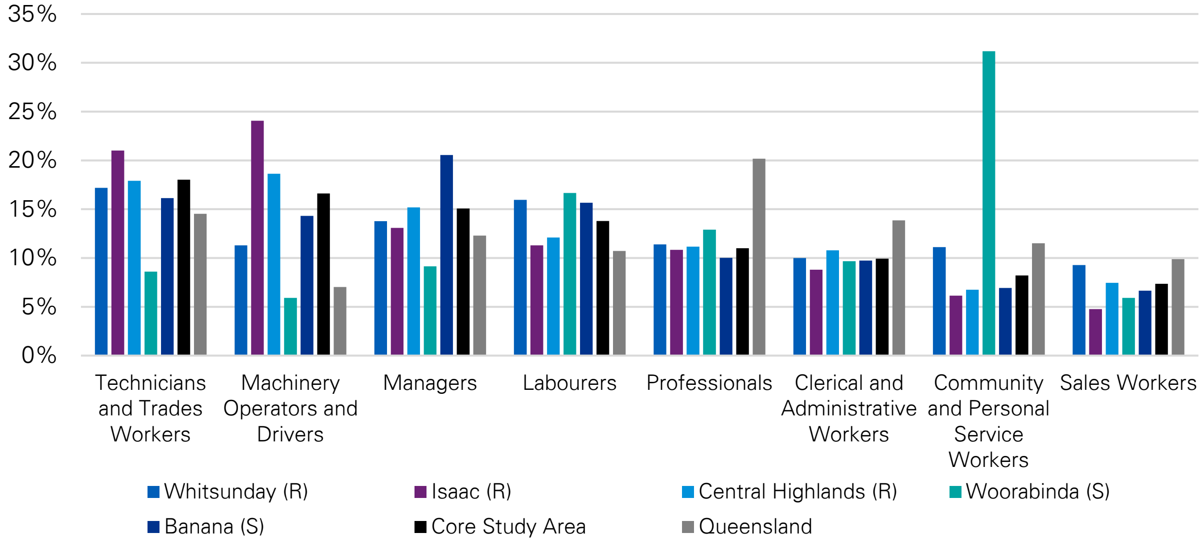
Source: ABS, 2016 Census of Population and Housing .

6. Occupation (place of usual residence)

As shown in Figure 109, Technicians & Trades Workers (18.0%) and Machinery Operators & Drivers (16.6%) were the most common occupations for residents of the study area, which is reflective of the Bowen Basin's high concentration of primary industry.

The study area had higher proportions of these occupations than the Queensland average (14.5% and 7.0%, respectively). This was mirrored in every individual LGA except for Woorabinda, which instead had a very large proportion of Community & Personal Service Workers (31.2%) – far higher than state and study area averages. The study area also had significantly lower proportions of Professionals and Clerical & Administrative Workers.

Figure 109 - Local workers' occupation (place of usual residence), 2016 Census.



Note: Excludes the occupation categories of Inadequately Described, Not Stated and Not Applicable.

Source: ABS 2016 Census of Population and Housing.

Appendix F: Recent Policy Reform

The following sections detail the key policy reform measures recently introduced that affect the functioning of the ECGM.

Australian Domestic Gas Security Mechanism (ADGSM)

In response to price increases during 2016 and 2017, the ADGSM was established as a temporary supply security measure to cease on January 1, 2023. The ADGSM is intended to ensure sufficient supply of natural gas to meet the forecast needs of energy users in Australia. It aims to do so by limiting exports of LNG during a domestic shortfall year and establishing a licensing regime whereby the Resources Minister may grant Export Permission to LNG exporters. Since the introduction of the ADGSM, LNG exporters have increased supply to the domestic market and are currently, in aggregate, net contributors to the domestic market.

A Government review in 2020 recommended retaining the ADGSM until the scheduled 2023 cessation, amending the guidelines to include reference to the ACCC's LNG netback price series in estimating a potential shortfall. This stops short of introducing direct price controls in the ECGM, but it does link the ADGSM to LNG netback prices.

Heads of Agreement

On two occasions, a Heads of Agreement (HoA) has been signed by the Australian Prime Minister and representatives of the three east coast LNG exporters (APLNG, GLNG, QGC) to ensure these producers make available a secure supply of gas to the east coast market. Under the agreement, LNG exporters committed to offer uncontracted gas to the domestic market before selling this gas internationally. The HoA expired at the end of 2020 with a new one signed in January 2021. The Australian Government has said it wants to 'strengthen' the HoA with east coast LNG exporters and include a reference to LNG netback pricing.

Domestic Gas Reservation Scheme

Whilst the ADGSM functions somewhat as a domestic gas reservation scheme, the Australian Federal Government has announced its intention to explore options for a national domestic gas reservation scheme. This may take the form of acreage reservation, preferential reservation, blanket reservations or case-by-case assessments. As the states hold jurisdiction over onshore petroleum resources, any Federal Government scheme would need to be implemented with support of the states. There is no national domestic reservation scheme in Australia at the moment, however there are existing schemes that utilise different approaches across various states, particularly in Queensland and Western Australia.

Queensland

Through its regulation of petroleum leases, the Queensland Government imposes a condition on certain tenements that any petroleum developed on the leased acreage must be sold and used only in Australia. Recently, the Queensland Government included a specific requirement for gas produced to be supplied to domestic manufacturing consumers. This approach will not impact the market materially because it will just displace existing supply to these consumers.

The Queensland Government commissioned an independent review of this policy in 2019. The final report released in February 2020 found that stakeholders broadly accepted the policy but noted there was room for improvement around adaptability, efficiency and transparency, and provision of information to market participants.

Western Australia

Western Australia adopts a policy that requires LNG producers to reserve the equivalent of 15% of LNG production for the domestic market. LNG producers can obtain project approval by proving they will reserve gas for the market, develop the necessary infrastructure, and show diligence and good faith in marketing the gas. The policy has been in place for a number of years and is flexible with respect to exact timing, price, and sale conditions.

We understand that the Western Australian domestic gas reservation policy has been relatively successful in terms of supporting the domestic market and not being a significant impost on LNG producers. One of the reasons for this is that in Western Australia the natural gas industry is predominately offshore, with conventional wells extracting large reserves of gas and without the complications of CSG production. The Western Australian Government and the projects negotiate timing for domestic gas flows in a way that meets the objectives of the domestic market and LNG exporters.

Queensland Petroleum Royalty Review

The Queensland Government announced major changes to how petroleum royalties will be calculated from October 1, 2020. Under the review, royalties are now calculated based on applying a tiered royalty rate to the volume of petroleum produced for each class of gas, rather than the previous system of 12.5% of wellhead value of petroleum disposed. The change was in response to producers and industry participants voicing concerns about the complexity of the prior regime and successful court challenges to a previous royalty decision. A different royalty rate will be prescribed for each petroleum classification and will remain unchanged for five years. The royalty changes may have implications for existing contracts which may have anticipated the wellhead value model continuing.

Gas Fired Recovery

The Australian Federal Government announced a ‘Gas-Fired Recovery’ scheme in September 2020 as part of the COVID-19 economic recovery plan. One objective of the scheme is to increase the supply of gas in the market by setting new gas supply targets with states and territories and unlocking five key gas basins in the Northern Territory and Queensland at a cost of $28.3M. The Government is also considering a reservation scheme to secure future gas supplies for domestic consumption only. A $10.9M National Gas Infrastructure Plan has been proposed to identify priority pipelines and infrastructure. The intention is to deliver more gas at an affordable and internationally competitive price. Prime Minister Scott Morrison stated that, “affordable gas will play a central role in re-establishing the strong economy we need for jobs growth, funding government services and opportunities for all”.

Industry bodies have raised concern over the proposed scheme. Australian Petroleum Production & Exploration Association (APPEA) chief executive Andrew McConville said, “caution is needed when considering any regulatory interventions that could risk the attractiveness of Australia as an investment destination for oil and gas projects – these projects are essential for shoring up Australia's future gas supplies”.

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