REPORT TO
DEPARTMENT OF THE ENVIRONMENT AND ENERGY
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WEST–EAST PIPELINE PRE-FEASIBILITY STUDY

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EXECUTIVE SUMMARY: KEY FINDINGS AND RECOMMENDATIONS

A West–East Pipeline represents a technically feasible option for increasing gas supply to the Eastern States of Australia. However, commercial and market risks present major challenges for the project.

To proceed, the project would need to secure sufficient long-term commitments on the part of both gas producers and gas buyers to de-risk the project and make it financeable. This alignment of sellers and buyers would need to be achieved in an environment of considerable market uncertainty. Such uncertainty is not conducive to making long-term contractual commitments. Achieving the necessary buy-in would also need to occur despite the potential emergence of new competitive sources of gas which are closer to the Eastern Australian market and could present buyers with more compelling alternatives. Market modelling indicates that strong uptake of gas delivered via the pipeline would be unlikely to occur for around ten years, and that this could be further delayed if significant new sources of supply emerge nearer to market.

On this basis, the West–East Pipeline does not currently appear to be the best or most economical option for dealing with the supply issues currently facing the gas market in Eastern Australia.

Problem diagnosis

Eastern Australia faces a short-term gas supply problem and may face a long-term gas supply problem.

The short-term problem is that, owing to a lack of competitive gas supply alternatives, gas consumers in south-eastern Australia are at present facing sharply rising prices. Some large gas users have been reporting difficulties in securing gas supply offers at any price. This problem has been particularly apparent in Victoria and Tasmania, and to a lesser extent in South Australia and New South Wales. Constrained gas supply and rising gas demand in the electricity generation sector also leads to a short-term risk of physical supply shortfalls that could result in curtailment of gas deliveries to some customers.

The potential long-term problem facing the Eastern Australian gas market is one of insufficient reserves replacement. Put simply, there may not be enough new reserves of gas discovered and brought into production in Eastern Australia to replace declining reserves in developed fields.

The large LNG export plants at Gladstone have tripled total gas demand in Eastern Australia. Their development was based on a major expansion of coal seam gas (CSG) production in Queensland, together with some contracted supplies of gas from third-party producers of CSG and conventional gas. While this rapid expansion of regional gas production directed toward the export LNG industry has been going on, there has been relatively little activity aimed at finding new replacement sources of supply from the areas that have traditionally served the domestic market. A combination of lower oil prices and restrictive State and Territory government policies on oil and gas exploration and production has seen a steep decline in investment aimed at bringing on new domestic supply. This has occurred despite market signals that have been evident for some years.

Dealing with the problems

The short-term problem facing the Eastern Australian gas market requires solutions that can be deployed quickly and that, ideally, can be unwound if better long-term structural solutions are found.

The West–East Pipeline cannot address the short-term problem because it is a long-term solution, with a long lead time. It would take several years to complete the necessary planning, approvals, route acquisition, commercial agreements, procurement and construction processes ahead of the first gas delivery via a West–East Pipeline. The project would involve a large capital investment—more than $5 billion for the pipeline and associated facilities alone—with a long pay-back period. The pipeline would be a long-term solution not well-suited to dealing with short-term and possibly transient problems.

The most likely solutions to the immediate problem of high prices and constrained supply will be a combination of new incremental supply from established production regions such as Bass Strait, together with some re-direction of gas from the Queensland LNG projects into the domestic market.

There are several alternatives for dealing with the potential long-term problem of insufficient reserves replacement. The West–East Pipeline offers one such solution. There are several other options, including new conventional gas fields in the Gippsland, Bass, Otway and Cooper Basin areas; shale gas developments in the Northern Territory supported by new pipeline investment; tight gas developments in the Cooper Basin; CSG developments in New South Wales and Queensland; and LNG imports.

All these new supply options face challenges and none is assured. Whether or not they will, individually or collectively, be able to fully address the looming gas supply gap in Eastern Australia remains to be seen.

The West–East Pipeline faces major challenges that will be difficult to overcome, particularly while other, lower cost and more flexible options remain in prospect. However, if these alternatives do not emerge in time to secure long-term gas supply for the Eastern States, the West–East Pipeline could emerge as the best available option to do so. It would be premature to commit to development of the West–East Pipeline now, but it would make sense to keep the option open unless and until alternative solutions emerge.

Stakeholder engagement

As part of the pre-feasibility study process, ACIL Allen and GHD consulted with key stakeholders, including state and territory governments, gas producers, pipeline operators and major gas users to inform the study findings.

Five key themes emerged across the issues and challenges raised by stakeholders:

- Market-related risks
- Sources of gas supply
- The role for Government
- Regulatory risks
- Routing considerations

Across all stakeholder groups, **market risks** were seen to be the greatest challenge for the project.

The potential emergence of competing sources of gas supply closer to the Eastern Australian demand centres was seen to be a key risk, with several alternatives identified including new conventional and unconventional gas fields and LNG imports.

Stakeholders thought that long-term take-or-pay style contracts could ameliorate the commercial risks faced by gas producers and pipeline owners committing to the project, but they were generally sceptical regarding the appetite of purchasers to enter into such long-term contracts. Most thought that the project would need 20-year contract commitments, but that buyers would not be willing to take on such long-term risks.

Uncertainty over long-term demand for natural gas and the potential for increased levels of fuel substitution were raised as factors that would make gas buyers wary of locking into large-volume, long-term supply contracts.

There was also a concern that the potential exit of some large commercial and industrial (C&I) customers could relieve the current supply tightness in the market and see local gas prices fall, thereby eroding the opportunity for the pipeline.

Potential buyers indicated that they would need to see low prices (one suggested around $7.50/GJ ex Moomba) to be interested in contracting with the pipeline, but that even then they would be unlikely to commit for more than about five years.

Regarding sources of **gas supply**, stakeholders in Western Australia expressed concerns about the adequacy of domestic gas supply in their own State beyond the mid-2020s, pointing to an expected reduction in domestic gas supply from the North West Shelf. Producers noted that exploration activity has fallen to very low levels; they thought that a new source or multiple sources of supply would need to be developed to provide feed gas for a West–East Pipeline. There was no appetite to divert gas from existing fields away from LNG or outside of the Western Australian domestic market.

Stakeholders pointed to large stranded gas resources in the north-west but thought development of fields in the Browse Basin would be very challenging, requiring the simultaneous development of pipeline infrastructure and a major offshore development.

Producer comments indicated that gas price of around $6/GJ for supply into the pipeline was a reasonable expectation.

Several stakeholders pointed to the risk to the pipeline posed by new sources of supply in the Northern Territory and the Eastern States, particularly if current restrictive policies were changed. The Beetaloo Basin in the Northern Territory was seen to have strong prospects and a potentially more competitive source of supply that would undercut the economics of a West–East Pipeline. They thought that, if the current moratorium on hydraulic fracturing of shale gas in the Northern Territory was lifted, gas supply from the Beetaloo Basin could make a West-East Pipeline non-viable.

– In April 2018, shortly after the completion of this pre-feasibility study, the Northern Territory Government announced the lifting of the moratorium on hydraulic fracturing. As a result, exploration for shale gas in the Beetaloo Sub-basin of the McArthur Basin is expected to resume, subject to strict operational and environmental controls. The implications of the lifting of the moratorium are further discussed in **Attachment H**.

Several stakeholders commented that if the case for the pipeline stacked up commercially it would have already happened, indicating that the project was likely to need government support. It was suggested that such support could come in the form of exploration incentives, up-front funding contributions, taking on demand risk with a long term take-or-pay contract, or tariff subsidy. Government ownership or equity participation was not generally seen as a desirable outcome.

It was noted that government backing for the West–East Pipeline could create disincentives for current and future domestic gas exploration by introducing a large supply source that would dominate the market. It was suggested that government support in the form of long-term take-or-pay commitments could lead to reduced levels of domestic gas exploration on the east coast. Past examples that were mentioned included Western Australian government support for the Dampier-Bunbury Natural Gas Pipeline (through a long-term State Electricity Commission WA contract) and New Zealand Government support for development of the Maui Pipeline through a long-term, large volume Crown contract. In both cases, government commitment to the projects was followed by long periods in which there was little exploration for alternative or replacement sources of domestic gas, leading to periods of tight supply and high prices toward the end of the contracts.

The **regulatory risks** raised by stakeholders included native title, environmental approvals, economic regulation and gas market reform policies, renewable energy policies, restrictive exploration and production policies, and gas reservation policies.

On the matter of **alternative pipeline routes**, most stakeholders supported examination of the identified offtake points (in the south near Dampier, in the north near Broome) and delivery points (Moomba, Adelaide). Most stakeholders regarded Moomba as more likely to provide a viable route alternative because it would maximise market access, particularly for the large Gladstone LNG loads. A Moomba terminus was also seen to offer advantages through access to existing processing, compression and underground storage facilities.

Some stakeholders suggested that other route alternatives should be considered, including routes further north, through the Amadeus Basin to Moomba, and to the head of the Northern Gas Pipeline at Tennant Creek.

While stakeholders generally saw the merit in considering mid-line opportunities, they did not see them as being primary drivers of the project. Some stakeholders identified mid-line opportunities to service areas of known mineral and petroleum resource potential as well as existing mines. Geoscience Australia has comprehensive databases on mineral occurrences and prospectivity, as well as web portal tools that could be of considerable assistance in the evaluation of route options and identification of mid-line development opportunities that could benefit from access to energy.

On the matter of route alignment and access issues, several stakeholders identified the lead times associated with gaining land access as critical issues for project timing, with native title claims seen to be the most significant route consideration in terms of potential impact on timing.

Market modelling

Detailed market assessments were undertaken for four route options:

— Route 1 – Dampier (Carnarvon Basin) to Moomba
— Route 2 – Dampier (Carnarvon Basin) to Adelaide
— Route 3 – Broome (Browse & Canning Basins) to Moomba
— Route 4 – Broome (Browse & Canning Basins) to Adelaide

Two other route alternatives were also tested, but were not modelled in depth because they were found to result in lower levels of utilisation, making them less likely to be commercially viable:

— A Northern Route in which the West–East Pipeline is built from Dampier to Tennant Creek, linking up with the Northern Gas Pipeline.
— A 'Moomba via Amadeus' route in which the West–East Pipeline is built from Dampier to the Amadeus Basin in the Northern Territory, linking up with a Southern NT Pipeline (SNP) linking the Amadeus Basin to Moomba.

For each route option, ACIL Allen's *GasMark®* model was used to assess the ability of WA gas, delivered via the West–East Pipeline, to penetrate the Eastern Australian market.

For each of these alternative routes, annual flows on the West–East Pipeline were modelled over a range of assumed gas feed prices, from $2/GJ to $10/GJ at $1/GJ steps, to assess market penetration. The market penetration profiles were then used, in combination with the capital and operating cost estimates prepared by GHD, to refine the pipeline design, costings and estimates of commercially sustainable pipeline tariffs.

Our analysis indicates that it would be reasonable to assume a producer selling price, in current dollar terms, of between $5 and $6/GJ into pipe. This is consistent with stakeholder feedback.

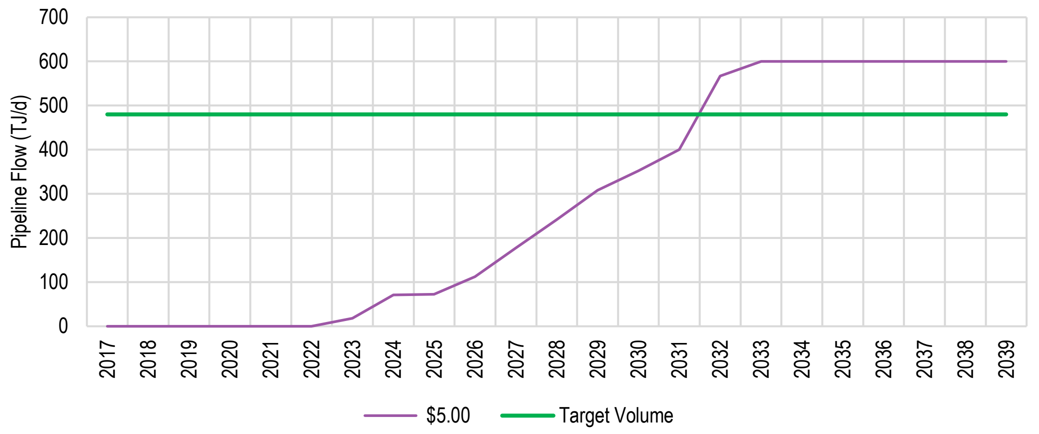
The modelling demonstrated that if the gas supply to support the West–East Pipeline was also connected to, and free to trade in, the Western Australian domestic market, a large part of the incremental supply would be taken up in Western Australia where it would displace more expensive gas supply alternatives. On this basis, the West–East Pipeline would not achieve the critical mass of market support required to make the pipeline viable. To avoid this problem, the gas supply to the West–East Pipeline would need to be physically or contractually dedicated to the project, effectively quarantining it from the Western Australian domestic market. The gas supply would also need to come from new processing capacity built for the purpose; there is insufficient 'spare' domestic gas processing capacity in Western Australia to allow the supply to be taken from existing facilities without adversely affecting supply security and price in the local market.

Comparison of the market penetration results for Routes 1 to 4 showed that the routes terminating at Moomba (Routes 1 and 3) would achieve target rates of market penetration more quickly than the

Adelaide-terminating routes. Because of the very significant co-ordination and alignment risks in relation to Browse/Canning Basin gas supply, Pipeline Route 1 (Dampier – Moomba) was selected as the currently preferred route alignment (see detailed modelling in Section 4.4.3).

Figure ES 1 shows the modelled gas flows through the West–East Pipeline to Eastern Australia for Route 1 (Dampier to Moomba), assuming gas supply into pipe at $5/GJ (real, 2017 dollar terms) and no opportunity to divert this gas supply to the WA domestic market. Flows ramp up over a period of around ten years, reaching the targeted annual throughput of 480 TJ/d average (600 TJ/d maximum capacity at 80 per load factor) in 2032.

FIGURE ES 1 MODELLED GAS FLOWS ON THE WEST–EAST PIPELINE FOR ROUTE 1 (DAMPIER TO MOOMBA), $5/GJ GAS SUPPLY TO PIPE, NO WA DOMESTIC CONNECTION



SOURCE: ACIL ALLEN GASMARK MODELLING

This slow ramp up of throughput is likely to present a major challenge in securing shipper contracts for the full capacity of the pipeline.

To assess the effects of the pipeline on gas prices and consumption in the Eastern Australian and Western Australian markets, the results for the various route options were compared with a Reference Case with no West–East Pipeline connection.

Whether or not the dedication of around 4,000 PJ of reserves to interstate exports via the West–East Pipeline will have any negative effect on Western Australian gas supply and prices was found to depend on where those reserves come from: some sources resulted in little or no price impact whereas others affected modelled prices.

The modelling found that, whereas initially much of the throughput on the West–East Pipeline is directed into New South Wales via the Moomba–Sydney Pipeline, the proportion of deliveries reporting to the South West Queensland Pipeline system increases over time. By the end of the modelling period, virtually all the gas carried on the West–East Pipeline is delivered into Queensland with much of it taken up in the Gladstone LNG plants, displacing high marginal cost CSG production.

The West–East Pipeline imports resulted in modestly higher levels of gas consumption—up to about 8 PJ/a above the Reference Case consumption level of about 550 PJ/a. Most of the Western Australian gas displaced higher cost Queensland CSG, deferring production of those resources to a later date. Significant consumption effects were confined to the post-2030 period. The consumption impacts of all four route options were similar.

Even though much of the gas carried by the West–East Pipeline was found to end up in the Gladstone LNG plants, benefits were felt throughout the Eastern Australian domestic market in terms of lower wholesale gas prices. Increased gas supply was found to relieve production pressure on Eastern Australian sources, allowing production of high-cost marginal CSG to be deferred. The extent of price reductions varied at different locations throughout Eastern Australia, ranging from as much as $3.50/GJ below the Reference Case price in Melbourne to around $1/GJ lower in Brisbane.

Testing the sensitivity of the market penetration results to Eastern Australian LNG imports showed that an LNG import terminal located in Victoria would suppress flows on the West–East Pipeline for some time but would not necessarily be fatal to the project. There could eventually be room in the market for both an LNG import terminal and the West–East Pipeline. If both LNG import terminals[1] currently proposed for Eastern Australia were to proceed, the market opportunity for the West–East Pipeline would be further deferred and reduced.

Potential returns on investment: the critical importance of contracted capacity and timing

The modelling indicates that the West–East Pipeline could achieve a pre-tax real rate of return of 8 per cent by constructing and operating the pipeline following the Route 1 alignment from Dampier to Moomba and charging shippers a tariff of $2.91/GJ (real 2017 dollar terms). That finding is, however, subject to critically important assumptions about the level of contracted capacity on the pipeline and the timing of capital outlays relative to the timing of tariff revenues. Specifically, it assumes that:

— shippers would contract and pay for all the capacity in the pipeline (600 TJ/d) on a firm capacity basis.

— payment for the full contracted capacity would commence in the year after completion of construction.

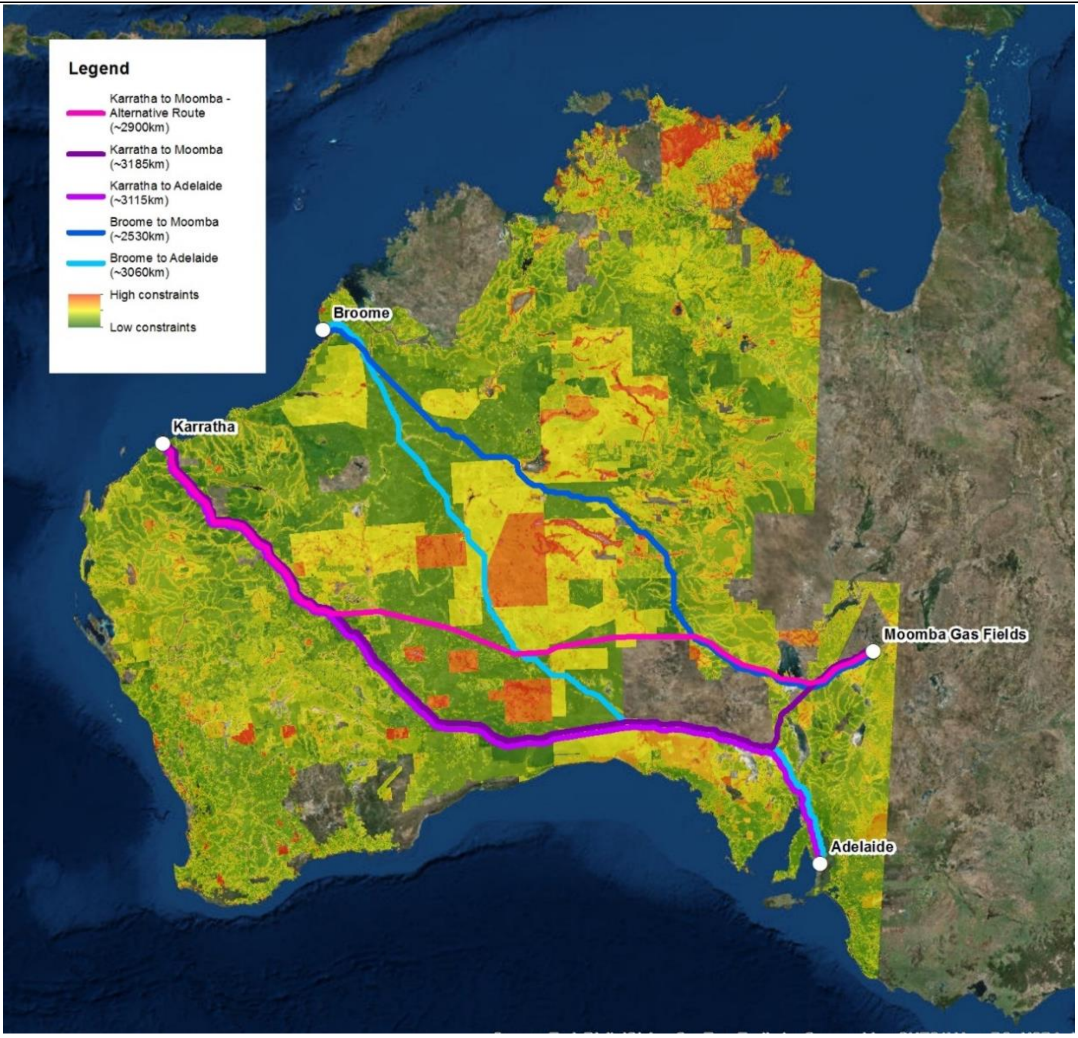
If shippers agree to pay only for gas actually shipped, so that revenues follow the ramp-up profile shown in **Figure ES 1**, the unit tariff would need to rise from $2.91/GJ to $5.35/GJ, with no loss of throughput volume, in order to achieve an 8 per cent rate of return. The modelling shows that an increase of $2 to $3/GJ in the cost of gas would defer the ramp-up of gas throughput by 4 to 5 years, further damaging the project economics and requiring an even higher tariff to achieve targeted rates of return. The economics of the project would therefore be severely impacted by pre-emptive investment in the pipeline ahead of the establishment of a firm foundation customer tariff revenue stream.

Route assessment and design

Infrastructure Development Geospatial Options (InDeGO)—a multi-criteria assessment and route selection approach developed by GHD to scientifically and mathematically identify potential and optimum routes for linear infrastructure developments—was used to assess the potential pipeline route options to deliver gas from Western Australia to the east coast gas market. The InDeGO model was used to identify four optimised routes that represent the least-cost combination of constraints and distance based on the criteria used for the analysis. The resulting indicative pipeline routes are shown in **Figure ES 2**.

[1] AGL is proposing to build an LNG import terminal in Victoria; an international consortium is investigating construction of a similar LNG import terminal in New South Wales.

FIGURE ES 2 OPTIMAL ALIGNMENTS FOR ALTERNATIVE WEST–EAST PIPELINE ROUTES



SOURCE: GHD INDEGO MODELLING

Further work is required to optimise the route alignments. The current routes are far longer than they would be if the weighting on national and state parks was lower. For example, on preferred Route 1 (2,900 km), a more direct route passing through small sections of state park could reduce total route length by between 200 and 300 km.

Several route selection issues were identified for further consideration if more detailed feasibility studies of the West–East Pipeline are undertaken in the future.

Approvals

The West–East Pipeline will fall within the legal jurisdictions of the Commonwealth and the States/Territories of Western Australia, South Australia and potentially the Northern Territory, depending on the chosen route alignment.

Chapter 5 of the report includes a review of the key approval requirements under Commonwealth and State/Territory legislation, and the associated approvals time frames.

Pipeline conceptual design

Based on a comparison of modelled rates of market penetration as well as stakeholder feedback, Route 1 was identified as being currently the most prospective route. Detailed assessment was therefore confined to that route. The overall commercial metrics for the other route options are likely to be broadly similar, but somewhat inferior, to those for Route 1.

The selected pipeline conceptual design was achieved by determining the diameter of pipeline and number of compressor stations required to transport the nominated volume of gas (up to 600 TJ/d) from the nominated inlet point (Dampier) to the delivery point (Moomba). Nominal pipeline diameters ranging from 24 inches to 36 inches were considered. The large diameter pipelines have lower mid-line compression requirements. As a result, there is a trade-off between pipeline and compressor capital costs, with the cost of compressor operation (principally fuel gas) a further consideration.

Cost estimation

GHD estimated pipeline construction costs, compressor costs and fuel gas requirements for each of the conceptual pipeline designs for Route 1, ranging from 24 to 36-inch diameter.

The 26-inch case was selected for further analysis because it provided the lowest whole-of-life cost, taking into consideration both the upfront capital cost and on-going cost of compressor fuel gas and maintenance.

The total capital cost for this case (Route 1; 2,900 km; 26-inch diameter, five compressor stations) was estimated to be around $5,800 million, including compressor capital costs of $550 million.

Operating and maintenance costs were estimated to be:

— Pipeline operating and maintenance cost: 1.25% of pipeline capital cost
— Compressor station operating and maintenance cost (excluding cost of fuel gas): 5% of compressor capital cost.

Fuel gas usage, based on an annual load factor of 80 per cent, is estimated at approximately 4 per cent of annual throughput—about $35 million per year with the pipeline operating at full capacity, assuming a fuel gas commodity cost of $5/GJ.

Project schedule

The estimated period required to complete feasibility studies and other activities required to reach a final investment decision is approximately 2 years.

The project execution phase, which includes obtaining all necessary approvals and agreements as well as detailed engineering and design, procurement, construction and commissioning could be expected to take a further 4 to 5 years.

By utilising four construction spreads, a 2,900 km pipeline could be constructed in around 22 to 26 months, subject to weather windows.

Labour requirements for a four-spread construction program would average around 900 personnel, with a maximum of approximately 1,300 workers. The majority of the construction workers would be expected to come from Western Australia, with the balance mainly from interstate Australia.

Preliminary risk evaluation

The technical risks associated with the project—routing, approvals, design, construction and delivery—can be largely mitigated using conventional project management strategies that are well established and proven. These are not seen as a barrier to the project proceeding.

The commercial and market risks present major challenges. For the project to proceed, it would be necessary to secure sufficient long-term commitment on the part of both gas producers and gas buyers to de-risk the project and make it financeable. This alignment of sellers and buyers would need to be achieved in an environment of considerable market uncertainty that is not generally conducive to entering into long-term contractual commitments. Achieving the necessary buy-in would also need to occur despite the potential emergence of new competitive sources of gas which are closer to the Eastern Australian market and could present buyers with more compelling value alternatives.

If the commercial and market challenges outlined above can be overcome, construction of the project could deliver significant security of supply benefits to the Eastern Australian market. It could provide regional development opportunities by helping to unlock otherwise stranded mineral and energy resources located near the pipeline route. Such opportunities should be further investigated during any future feasibility studies.

The market analysis demonstrates that while the West–East Pipeline could eventually the achieve the levels of penetration of the Eastern Australian gas market required to make the project commercially viable, that is unlikely to occur for at least ten years. In the meantime, other competitive supply alternatives may emerge that would further delay or eliminate the market opportunity for the West–East Pipeline. Therefore, rather than making any costly pre-emptive commitments, the Government should keep the various options under surveillance, and should take (or encourage) whatever prudent, low-cost steps it can to maintain the West–East Pipeline as a viable option to meet any future severe and sustained gas supply shortage in Eastern Australia. Major financial commitments to the project should only be made if and when it emerges that the West–East Pipeline is likely to provide the best, least-cost means of meeting the long-term needs of gas users and improving energy security in Eastern Australia.

Cost-benefit analysis

Comparison of the potential discounted costs and benefits of the project show that, from the perspective of the pipeline owners, the project under the assumptions employed for the Route 1 option from Dampier to Moomba would yield an IRR of 8 per cent on a real, pre-tax basis over a 30-year life. At any higher commercial rate of return target, the NPV of the project would be less than zero (in other words the target rate of return would not be achieved).

From the perspective of east coast gas users, the project potentially yields significant net benefits. The estimated total net benefits of gas cost savings over an eighteen-year period range between $3,656 million (10 per cent discount rate) and $8,613 million (3 per cent discount rate) depending upon the assumptions. On an annualised basis, the estimated net benefits would range between $203 million and $479 million per year depending on the assumptions.

Economic impact analysis

Computable general equilibrium (CGE) modelling of the West–East Pipeline (Route 1 option) was undertaken to complement and extend the cost benefit analysis, and to provide a better indication of the nation building potential of the project.

In terms of real economic output, for Western Australia the project sees increases in gross state product (GSP) that are broadly in line with the projected value of production, with the operations phase being where the key benefits of the project will be realised. The benefits to the Western Australian economy during the construction phase are smaller, with the project increasing demand for scarce factors of production and having a relatively modest positive effect on economic output when compared to the size of the investment.

However, the additional construction activity associated with the project has a noticeable effect on the real income of residents in Western Australia as there is increased demand for labour and goods and services which boosts local incomes relative to the Base Case. During the operations phase, the projected increase in real incomes in Western Australia is less than the projected increase in real economic output. This is because, although the gas production is happening in Western Australia, the taxes and profits are more widely distributed.

In Eastern Australia, the replacement of gas produced from more marginal fields with cheaper gas imports from Western Australia frees up scarce factors of production and, combined with the reduction in gas prices which improves the competitiveness of Eastern Australian industries, allows Eastern Australia to increase output from alternative industries. In net terms, the price benefit over the period 2026-2039 is projected to more than offset the crowding out of reduced gas production in the Eastern States, leading to a net increase in real economic output over this period.

There is a large jump in the real economic output of Eastern Australia in the last few years of the projection period (2036-2039) because the deferral of local production brought about by Western Australian gas imports extends the economic life of the Gladstone LNG facilities.

Over the period 2018 to 2039, the construction and operation of the West–East Pipeline under the Route 1 option is projected to increase the **real economic output** of:

- *Western Australia* by a cumulative total of $16.0 billion relative to the Base Case (with a net present value of $6.0 billion, using a 7 per cent real discount rate)
  - $805 million of the projected benefit occurs during the construction phase with the remainder spread during the modelled operations phase
- *Eastern Australia* as a whole by a cumulative total of $10.0 billion relative to the Base Case (with a net present value of $3.0 billion, using a 7 per cent real discount rate)
  - $273 million of the projected benefit occurs during the construction phase with the remainder spread during the modelled operations phase.
- *Australia* as a whole by a cumulative total of $26.0 billion relative to the Base Case (with a net present value of $9.0 billion, using a 7 per cent real discount rate)

To place the projected changes in economic output estimates in perspective, the discounted present value (using a 7 per cent discount rate) is equivalent to 2.4 per cent of Western Australia's current GSP and 0.5 per cent of Australia's current GDP.

The corresponding impact on **real incomes** sees increases of:

- *Western Australia* by a cumulative total of $1.7 billion, relative to the Base Case (with a net present value of $1.2 billion, using a 7 per cent real discount rate)
  - $1.3 billion of the projected benefit occurs during the construction phase with the remainder spread during the modelled operations phase
- *Eastern Australia* as a whole by a cumulative total of $15.9 billion, relative to the Base Case (with a net present value of $5.0 billion, using a 7 per cent real discount rate)
  - $313 million of the projected benefit occurs during the construction phase with the remainder during the modelled operations phase.
- *Australia* as a whole by a cumulative total of $17.5 billion, relative to the Base Case (with a net present value of $6.2 billion, using a 7 per cent real discount rate)

To place these projected changes in income in perspective, the discounted present values (using a 7 per cent discount rate) are equivalent to a one-off increase in the average real income of all current residents of:

- *Western Australia* by approximately $462 per person
- *Australia* as a whole by approximately $250 per person.

In terms of **employment**, over the life of the West–East Pipeline it is projected that approximately 31,800 employee years[2] of full time equivalent (FTE) direct and indirect jobs will be created. The positive employment effects in Western Australia occur through the construction period; from 2025 on the pipeline results in an annual average of 268 fewer jobs in Western Australia because the restructuring of the Australian economy toward increased gas production in Western Australia and other activity in Eastern Australia creates a pull factor for labour away from Western Australia towards Eastern Australia.

In Eastern Australia, the modelling shows an increase of 750 employee years in total during the construction phase, and an increase of 31,222 employee years during the operational phase.

There is a significant increase in **average real wages** in Western Australia during the construction phase of the project. During the pre-production phase, real wages in Western Australia are projected to increase by an average of 0.2 per cent relative to the Base Case, with a peak of 0.5 per cent in 2020. Over the operations phase, real wages in Western Australia are projected to fall by an average of –0.02 per cent relative to the Base Case, while real wages in Eastern Australia increase by an average of 0.05 per cent. Given the size of the Eastern Australian labour market, this is a significant increase.

[2] An employee year is equivalent to the employment of 1 FTE person for one year. Alternatively, it can represent employment of, say, two full-time people for half a year each, or one 0.5 FTE person for two years.

The way forward: maintaining the West–East Pipeline option

The West–East Pipeline is not currently the best or most economical option for dealing with the issues currently facing the gas market in Eastern Australia. It is a long-term, fixed solution that cannot, in the short-term, mitigate the problems currently being faced by east coast gas users: constrained supply with limited competitive alternatives and sharply rising prices. Even in the long term, the West–East Pipeline faces major challenges that will be difficult to overcome, particularly while other, lower cost and more flexible options remain in prospect.

However, if these alternatives do not come to fruition in time to secure long-term gas supply for the Eastern States, the West–East Pipeline could emerge as the best available option. For this reason, it would make sense to keep that option open.

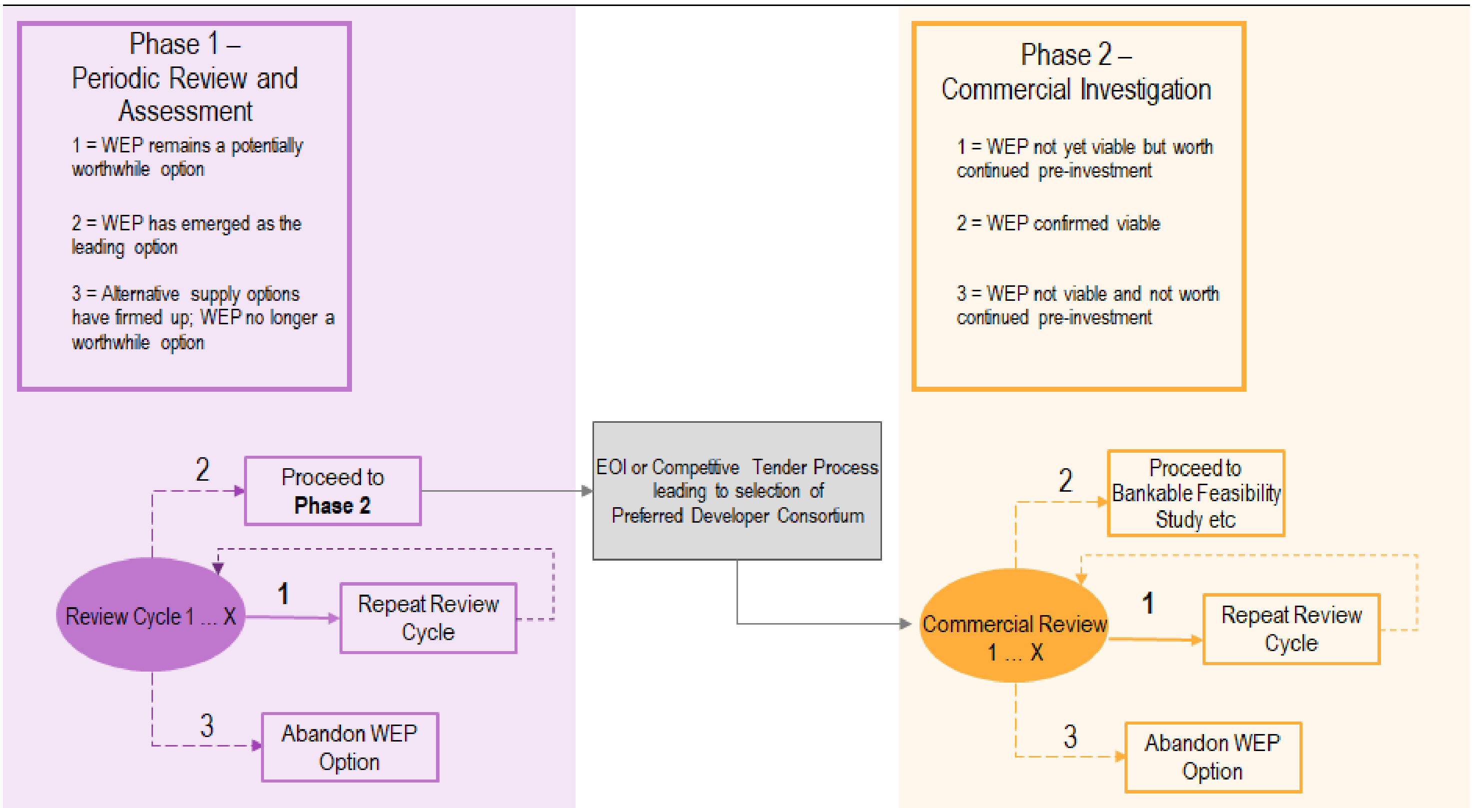
A 'real options' approach

A sensible real options approach to dealing with the longer-term issue of security of gas supply for the Eastern Australian market would involve maintaining a future option to proceed, or not to proceed, with the West-East Pipeline. In the interim, prudent, low-cost preparatory activities could be undertaken. Such activities would advance the project and help to reduce its delivery timeframe, while deferring any commitment to major capital expenditure unless and until it becomes clear that the West–East Pipeline has emerged as a commercially robust solution.

> **Recommendation 1:** Consideration should be given to a program of future activities aimed at advancing the West–East Pipeline concept and helping to reduce its delivery timeframe, while avoiding major pre-emptive capital cost commitments.

Consistent with a real options decision-making paradigm, a 'phased, gated approach' is proposed to progress the West–East Pipeline concept. This decision process is summarised in **Figure ES 3**.

FIGURE ES 3 PHASED, GATED DECISION PROCESS FOR PROGRESSING THE WEST–EAST PIPELINE



SOURCE: ACIL ALLEN CONSULTING

Phase 1 would involve a process of monitoring and periodic review of the West–East Pipeline's prospects as a commercially feasible and desirable option for bolstering east coast gas supply. These periodic reviews would best be undertaken by a government committee or working group involving representatives of Commonwealth and relevant State/Territory Governments They would include an assessment of progress on other east coast gas supply options. The conclusion of each review cycle would involve passing a 'decision gate' with three options: to repeat the review cycle; to proceed to Phase 2; or to abandon the West–East Pipeline option.

Phase 2 would involve commercial investigation by a mandated Developer, selected following an expression of interest or competitive tender process. The selected organisation or consortium would progress feasibility investigations on a commercial basis. It would periodically assess progress and report to the Government on the results of investigations, leading in each case to a 'decision gate' with three options: to continue to investigate the project; to proceed to a full Bankable Feasibility Study with a view to making a Final Investment Decision; or to abandon the project.

Recommendation 2: For Phase 1 of the gated decision process, establish a committee or working group involving representatives of Commonwealth and relevant State/Territory Governments to undertake periodic reviews of the West–East Pipeline's prospects as a commercially-feasible and valuable option for bolstering east coast gas supply, including assessments of progress on other east coast gas supply options.

The outcome of each Phase 1 review cycle should be an explicit decision to either:
1. Continue to monitor and repeat the review cycle; or
2. Proceed to Phase 2; or
3. Abandon the West–East Pipeline option.

Recommendation 3: If a Phase 1 review concludes that the West–East Pipeline has emerged as a valuable solution that is likely to be commercially viable, the Government should proceed to Phase 2 by running a process to select a commercial organisation or consortium (developer) to progress the project.

The selected developer should periodically report to the Government on the results of investigations, leading in each case leading to a decision to either continue investigations, to proceed to a full Bankable Feasibility Study and Final Investment Decision, or to abandon the project.

1 INTRODUCTION

The Australian Government through the Department of the Environment and Energy commissioned ACIL Allen Consulting Pty Ltd ("ACIL Allen") and GHD Pty Ltd ("GHD") to undertake a pre-feasibility study, including national interest and economic cost-benefit analysis, for the construction of gas pipeline infrastructure to deliver gas from Western Australia to the east coast gas market.

We refer to this project as the **West–East Pipeline**.

ACIL Allen was primarily responsible for those components of the pre-feasibility study relating to market assessment, gas demand and supply analysis, benefit–cost and economic impact analysis.

GHD carried out those part of the study related to pipeline engineering and cost estimation, route assessment and identification of route options, approvals and native title assessment, stakeholder mapping and engagement.

1.1 The pre-feasibility study

The pre-feasibility study provides an assessment of the potential for a West–East Pipeline to help address the problem of gas supply shortages in Eastern Australia by increasing gas supply in the east coast gas market. The Study Team has been asked to provide advice as to whether the construction of such a pipeline could solve part or all of this problem.

The study considers:

— whether there is likely to be sufficient gas supply to underwrite investment in new gas pipeline infrastructure, and the potential sources of gas supply in Western Australia that could underpin the construction and operation of a West–East Pipeline

— potential delivery points at which the West–East Pipeline could interface with existing pipeline infrastructure serving the east coast gas market

— pipeline route options to link source/s of supply with delivery point/s

— physical aspects of the pipeline, including relevant geological factors

— for each route option, the potential impacts that interconnection of the Western Australian and eastern states gas markets might have on the markets at either end of the pipeline, including effects on supply, demand, competition between suppliers, possible reduction in market share of current suppliers, gas prices, gas flows and potential implications for LNG producers

— the potential effects of the WA Government's current ban on hydraulic fracturing in the Perth metropolitan, Peel and South West regions, and the moratorium on hydraulic fracturing elsewhere in the state pending the outcomes of an independent scientific panel inquiry into the environmental effects of 'fracking'

— how the proposal could impact or be impacted by state and territory government environment approvals or policy

— potential impacts of possible Native Title claims or litigation of State or Federal environmental approvals (including on timing of the delivery of pipeline).

The study includes a cost-benefit and economic impact analysis for the most prospective pipeline route option, as established through the market and pipeline route analysis. We have also assessed the potential commercial return on investment in the pipeline and completed a high-level risk assessment.

The final part of the study report sets out our findings and recommendations. The findings from the study may inform the future development of a full feasibility study to test the viability of private enterprise developing the pipeline, with or without Commonwealth investment.

1.2 Report structure

This report is structured as follows:

— The **Key Findings and Recommendations** section summarises the results of the study and sets out recommendations based on those results.

— **Chapter 1** provides introductory material including a succinct statement of the project scope and a glossary of abbreviations and acronyms.

— **Chapter 2** sets out a diagnosis of the problem that the West–East Pipeline would be intended to address, namely a potential medium- to long-term shortfall in gas supply in Eastern Australia. It includes a summary discussion of options for addressing such a supply shortfall.

— **Chapter 3** describes the stakeholder consultation process undertaken as part of this pre-feasibility study and summarises the views of stakeholders on matters including market-related risks; identification of potential sources of supply; the role for governments and risks associated with government underwriting; regulatory risks; and routing considerations.

— **Chapter 4** sets out the market assessment of four main route alternatives, including the results of detailed modelling of market potential market penetration profiles under different pricing assumptions, and implications for gas production, consumption and delivered gas prices in Eastern Australia and Western Australia. Two other pipeline routes were tested, but not modelled in depth. Based on the modelling results, Pipeline Route 1 (Dampier – Moomba) is identified as the preferred route alignment.

— **Chapter 5** discusses the engineering route assessment and design considerations. It summarises consultation feedback on alternative route assumptions before setting out the results of a multi-criteria assessment route selection process used to determine optimal route alignments for the four main route alternatives. Also included in this chapter is an assessment of the Commonwealth, State and Territory approvals processes that would need to be complied with in order to construct and operate the project, and the implications of those approvals processes for project scheduling. Pipeline conceptual design considerations are set out together with the results of analysis of alternative pipe diameter/compression combinations.

— **Chapter 6** provides estimates of capital and operating costs for the preferred pipeline route (Route 1 – Dampier to Moomba) and associated compression facilities. It also discusses an indicative project timetable, identifying key tasks that would need to be completed to reach a final investment decision and construct the pipeline.

— **Chapter 7** sets out the results of a preliminary risk evaluation which identified and rated risks in relation to routing; design, construction & delivery; approvals; economics; and commercial and market issues. A risk register was complied, risk mitigation strategies identified, and assessments made of levels of post-mitigation residual risk.

— **Chapter 8** sets out the results of a formal cost-benefit analysis of the preferred pipeline route option.

— **Chapter 9** reports on the potential economic impacts of the project at State/Territory and National levels, based on Computable General Equilibrium (CGE) analysis of the West–East Pipeline development (under the preferred route option, Dampier to Moomba) compared to a reference case without the pipeline.

— **Chapter 10** discusses the way forward.

1.3 Glossary of Abbreviations and Acronyms

ABS	Australian Bureau of Statistics
ACCC	Australian Competition and Consumer Commission
ACT	Australian Capital Territory
ADGSM	Australian Domestic Gas Supply Mechanism
AEMO	Australian Energy Market Operator
AER	Australian Energy Regulator
AIE	Australian Industrial Energy
API	American Petroleum Institute
APLNG	Asia Pacific LNG Project, operated by ConocoPhillips and Origin Energy
APPEA	Australian Petroleum Production and Exploration Association
AS	Australian Standard
AUD	Australian dollar
Capex	Capital expenditure
CBA	Cost Benefit Analysis
CCGT	Combined Cycle Gas Turbine
CEMP	Construction Environmental Management Plan
CGE	Computable General Equilibrium modelling method for economic impact analysis
COAG	Council of Australian Governments
CPI	Consumer Price Index
CSG	Coal Seam Gas
CSIRO	Commonwealth Scientific and Industrial Research Organisation
DBNGP	Dampier to Bunbury Natural Gas Pipeline
DJTSI	Department of Jobs, Tourism, Science and Innovation (WA)
DMIRS	Department of Mines, Industry Regulation and Safety (WA)
domgas	Domestic gas (as distinct from gas for export as LNG)
EA	Eastern Australia
EA Act	Environmental Assessment Act (NT)
EIS	Environmental Impact Statement
EP Act	Environment Protection Act 1986 (WA); Energy Pipelines Act (NT)
EPBC Act	Environment, Protection and Biodiversity and Conservation Act 1999
ERD	Energy and Resources Division of the Department of Premier and Cabinet (SA)
ERF	Emission Reduction Fund
ESD	Environmental Scoping Document
FEED	Front-end engineering and design
FID	Final Investment Decision
FSRU	Floating Storage and Regasification Unit
FTE	Full-Time Equivalent (work)
GBJV	Gippsland Basin Joint Venture
GDP	Gross Domestic Product
GIS	Geographic Information System
GJ	Gigajoule, SI unit of energy
GLNG	Gladstone LNG Plant, operated by Santos Ltd
GMPIT	Gas Major Projects Implementation Team
GMRG	Gas Market Reform Group

GPG	Gas-fired Power Generation
GRP	Gross Regional Product
GSP	Gross State Product
InDeGO	Infrastructure Development Geospatial Options multi-criteria analysis tool
IRR	Internal Rate of Return
ISO	International Standards Organisation
JCC	Japan Customs Clearance (oil price standard)
kPag	Kilopascals gauge pressure
LA Act	Land Administration Act 1997 (WA)
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LRMC	Long Run Marginal Cost
MAOP	Maximum Allowable Operating Pressure
MAP	Moomba–Adelaide Pipeline
MCA	Multi-criteria analysis
MLV	Main Line Valve
mmbtu	million British thermal units, imperial unit of energy
MNES	Matters of National Environmental Significance
MSP	Moomba–Sydney Pipeline
MW	Megawatt, SI unit of power
MWh	Megawatt-hour, SI unit of energy
NEG	National Energy Guarantee
NEM	National Electricity Market
NGFR	National Gas Forecasting Report
NGP	Northern Gas Pipeline
NOI	Notice of Intent (NT)
NPV	Net Present Value
NSW	New South Wales
NT	Northern Territory
NT EPA	Northern Territory Environment Protection Authority
NWS	North West Shelf
OBPR	Office of Best Practice Regulation
OCGT	Open Cycle Gas Turbine
OEMP	Operational Environmental Management Plan
Opex	Operating expenditure
PEP	Pilbara Energy Pipeline
PER	Public Environmental Review
PGE Act	Petroleum and Geothermal Energy Act 2000 (SA)
PJ	Petajoule, SI unit of energy
PL	Pipeline Licence
PP Act	Petroleum Pipelines Act 1969 (WA)
PPI	Producer Price Index
PSL	Preliminary Survey Licence (SA)
PWC	Power Water Corporation, a Northern Territory Government-owned enterprise
QCLNG	Queensland Curtis LNG Project, operated by Shell
QLD	Queensland

RAMSAR	The 1971 Ramsar Convention on Wetlands of International Importance
RBA	Reserve Bank of Australia
RGNDI	Real gross national disposable income
SEA Gas	South East Australian Gas (pipeline)
SNP	Southern Northern Territory Pipeline
SRMC	Short Run Marginal Cost
TJ	Terajoule, SI unit of energy
USD	United States dollar
VTS	Victorian Transmission System
WA	Western Australia
WA EPA	Western Australian Environmental Protection Authority
WEP	West–East Pipeline

2 PROBLEM DIAGNOSIS

The idea of a trans-continental pipeline capable of shipping gas from Western Australia to Eastern Australia is not new. It dates back at least to the 1970s when former Whitlam-government Minister the Hon. Rex Connor proposed such a pipeline. Much more recently, with abundant resources of coal seam gas (CSG) having been proven up in Queensland prior to the emergence of the Gladstone export LNG projects, and with Western Australia facing a period of tight gas supply and rising prices, a similar concept but flowing gas in the opposite direction— from Moomba to Western Australia—was mooted.

The original west-to-east pipeline concept is once again being considered as a possible solution to the current problem of tight gas supply and sharply rising gas prices in Eastern Australia. Piping gas from Western Australia is one possible solution, but certainly not the only solution, to this problem. This study focusses on the case for a West–East Pipeline as a means of bolstering gas supply to the Eastern States. While some consideration has been given to other supply options, a detailed comparison of the West–East Pipeline with alternative means of increasing gas supply in Eastern Australia is outside the scope of this study.

As a general principle, it is reasonable to expect that a high-cost, long-distance infrastructure solution requiring a large, committed customer base and a long pay-back period will be a more commercially challenging option than smaller, more scalable responses that are nearer to the customer base and able to be delivered quickly when needed. On this basis alone, it is tempting to characterise the West–East Pipeline as a 'solution of last resort'—an option to be turned to only if other alternatives fail to materialise. Certainly, that is how many of the stakeholders consulted during this study viewed the project.

The first step in considering the merits of a West–East Pipeline as a solution to perceived problems of gas supply risk in Eastern Australia requires a systematic consideration of those problems and the various ways in which they could be addressed.

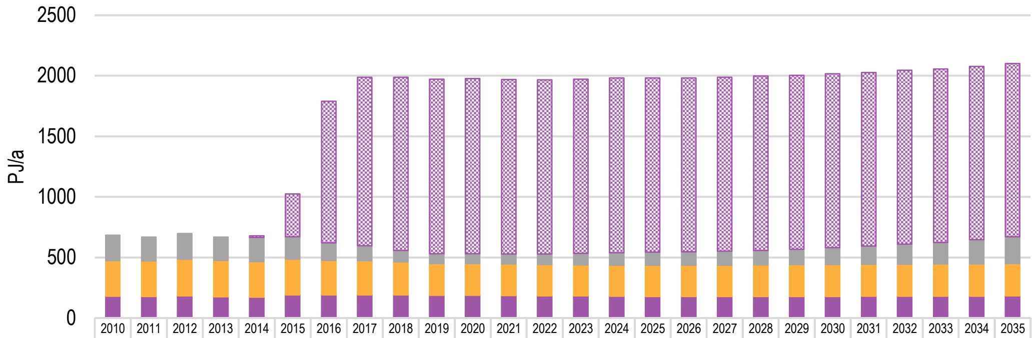
2.1 The current situation: gas supply and demand in Eastern Australia and Western Australia

2.1.1 Eastern Australia: prospects of tightening gas supply with little relief in sight

Over the past seven years there has been an unprecedented transformation of the Eastern Australian gas market, driven by large-scale export LNG developments and associated upstream coal seam gas (CSG) field production facilities in Queensland. Three separate LNG export projects, with a combined production capacity of more than 25 million tonnes per year of LNG, were commissioned between late 2014 and late 2016. These facilities have a combined gross gas requirement of around 1,500 PJ/a—more than double the amount of gas currently used in the entire eastern Australia domestic gas market.

The Australian Energy Market Operator (AEMO) in its 2016 National Gas Forecasting Report (NGFR; released December 2016) provided data on historical and forecast levels of gas demand in eastern Australia (Queensland, New South Wales, Victoria, Tasmania and South Australia; the NGFR does not include Northern Territory). **Figure 2.1** shows gas demand, by sector, under AEMO's Neutral scenario. It clearly illustrates the tripling of total gas demand in eastern Australia, driven by the rapid expansion of gas production to support the Gladstone LNG projects.

FIGURE 2.1 HISTORICAL AND FORECAST GAS DEMAND IN EASTERN AUSTRALIA



	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
LNG	0.0	0.0	0.0	0.0	13.3	353.8	1167.	1389.	1431.	1440.	1444.	1438.	1438.
GPG	212.3	198.0	210.5	194.8	201.5	185.5	146.6	124.9	94.0	84.1	82.1	82.7	88.0
Industrial	291.6	293.9	302.1	300.7	292.6	294.3	285.7	282.0	272.9	258.9	261.9	261.0	256.5
Res_Comm	180.7	177.6	184.2	174.2	171.5	191.7	189.6	190.5	189.9	189.3	187.9	186.0	184.0

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
LNG	1438.	1442.	1437.	1435.	1435.	1439.	1435.	1434.	1431.	1435.	1431.	1431.	1431.
GPG	95.9	102.5	108.8	110.8	113.8	118.9	127.5	139.4	151.5	165.3	178.5	199.4	221.0
Industrial	257.1	257.5	258.4	259.2	260.1	261.0	261.9	262.8	263.7	264.7	265.6	266.5	267.4
Res_Comm	181.8	179.9	178.4	177.1	177.2	177.8	178.3	178.8	179.3	179.9	180.4	181.0	181.7

SOURCE: ACIL ALLEN ANALYSIS OF DATA PRESENTED IN THE AEMO 2016 NATIONAL GAS FORECASTING REPORT, DECEMBER 2016

The impact that these LNG projects have had on the Eastern Australian domestic gas market would be difficult to overstate: they have affected the availability of gas to supply power generation, industrial, commercial and residential customers; they have pushed up the price of domestic gas and changed the ways in which gas prices are determined; and they have affected levels of domestic gas consumption, particularly in the power generation sector.

The LNG developments have seen the rapid expansion of gas production from CSG fields in Queensland. While the LNG export projects have been the primary driver for this increased production, some of this gas has been (and continues to be) supplied to the domestic gas market. Nevertheless, a large part of the gas production capacity in Eastern Australia has now been committed, on a long-term basis, to supply the LNG projects. This includes not only the Queensland CSG projects controlled by the LNG proponents, but also large volumes of third-party gas reserves that are now committed, under long-term contracts, to supply additional gas for LNG production. Some of the CSG fields developed to support LNG production have not performed as well as anticipated, with low gas flow rates and high production costs. This has created an opportunity for some third-party producers—traditionally suppliers to the domestic market—to secure long-term sales contracts to the LNG plants at relatively high prices.

Chief Scientist Dr Alan Finkel in the report of his independent review into the future security of the National Electricity Market noted that:

'Some LNG projects have experienced difficulties in extracting reserves and higher than expected costs of production. Restrictions on exploration and production have also been a significant factor. As a result, significant volumes of gas originally intended for the domestic market are being exported.'

Production levels in some of the conventional gas fields that have for many years been major sources of gas supply for local consumers are declining. As a result, many large-scale gas users in Eastern Australia have reported difficulties in securing new gas supply contracts. Where offers of supply have been forthcoming, they have often been at prices much higher than in the past.

In the longer term, there is significant uncertainty regarding gas supply adequacy in Eastern Australia. The Australian Competition and Consumer Commission (ACCC) in its 2016 inquiry into the east coast gas market saw three key factors as contributing to uncertainty about future gas supply:

— the magnitude of gas flows to the LNG projects, which are removing gas from the domestic market

- low oil prices, which have seen declining investment in gas exploration and lower production forecasts for both domestic producers and LNG projects
- moratoria and regulatory restrictions, which are affecting onshore gas exploration and development.

These factors continue to influence the supply-demand outlook. The ACCC's Interim Report on its Gas Inquiry 2017 – 2020, issued in September 2017, noted that the supply outlook in Eastern Australia had 'deteriorated significantly' as a result of lower forecasts levels of production, particularly in Bass Strait; significant volumes of LNG above contract levels being sold on international LNG spot markets; and increased levels of domestic demand largely due to increased use of gas for power generation.

The ACCC found that production from traditional sources of supply will continue to decline. It expects production from the Gippsland Basin Joint Venture (GBJV) to fall from a record level of 330 PJ in 2017 to 244 PJ in 2018 due to both natural decline in legacy gas fields and investment decisions made by the operators. While this level of production is broadly in line with GBJV's historical rates of production over the period 2011–15, it will leave a significant gap in supply to domestic users in the southern States because of declining output from other conventional fields—notably in the Cooper Basin in Central Australia and the Otway Basin in Bass Strait.

In its latest *Gas Statement of Opportunities Update* (September 2017) AEMO concluded that 'the aggregate gas supply available to the domestic market in eastern and south-eastern Australia may not be sufficient to meet the total annual energy requirements of domestic gas users in these regions in 2018 and 2019.'

AEMO found that there is potential for an annual energy shortfall in the domestic gas market in eastern and south-eastern Australia, of 54 PJ in 2018 and 48 PJ in 2019. It also concluded that the shortfall could be even higher under a variety of plausible circumstances that could increase demand for gas by household and business consumers, and for gas-powered generation of electricity. AEMO estimated that, considering these uncertainties, the shortfall could be as high as 107 PJ in 2018 and 102 PJ in 2019.

Subsequently, in December 2017, the ACCC issued a further interim report in which it concluded that the supply-demand outlook for the east coast gas market had improved, with a lower likelihood of a supply shortfall. While the supply-demand balance was found to remain tight, under AEMO's expected domestic demand forecast there no longer appeared to be a shortfall during 2018 or 2019, and under AEMO's upper band forecast, the estimated shortfall had reduced from 108 PJ to 33 PJ in 2018, and from 201 PJ to 24 PJ in 2019.

The ACCC attributed the improved outlooks for 2018 and 2019 to 'slight increases in forecast production by some of the key producers in the east coast, but more significantly, reduced export forecasts by the LNG projects in Queensland.' The report noted that since the September 2017 report, the LNG projects had diverted significant quantities of gas originally intended for export to the domestic market.

The ACCC December 2017 report reiterated the earlier finding that gas production in the southern states would be insufficient to meet forecast demand in the southern states from 2018 due to natural decline of major known gas resources and a lack of new supplies. As a result, the ACCC found that southern users would need to rely on Queensland gas.

The current tight supply situation has been exacerbated by restrictive government policies in New South Wales, Victoria and the Northern Territory that have brought onshore oil and gas exploration in those jurisdictions to a virtual standstill.

2.1.2 Western Australia: challenges in the longer term

While Eastern Australia is facing a situation of declining production from traditional supply sources; weaker than expected performance from some CSG fields; and policy constraints on new gas developments, the gas supply situation in Western Australia is not without its challenges.

AEMO in its latest Western Australian Gas Statement of Opportunities report (published December 2017) concluded that in the near term (to 2020) the domestic gas market in Western Australia will be well-supplied, with potential gas supply likely to exceed forecast demand over the entire ten-year outlook period **provided** that new reserves are developed.

However, the market operator pointed to some uncertainty in the medium term, when reserves for domestic-only gas producers are expected to fall and prices may remain relatively low. In these circumstances, the new gas reserves needed as current reserves are depleted may not be developed, and supply may not meet demand in the medium to long term. AEMO also warned that the risk of insufficient new supply was exacerbated by low levels of exploration which, in 2017, stood at the lowest level since 1990—a concerning trend given the long development lead times for new petroleum fields. The current moratorium on hydraulic fracturing is likely to further dampen exploration for some time.

AEMO pointed to continued slow growth in Western Australia domestic gas demand, which it saw as being dependent on new resources and industrial gas-consuming projects, noting that a 'mixed outlook persists for WA commodities'.

AEMO also noted the following recent developments in the Western Australian gas market:

— commissioning of two new domestic gas production facilities—Gorgon and Xyris—adding 31 per cent to production capacity and bringing the total to 1,659 TJ/d
— a total pipeline capacity increase of 58 TJ/day, reflecting new capacity from the Fortescue River Gas Pipeline and expansions to the Goldfields Gas Pipeline
— a quadrupling of storage capacity to 60 PJ with the commissioning of the new Tubridgi storage facility
— three new entrants to the retail gas market
— two new LNG export plants—Gorgon and Wheatstone—contributing to a doubling of liquefaction export capacity.

These positive developments suggest that the Western Australian gas industry is generally in good health. However, there are some medium-term risks to supply:

— At the end of 2020, large legacy contracts for gas supply from the North West Shelf expire. Total supply levels and the extent of the domestic market obligation of the North West Shelf are expected to reduce.
— From 2022, there is further uncertainty for potential supply as a result of several domestic gas production facilities facing reserve depletion.

AEMO's 'Low potential supply scenario' sees a shortfall of up to 155 TJ/d by 2021. AEMO considers that this scenario is unlikely to emerge because it expects that price signals will encourage new supply. However, it warned that:

'If exploration continues to be minimal, new gas reserves may not be developed, and some existing gas production facilities may cease production in the medium term, due to lack of gas feedstock.'

AEMO went on to note that despite the large endowment of potential gas resources in WA, the current level of well-defined proved and probable (2P) reserves 'will not meet gas demand for the outlook period, and further exploration and development will be required for Base potential supply to meet demand'.

Implications for the West–East Pipeline proposal

The current supply-demand situation in Western Australia has significant implications for the West-East Pipeline. There is no large excess of domestic gas production capacity in Western Australia seeking a market outlet. Moreover, AEMO has identified that there will need to be a significant level of investment in exploration and development in the medium term just to maintain domestic production at the levels required to meet the State's forecast demand. This means that, in effect, all the gas supply required to meet a long-term delivery target of 500 to 600 TJ/d into a West–East Pipeline will need to come from new production capacity developed specifically for the purpose, either as a brownfield expansion of an existing facility or as a new greenfield development. It will not come from existing domestic gas production facilities in Western Australia.

This is a key insight because it means that the proponent of a West–East Pipeline will need not only to secure commitments from gas shippers to pay for pipeline services, and therefore from gas buyers willing to lock into long-term (20-year) gas supply via the pipeline, but will also need to find a gas producer willing to commit the necessary gas reserves to the enterprise (at least 3,500 PJ over 20 years) and to invest in the construction and operation of the new production facilities required to deliver that gas into the pipeline.

Aligning producer and customer interests is likely to prove very challenging due to the 'Catch-22' situation: a producer is unlikely to make the required commitment of reserves, or to invest in new production facilities, without having customers locked in. Customers are unlikely to make binding commitments to the pipeline or to contract for gas supply unless they have confidence that both the production facilities and the pipeline will be built. The issue would be more easily solved if there was a stranded gas resource, of appropriate size and suitably located, actively looking for a market outlet.

2.2 Current and prospective sources of gas supply

2.2.1 Current gas supply in Eastern Australia

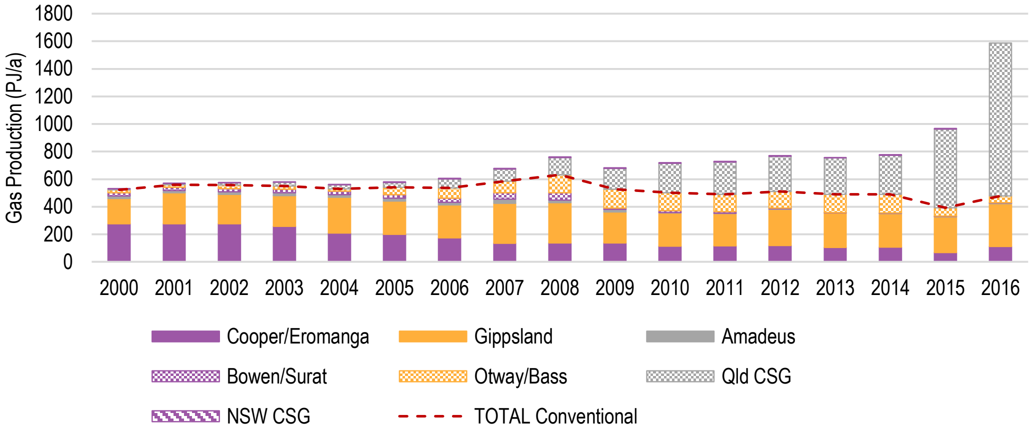
For many years the Eastern Australian gas market relied on conventional gas sources, originally developed as a by-product of oil production in four producing regions:

1. The **Gippsland, Otway and Bass Basins** in the **Bass Strait** region, providing the principal source of gas supply for Victoria and, more recently a substantial portion of gas supply for South Australia and New South Wales/ACT.
2. The **Cooper Basin in South Australia**, which was initially the primary source of gas supply for South Australia and New South Wales. Over the past 15 years the Cooper Basin's contribution to supply in these states has declined with pipeline connections from the Bass Strait region (Eastern Gas Pipeline and Victoria – NSW Interconnect to New South Wales; SEA Gas pipeline to South Australia) meeting an increasing share of the market in those states. However, the Cooper Basin remains a significant source of supply to the domestic market as well as now supplying gas to the GLNG plant at Gladstone.
3. The **Surat & Bowen Basins** in southern Queensland, which was the initial source of supply of natural gas to consumers in southeast Queensland following commissioning of the Roma–Brisbane Pipeline in 1969. Only minor amounts of conventional gas are now produced in the Surat and Bowen Basins. However, these areas have become the focus of large-scale CSG production supplying both export LNG operations and domestic customers.
4. The **Cooper Basin** in South West Queensland (Ballera Gas Plant) which commenced production in 1994 supplying gas to southeast Queensland (replacing declining production from the Surat and Bowen Basin conventional fields), Mount Isa and to South Australia and New South Wales (via Moomba). According to the AEMO Natural Gas Services Bulletin Board, the Ballera Gas Plant has not produced sales gas since July 2015. All raw gas gathered and processed at Ballera is now transferred to Moomba for final processing and delivery into the transmission pipeline system.

Over the past decade, CSG production in Queensland (from the Surat and Bowen Basins) has increased rapidly, initially serving domestic customers in Queensland, South Australia and New South Wales and more recently (since late 2014) supplying most of the gas feed to the three Gladstone export LNG plants.

The historical profile of Eastern Australian gas production since 2000, by source, is summarised in **Figure 2.2**.

FIGURE 2.2 EASTERN AUSTRALIA GAS PRODUCTION, BY SOURCE



SOURCE: ACIL ALLEN COMPILATION OF APPEA PRODUCTION DATA (TO 2014); AEMO NATURAL GAS SERVICES BULLETIN BOARD DATA (FROM 2015)

The main sources of gas supply for the south-eastern Australian market are the Gippsland, Otway and Bass Basins located principally offshore in Bass Strait. These supply sources have become increasingly important to the Eastern Australian domestic market as much of the production in Central Australia (Cooper Basin) is being directed to LNG export markets through Gladstone, rather than to domestic markets.

Table 2.1 summarises the remaining gas reserves and resources in Eastern Australia as at 31 December 2015, according to data prepared by Core Energy for AEMO and published as input data to the 2017 AEMO *Gas Statement of Opportunities*. It is revealing to note that, of the total 39,166 PJ of yet-to-be-developed Proven and Probable (2P) Reserves in Eastern Australia, 98 per cent is Queensland CSG and 89 per cent is directly controlled by the Queensland LNG projects.

TABLE 2.1 EASTERN AUSTRALIA GAS RESOURCES

Basin	Project	2P Developed	2P Un-developed	2C	Prospective Resources
Bass	BassGas	99	0	99	0
Clarence Moreton	Clarence Moreton	0	0	575	13,875
Cooper	Cooper Eromanga Basin	661	605	7,496	80,974
Gippsland	GBJV & Turrum & Kipper	3,056	0	686	4,062
Gippsland	Gippsland - Non GBJV	0	0	0	1,802
Gippsland	Longtom & Sole	106	0	313	260
Gunnedah	Gunnedah	0	0	971	3,502
Otway	Casino, Henry and Netherby	153	0	30	0
Otway	Halladale/Black Watch/Speculant	79	0	0	0
Otway	La Bella	0	0	0	1,107
Otway	Minerva	17	0	0	0
Otway	Otway Gas Project	236	0	0	0
Otway	Unconventional Otway	0	0	0	11
Surat & Bowen	Moranbah CSG	735	2,550	5,548	0

Basin	Project	2P Developed	2P Un-developed	2C	Prospective Resources
Surat & Bowen	QLD CSG - ORG / APLNG	1,059	9,483	3,030	0
Surat & Bowen	QLD CSG - Arrow Energy (excl. Moranbah)	497	9,327	17,923	10,807
Surat & Bowen	QLD CSG - GLNG	990	5,588	1,328	0
Surat & Bowen	QLD CSG - Other	132	1,259	4,611	26,881
Surat & Bowen	QLD CSG - BG / QCLNG	2,225	10,354	13,700	8,586
Surat & Bowen	Surat-Bowen-Denison	66	0	120	0
Sydney	Camden	40	0	0	0
Total		**10,151**	**39,166**	**56,429**	**151,867**

Note: Reserves and resources as at 31 December 2015

SOURCE: CORE ENERGY 2017, CONTRACTS, RESERVES AND COST ASSUMPTIONS DATA FILE PREPARED FOR AEMO GSOO 2017

Gippsland Basin

The Gippsland Basin contains the largest conventional gas reserves in Australia outside the Carnarvon Basin of Western Australia and the Bonaparte Basin/Timor Sea. All current production from the Gippsland Basin is controlled by the Esso/BHP joint venture. In the past, Esso/BHP jointly marketed their Gippsland Basin gas entitlements; that arrangement is now coming to an end, with the joint venture parties having committed to separate marketing of their gas entitlements from 1 January 2019.

First production through the Longford Gas Plant commenced in 1969. As well as being the major source of gas supply for the Victorian market, the Gippsland Basin now supplies well over half of the gas consumed in New South Wales and most of the Tasmanian market.

The capacity of the processing plant at Longford has recently increased from 1,030 TJ/day to 1,115 TJ/d following the start-up of gas production from the Kipper–Turrum project. During the winter months it has tended to operate up to a plateau at the full current design capacity of 1,030 TJ/d. Commissioning of Kipper and Turrum fields could potentially result in up to 300 TJ/d of increased production capacity, but this will be offset by declining deliverability in established fields over the next few years.

Given the size of the remaining uncommitted reserves, there is potential for significantly increased production. However, a large portion of the remaining undeveloped reserves lie in relatively deep and remote fields. New field development is likely to be more expensive and will only be undertaken if warranted by market prices.

Otway Basin

Onshore gas production from the Victorian portion of the Otway Basin commenced in April 1986, when the North Paaratte Field was commissioned. The Iona Gas Field within the Port Campbell Embayment commenced production in July 1992. Over the next fifteen years several other small onshore fields in the Otway Basin were developed, supplying modest quantities of gas to the Victorian market.

The first offshore development in the Otway Basin, the Minerva field was discovered in 1993 and brought into production during 2005. Subsequent offshore developments included the Casino project (including Henry, Martha and Netherby fields) in early 2006 and the Otway Gas Project (Thylacine and Geographe fields) which commenced gas delivery in November 2007.

The offshore Otway Basin fields have seen aggregate deliverability decline significantly over the past five years. The recent tie-in of the Halladale and Speculant fields to the Otway Gas Project has bolstered regional peak deliverability in the short term, but in the mid-term new developments will be needed if production levels are to be maintained.

The prospect of further gas discoveries in the onshore Otway Basin is currently hampered by a Victorian Government decision to extend a ban on all onshore oil and gas exploration and development in the State until at least mid-2020. As a result, there is now no prospect of any new gas supply from the onshore regions of Victoria (including the onshore Otway and Gippsland Basins) for at least the next five years.

Bass Basin

The Bass Basin lies wholly offshore in Tasmanian waters between the Gippsland and Otway Basins. The main fields in the Bass Basin include Yolla, White Ibis, Trefoil and Rockhopper/Gentoo.

The only production in the Bass Basin comes from the BassGas Project centred on the Yolla gas field. A multi-phase pipeline carries gas, condensate and LPG to a processing plant on the Victorian coast near Lang Lang, 100 km southeast of Melbourne. The project came into production, at a design rate of 65TJ/d, in mid-2006.

2.2.2 Future gas supply in Eastern Australia

Analysis undertaken by the ACCC in its review of the Eastern Australian gas market in 2016 concluded that in the medium term (to around 2024) sufficient gas will be produced in the east coast gas market to meet domestic demand as well as the current export contract commitments of the three Gladstone LNG plants. This position was, however, reliant on a large quantity of currently undeveloped supply sources for both the LNG projects and other producers (up to 1,000 PJ/a by 2025) being brought into production. Furthermore, the analysis also showed that there would be insufficient gas produced in the east coast market—including all proposed but currently undeveloped supply for the LNG projects and other producers—to meet domestic demand *and to allow the LNG projects to fully utilise their installed liquefaction plant capacity*. The ACCC noted that this gap between current levels of LNG supply contracts and the full capacity of the LNG plants was influencing decisions made by gas producers on the east coast and was resulting in domestic gas prices being influenced by LNG netback prices.

While in the long run it is reasonable to expect that gas producers will respond to price signals in the market, new greenfield sources of gas supply will not be developed quickly. The process of exploring for and finding new gas fields, establishing their technical and commercial viability and bringing them into production involves long lead times. This situation has been exacerbated by the emergence of a range of restrictive government policies which are constraining onshore exploration and production activities (notably in Victoria, New South Wales and the Northern Territory) and by increasingly complex approval processes that are leading to increased lead times between discovery and commercial production.

In considering where future gas supply will come from to support the east coast domestic gas market, it is important to recognise that 90 per cent of the current Proven and Probable (2P) gas reserves in Eastern Australia, both developed and undeveloped, are contained in CSG fields in Queensland.[3]

Potential new sources of **conventional** gas supply in Eastern Australia include:

- **Offshore Gippsland Basin:** conventional prospects such as Manta, South East Remora, South East Longtom and Dory could provide additional production However, some of these projects are relatively remote, being further offshore and in relatively deep water when compared with current producing fields and are likely therefore to produce relatively high-cost gas. Some also have high CO_2 contents which will increase processing costs.
- **Offshore Otway Basin:** Ongoing exploration activity in the Otway Basin supports the view that further significant gas discoveries are likely to be made in this region. The strong upward pressure on gas

[3] The ACCC east coast gas market inquiry report cites EnergyQuest *EnergyQuarterly*, March 2016, table 17, stating that approximately 90% of 2P gas reserves in the Eastern Australian market as at February 2016 were estimated to be made up of CSG. This is confirmed by the Core Energy data presented in this report at **Table 2.1**.

prices that is now evident throughout eastern Australia should provide commercial incentives for continued exploration and development in the Otway Basin. Possible development prospects include the La Bella field (discovered 1993) and the Flanagan prospect, located east-southeast of the Thylacine field.

— **Offshore Bass Basin:** possible future developments include a gas-condensate discovery in the Rockhopper exploration well, and the Trefoil gas field.

— **Onshore Gippsland and Otway Basins:** Prospects are heavily impacted by the current Victorian Government moratorium on onshore petroleum exploration. There has been some recent encouragement in the South Australian sector of the Otway Basin with the Haselgrove gas discovery in January 2018.

— **Cooper Basin SA/Queensland:** Ongoing exploration targeting conventional production in the Cooper Basin may yield modest replacement and incremental production. Remaining conventional targets are typically small. Some of this gas is likely to be directed to the GLNG project through the Santos' 'Horizon' Contract, but some will be directed to domestic sales.

— **Surat/Bowen and Clarence–Moreton Basins Queensland/NSW:** Conventional production in the Surat and Bowen Basins has declined to very low levels (less than 10 PJ/a) and it not expected to recover. Most exploration effort in the region is now targeted to unconventional targets (CSG). The Clarence–Moreton Basin, which is of similar age and geology to the Surat Basin, extends from southern Queensland into northern coastal New South Wales. The New South Wales portion is prospective for both conventional and unconventional gas. However strong public opposition and lack of government support for exploration activities in the region mean that all exploration has halted and there appears to be very little prospect of further gas exploration in the area in the foreseeable future.

Potential new sources of **unconventional** gas supply (CSG, shale gas, basin-centred gas) in Eastern Australia include:

— **Queensland CSG:** Production of CSG in the Surat and Bowen Basins of Queensland has expanded rapidly, providing the primary sources of supply for the Gladstone export LNG plants and now accounting for almost two-thirds of eastern Australian gas production. Queensland CSG has also been a major supplier to the domestic market over the past decade and will continue to be an important domestic supply source. However, most of the Queensland CSG reserves and contingent resources are controlled by companies involved in the Gladstone LNG projects, and supply is for the most part being directed into the LNG plants. The key uncertainties in relation to future supply of Queensland CSG into the domestic market therefore relate to the willingness and capacity of the LNG project operators to direct supply away from LNG into the domestic market in response to market signals. Risks to Queensland CSG supply for domestic markets include some areas of poor production performance and high production costs, and low oil prices which have tended to reduce the amount of economically recoverable reserves and to constrain upstream capital expenditure.

— **NSW CSG:** exploration for and development of CSG resources in New South Wales has largely stalled in the face of public opposition and restrictive government policies. Only one project (Santos Narrabri) remains on foot. That project is making some headway, having recently submitted its Environmental Impact Statement and is now progressing the environmental approvals process. If the Narrabri project does eventually proceed it has the potential to ramp up, through a series of stages, to a production capacity of up to 200 TJ/d (in accordance with the Narrabri EIS).

— **Cooper Basin shale/tight gas:** estimates of unconventional gas-in-place in the Cooper Basin are very large. The Moomba–191 shale gas well was brought into production in 2012 and was the first shale gas well in Australia to produce gas commercially. However, after an active period of exploration and testing prior to the mid-2014 collapse in oil prices, work on unconventional targets in the Cooper Basin has largely stalled. There has been some technical success, but there are no declared proven or probable reserves of unconventional gas in the Cooper Basin. The major slow-down in exploration since mid-2014 brings into focus the question of whether much of the resource base will be economic to produce at lower oil prices. Further work is required to assess technical and commercial aspects of Cooper Basin unconventional gas production, and so to determine the potential contribution of these gas sources to the gas supply mix in eastern Australia.

— **Northern Territory supply:** Gas production in the Northern Territory is becoming relevant to the Eastern Australian supply–demand situation with the Northern Gas Pipeline, currently under construction, due to be completed in late 2018. Current domestic gas supply sources in the NT gas market are:

- Offshore – Blacktip field in the Bonaparte Basin. Blacktip gas will provide the initial supply into Queensland via the Northern Gas Pipeline.
- Onshore – the Mereenie, Palm Valley and Dingo fields in the Amadeus Basin.

The Bayu-Undan field in the Bonaparte Basin has been supplying gas into the Darwin LNG project since 2006. It is not expected to supply any gas into the domestic market, with all reserves and production currently committed to LNG exports.

Gas and condensate from the Ichthys field, located in Western Australian waters in the Browse Basin some 890 km west of Darwin, will be transported to the Inpex LNG plant at Darwin which is now nearing completion. There is currently no expectation that the Ichthys project will provide any gas to the domestic market in the Northern Territory or Eastern Australia.

The Beetaloo Sub-basin (part of the Macarthur River Basin) in the Northern Territory is regarded as highly prospective for shale gas. Several exploration companies were actively working on Beetaloo Basin prospects prior to September 2016 when the Northern Territory Government announced a moratorium and independent scientific inquiry into hydraulic fracture stimulation in the Northern Territory. As a result, exploration for unconventional gas reserves in the Beetaloo Basin is currently at a standstill. The final report of the inquiry is now scheduled to be released during the first half of 2018. Depending on the outcomes of that inquiry, and the Northern Territory Government's responses to its recommendations, there may be a resumption of exploration activity in the Beetaloo Basin. The timing and scale of any commercial gas production from the Beetaloo Basin, and the level of supply into the Eastern Australian states, remains uncertain.

2.2.3 Current gas supply in Western Australia

The current sources of domestic gas supply in Western Australia and their rated capacities are:

- Karratha Gas Plant (North West Shelf Project) – 630 TJ/d
- Varanus Island Gas Plant – 360 TJ/d
- Devil Creek Gas Plant (Reindeer–Caribou fields) – 220 TJ/d
- Macedon Gas Plant – 220 TJ/d
- Gorgon Domestic Gas Plant (Phase 1) – 182 TJ/d
- Beharra Springs Gas Plant – 19.6 TJ/d
- Xyris Gas Plant – 10 TJ/d
- Red Gully Gas Plant – 10 TJ/d
- Dongara Gas Plant – 7 TJ/d

The nine gas production facilities have a total nameplate capacity of about 1,659 TJ/day. According to the AEMO *2017 Gas Statement of Opportunities for Western Australia*, the combined peak daily production rate of these plants during 2016–17 was 1,465 TJ/d, with an average production rate of about 1,034 TJ/d.

The peak daily rates of production achieved by the Devil Creek and Varanus Island gas plants during 2016–17 were well below nameplate capacity at 67% and 76% respectively. This suggests that deliverability from these sources has declined from peak production levels.

Recent production statistics also show that average gas production from the Karratha Gas Plant and Dongara fell over the course of 2016–17. In the case of the Karratha Gas Plant (North West Shelf), average daily production declined from 496 TJ/d during the third quarter of 2016 to 362 TJ/d in the second quarter of 2017. AEMO attributes this reduction to expiry of existing contracts, with new gas contracts signed with other domestic gas production facilities. It highlights the fact that the North West Shelf project—up until now the cornerstone of domestic gas supply in Western Australia—will in future have a diminishing role in domestic gas supply.

Data compiled and presented by AEMO indicates that Western Australia had conventional proven and probable (2P) gas reserves of about 73,900 PJ as at September 2017. Estimates of unconventional shale gas resources ranged from a low of 96,500 PJ to a high of more than 200,000 PJ. A further 91,200 PJ were estimated to be contained in unconventional tight gas resources.[4]

Western Australia accounts for almost all (around 92 per cent) of Australia's remaining conventional gas resources, with production and ongoing exploration activities in the Bonaparte, Browse, Canning, Carnarvon and Perth Basins.

More than 95 per cent of the conventional gas reserves in Western Australia are held by LNG export companies and joint ventures. LNG projects have an obligation under the WA Domestic Gas Policy to set aside reserves equivalent to 15 per cent of LNG production for domestic market use. Commercial terms of domestic gas supply, including price and timing, are not regulated but are subject to commercial negotiation.

2.2.4 Future gas supply in Western Australia

The **Wheatstone** domestic gas plant is expected to come on line by the end of 2018, adding a further 200 TJ/d of production capacity to the WA domestic market.

Gorgon Phase 2 is expected to commence operations in 2020, increasing Gorgon domestic gas production capacity by 118 TJ/d to a total of 300 TJ/d.

The **Dongara** Plant is expected to be decommissioned as the associated gas fields are nearing depletion and no longer producing[5].

There are large reserves of gas yet to be developed in Western Australia, particularly in the offshore Browse and Carnarvon Basins. However, as indicated above, most of these reserves are held by LNG export companies and joint ventures. Their future development is likely to be tied to LNG production (either new facilities or as 'backfill' into existing plants). This is not only because of the ownership and control of those resources but also because the very large capital costs involved in bringing these fields into production are require the economies of scale that only large export-oriented production facilities can provide.

A prolonged and steep decline in exploration drilling activity in Western Australia places a question mark over the longer-term development of replacement reserves. Data published by AEMO shows that the number of exploration wells drilled in Western Australia fell steadily from more than 190 in 2008 to less than 10 in 2017.[6]

2.3 Gas prices

2.3.1 Gas prices in Eastern Australia

Historically most of the gas in Australia was bought and sold on the basis of long-term bilateral contracts, typically for terms of 10 to 20 years. Transportation contracts were structured to match these long-term sales contracts and had similar durations. More recently there has been a trend toward shorter term supply, with many recent gas sales contracts written for periods of less than five years. Foundation contracts underpinning major new facilities (production projects, major transmission pipelines and large gas-consuming plant) are still often settled for terms of up to 20 years. Indeed, it is commonly argued that, to finance new gas-based projects in Australia, long-term contracts are essential to both buyers and sellers, providing security of supply as well as cost and revenue stability.

Periodic price review mechanisms, which provide some protection to both buyers and sellers against prices moving and remaining seriously "out of market", are a feature of most long-term gas supply contracts. Between reviews, prices are typically defined according to a base price indexed periodically (most often to CPI). Contract prices therefore do not tend to fluctuate on a daily or seasonal basis. However, the many variations in detailed commercial provisions such as term, volume, volume flexibility (minimum bill or 'take-or-pay' levels; banking rights; relationships between annual contract quantities and maximum daily quantities), penalties associated with failure to supply, and so forth mean that there can be very significant price differences between contracts. The idea of a single

[4] AEMO 2017, Gas Statement of Opportunities for Western Australia, Table 5.
[5] AEMO 2017, Gas Statement of Opportunities for Western Australia, p. 17.
[6] AEMO 2017, Gas Statement of Opportunities for Western Australia, Fig.9, p. 24.

market clearing price therefore has limited relevance to long-term contract supply in the Eastern Australian market.

Gas prices in Australia were for many years low by international standards and the prevalence of long term contracts ensured price stability. Particularly in Eastern Australia, natural gas was seen as a substitute for coal and coal-based electricity, rather than for oil or other petroleum products. Australia's abundant, low-cost coal resources effectively capped gas prices, limiting the prices that large-scale users in power generation and industrial applications were willing and able to pay. In this regard, the Australian market was quite different from the markets in many overseas countries, including the USA, UK, Europe and a number of Asian countries where gas prices tend to follow oil prices.

The role of costs in setting gas prices

Costs of production influence but do not determine the price of gas in the Australian market. In the past, local gas prices were set by reference to the price of alternative energy sources (particularly coal) rather than by costs of production. Gas has not historically been priced on a 'cost-plus' basis that provides an economically efficient return over costs of production. It has been priced based on 'what the market will bear' taking into consideration competitive alternatives. Cost of production will, however, set a lower bound on future gas prices in the sense that producers will not invest in new production capacity if the market sustainable price fails to cover the long run cost of establishing and operating that capacity, including a risk-reflective commercial rate of return. This is likely to be a particularly significant consideration in the development of large offshore gas fields that face high development costs, and unconventional gas resources that require intensive technical intervention to establish and maintain commercial rates of production.

Gas pricing trend in Eastern Australia

Through the early 2000s, wholesale domestic gas prices throughout Eastern Australia remained low. In southern Australia prices generally moved in line with inflation; in Queensland where the CSG industry was emerging and new producers were keen to establish market share, new supply contracts saw significant discounting.

During 2007 and 2008, the outlook for prices changed significantly because of a number of converging factors:

— There was sustained upward pressure on exploration and development costs. This trend was not confined to Australia but was observed around the world. It was particularly evident in offshore oil and gas developments where upstream development cost indicators more than doubled between 2005 and mid-2008.
— High oil prices—which in July 2008 climbed above US$140 per barrel—flowed on to international gas prices, including to Australian LNG exports. This accentuated the gap between international prices and Australian domestic prices.
— Proponents of LNG plants in Queensland began to focus attention on establishing reserves and production capability to underpin their proposed developments. As a result, while these producers were willing to sell gas on a spot or short-term basis, they became less willing during the reserves-build process to enter into long-term, large volume supply contracts.
— Drought conditions in eastern Australia during 2007 saw electricity prices rise sharply as some coal-fired plant in Queensland and New South Wales was unable to run because of lack of water—and gas prices followed. While both electricity and spot gas prices retreated with the easing of drought conditions and relaxation of other generation constraints, the demonstrated ability of the market to absorb higher gas prices continued to influence near-term price settlements.

From mid-2008 there was a significant softening of prices in the Victorian spot market, driven by the introduction of new supply from the Otway and BassGas Projects. More generally, the after-effects of the Global Financial Crisis and falling oil prices tempered the upward pressure on gas prices.

In the years leading up to the commissioning of the LNG plants in Central Queensland two opposing effects became apparent. The availability of gas for sale under long-term contracts became (and remains) highly constrained with LNG proponents purchasing large quantities of third-party gas to bolster their own equity CSG supplies. Gas buyers seeking to roll-over existing long-term contracts or to enter into new long-term contracts found difficulty in securing offers of supply, with producers seeking much higher prices. The main driver for these upward price trends appears to have been a growing expectation that the Gladstone LNG plants would need additional third-party gas and that this would drive prices in the medium term toward oil-indexed LNG netback prices.

Spot prices in the Victorian market and in the Sydney, Adelaide and Brisbane short term trading markets rose for a period (apparently in response to increasing supply tightness in the market) but then fell sharply during 2014, reaching very low levels as the ramp-up of CSG supplies in advance of LNG commissioning led to a temporary supply excess. Once commissioning of the LNG facilities commenced, however, spot prices recovered strongly. During the winter of 2016 spot prices in South Australia and Victoria rose to levels well beyond LNG netback[7], exceeding $20/GJ on numerous occasions. Clearly these prices were being set not by reference to the alternative use for LNG production, or even the cost of diverting gas from LNG production, but based on the marginal value to consumers forced to bid up the price to their maximum short-run capacity to pay or else risk losing supply.

The impact of LNG exports on domestic gas pricing

The emergence of the Gladstone LNG projects has had a transformative effect on gas prices in the Eastern Australian domestic market. In particular, there has been a significant shift in the basis on which gas sold under long-term supply contracts is priced. In the past, the usual practice in the gas industry was to set a base contract price at a specified date. That base price was then subject to escalation on a periodic basis at a proportion (most often 100 per cent) of the Consumer Price Index or anther relevant independent price index. Typically, the base contract price was also subject to periodic review.

With the advent of LNG export projects offering a pathway to an international market in which contract prices have traditionally been linked formulaically to the price of oil, it has now become commonplace for domestic gas supply contracts to incorporate oil price linkages.

The ACCC its 2016 East Coast Gas Market Inquiry made the following observation:

'Industrial gas users are now exposed to higher and more volatile domestic prices, which are influenced by fluctuating international LNG and world oil prices. This is likely to remain a feature of the east coast gas market into the future. Recent low oil prices have provided some price relief but have also stifled investment required to bring on additional gas, which perpetuates uncertainties about availability of gas. Industrial users are adapting their practices for acquiring gas in response to increased pricing and supply uncertainties, but limited publicly available information and risk management mechanisms are making this challenging'.[8]

Current contract prices

In January 2018 Oakley Greenwood published a report titled *'Gas Price Trends Review 2017'* which was prepared for the COAG Energy Council (published on the Department of Environment and Energy website). This was an update of an earlier report prepared by Oakley Greenwood in 2015. The report contains an aggregation of historical gas prices for each State/Territory jurisdiction in Australia.

The report identifies the prices at which new gas contracts were settled in each year since 2006, rather than the average price of gas sold under term contracts in each year. This is important because it provides a much clearer insight into how producer price expectations have changed over time, compared to observations of annual average prices paid which include prices under contracts of various vintages.

Key conclusions from the Oakley Greenwood report were as follows:

— East coast average wholesale gas prices (excluding transmission) rose from $7.60/GJ in 2015 to $9.78/GJ in 2016, before easing back to $9.19 in 2017.

[7] The term 'LNG netback' refers to the selling price of LNG minus the costs associated with liquefaction and shipping. It can be thought of as the price at which an economically rational producer would be indifferent between selling to domestic consumers or directing gas to an LNG plant.
[8] Australian Competition and Consumer Commission, "Inquiry into the East Coast Gas Market", April 2016, p.24.

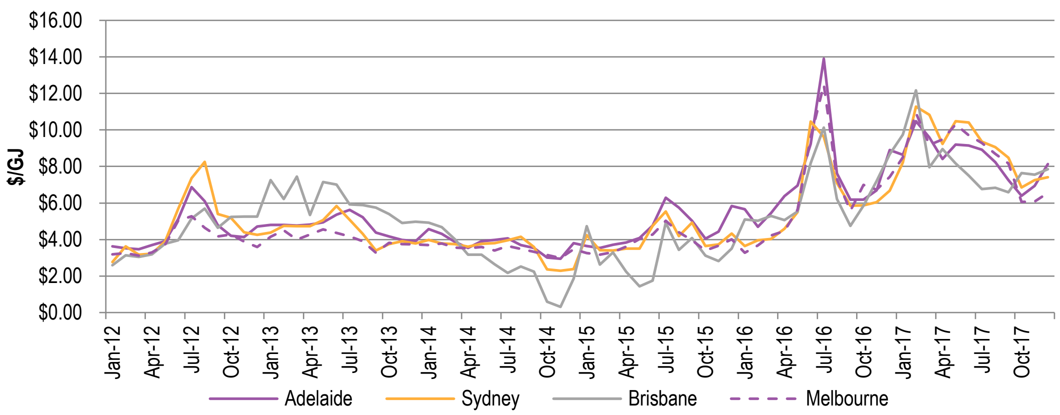
— The highest wholesale gas prices in 2016 and 2017 were observed in Victoria, at $10.67/GJ and $10.00/GJ respectively.
— The lowest wholesale gas prices in 2016 and 2017 were observed at Gladstone, at $7.36/GJ and $7.00/GJ respectively.
— Industrial gas prices in Queensland fell by 11% over the period 2015 to 2017, while the corresponding prices in Victoria and Tasmania rose by 78 per cent and 60 per cent respectively.
— Wholesale gas prices in Western Australia moved in the opposite direction to prices in south-eastern Australia, falling from $8.17/GJ in 2015 to $5.00/GJ in 2017.

The fact that industrial wholesale gas prices fell in Queensland while at the same time they rose sharply in Victoria and Tasmania strongly suggests that the price rises in southern Australia were not directly attributable to the Gladstone LNG plants, but rather to a lack of competitive supply alternatives in the southern markets.

Spot prices

Figure 2.3 shows average monthly spot gas prices in the Victorian Declared Wholesale Gas Market and the Short Term Trading Markets in Adelaide, Sydney and Brisbane over the period January 2012 to December 2017.

FIGURE 2.3 EASTERN AUSTRALIA AVERAGE MONTHLY SPOT GAS PRICES



SOURCE: ACIL ALLEN COMPILATION OF AEMO PRICE DATA

The data demonstrates a significant degree of correlation between the spot markets in Eastern Australia.

For a period in the lead up to first LNG production at Gladstone, the highest sport gas prices were observed in Brisbane and Sydney. However, during 2014 (up to the time of commissioning of QCLNG Train 1) prices in these markets fell to very low levels as excess 'ramp gas' entered the market with Queensland CSG production being brought on line ahead of LNG start-up. Following the commissioning of QCLNG Train 1 in late 2014 spot prices in all markets began to trend strongly upward.

In mid-2016 spot gas prices rose to very high levels driven by severe winter conditions in southern markets combined with an outage on the Heywood electricity interconnector between Victoria and South Australia. This confluence of events saw peak gas demand in South Australia reach record levels, while both gas and electricity prices soared. Another price peak, somewhat lower, was seen in the summer of 2017 driven by increased gas demand associated with closure of the Hazelwood coal-fired power station in Victoria. Prices have since retreated to more 'normal' levels but remain well above historical norms.

2.3.2 Gas prices in Western Australia

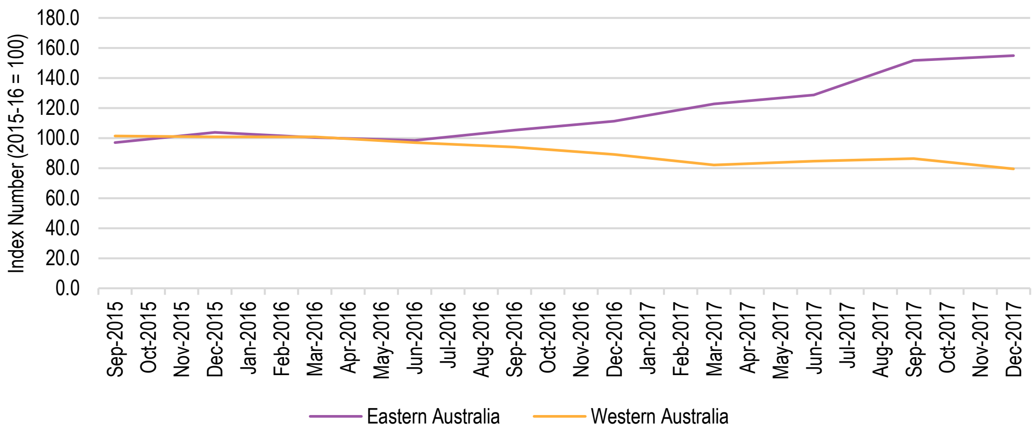
Contract prices

Data published by AEMO shows that in 2016–17, real quarterly gas prices in Western Australia averaged $5.13/GJ, compared to $5.87/GJ in Eastern Australia[9]. According to the same source, gas prices in Western Australia increased by 19 per cent from 2012–13 to 2016–17.

The Oakley Greenwood study referred to above found that Western Australia's industrial consumer gas prices for new contracts declined over 30 per cent from 2015 to 2017, and that wholesale gas could be secured for under $5/GJ in 2017. The difference between the AEMO and Oakley Greenwood data reflects that fact that AEMO is reporting the average price for all gas sold each quarter (total sales revenue divided by total sales volume) irrespective of when the sales contracts were written, whereas Oakley Greenwood reported the price of new contracts in the relevant period.

The Australian Bureau of Statistics (ABS) now publishes a quarterly Producer Price Index (PPI) for gas extraction in the Australian domestic gas markets, with data starting from 2015. This output price index measures changes in the price of gas purchased from producers through bilateral contracts. As shown in **Figure 2.4**, the gas extraction producer price index in Western Australia has fallen from 101.4 in September quarter 2015 to 79.5 in December quarter 2017. Over the corresponding period, the gas extraction producer price index in Eastern Australia rose strongly from 97.0 to 154.9.

FIGURE 2.4 PRODUCER PRICE INDEX – GAS PRODUCTION



SOURCE: ABS CAT.NO. 6427.0

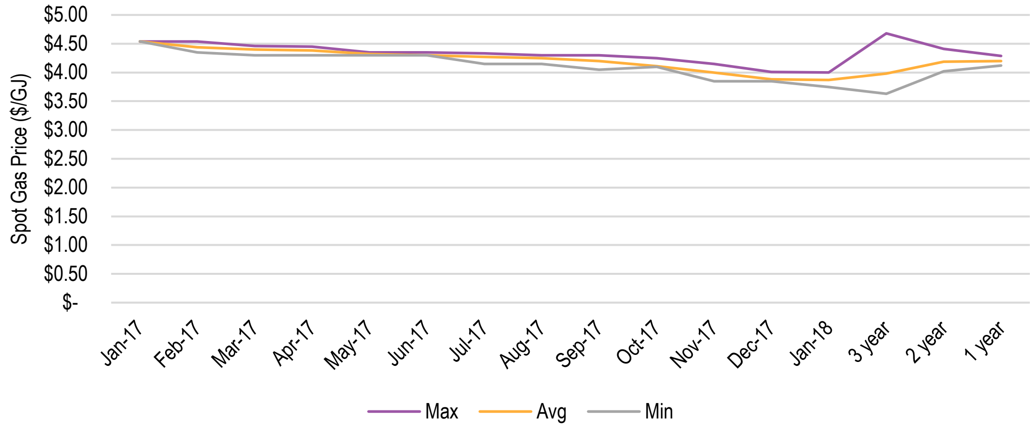
Spot prices

Western Australia does not have a centralised spot or short-term trading hub comparable to the Short Term Trading Markets operating in Eastern Australia. Only a very small proportion of gas sales (around 1 per cent of total volumes) in Western Australia are traded through spot and short-term platforms.

The only information in the public domain regarding the price of spot or short-term gas is provided by a private organisation, gasTrading Australia Pty Ltd, which posts data on spot prices and volumes on its website. **Figure 2.5** shows maximum, minimum and average spot gas prices published by gasTrading Australia. Over the past year, average spot gas prices in Western Australia have traded in a narrow range with a consistent downward trend. Spot prices fell from an average of about $4.55/GJ in January 2017 to $3.85/GJ in January 2018.

[9] AEMO, 2017: Gas Statement of Opportunities for Western Australia, p. 20.

FIGURE 2.5 WESTERN AUSTRALIA AVERAGE MONTHLY SPOT GAS PRICES



SOURCE: HTTP://WWW.GASTRADING.COM.AU/SPOT-MARKET/HISTORICAL-PRICES-AND-VOLUME/13-HISTORICAL-PRICES-AND-VOLUME/27-PRICE-HISTORY-TABLE

The data also shows that spot prices have been relatively weak for some time, having averaged just under $4/GJ for the past three years.

2.4 Options for increasing gas supply in Eastern Australia

There are a number of options to address the current tight gas supply situation in Eastern Australia and the resultant potential for gas supply shortfalls to arise over the next few years. These options are not mutually exclusive. In the medium term, increased gas supply could come from several sources including:

— new conventional gas field developments in Eastern Australia
— new unconventional gas developments in Eastern Australia
— re-direction of gas from Queensland LNG plants
— supply of gas from the Northern Territory
— importation of LNG
— supply of gas from Western Australia.

The options are discussed in turn below.

2.4.1 New conventional gas field developments in Eastern Australia

There are numerous conventional gas field development prospects in Eastern Australia that could be developed, some of which are well advanced. For example, the **Sole** project in the offshore Gippsland Basin is currently under development and will provide a new source of domestic gas capable of delivering up to 25 PJ per year from 2019. Other potential conventional field developments based on known gas fields and advanced prospects include:

— the **Manta** gas-condensate field (30 km southwest of Sole; Cooper Energy 100 per cent; 106 PJ of 2C Contingent Resource) with an indicative start date of 2022–23
— the **South East Remora** and **South East Longtom** in the eastern Gippsland Basin, discoveries made by the GBJV partners in April and November 2010
— the **Dory** prospect, a poorly defined but potentially very large prospect in the south-eastern Gippsland Basin. There has been some media speculation that the Dory field could contain up to 2,000 PJ of gas with associated condensate
— gas-fields in the vicinity of the BassGas project in the Bass Basin, including the **Rockhopper** and **Trefoil** fields
— the **La Bella** gas and condensate field and the **Flanagan** gas prospect in the offshore Otway Basin

- the **Haselgrove** gas discovery (January 2018) in the South Australian part of the onshore Otway Basin
- numerous small gas discoveries, mostly close to infrastructure, in the South Australian **Cooper Basin**.

Further exploration in response to perceived market opportunities and price signals may yield additional new projects but the size and timing of such developments remains uncertain. Declining levels of exploration expenditure following the oil price collapse in mid-2014, together with restrictive policies in relation to onshore exploration in New South Wales and Victoria reduce the prospects for further conventional exploration success in the short to medium term.

2.4.2 New unconventional gas developments in Eastern Australia

The term ‘unconventional gas’ includes coal seam gas (CSG), shale gas and so-called ‘tight gas’ contained in low permeability reservoirs, often in over-pressured basin-centred accumulations.

As indicated in **Table 2.1** there are very large prospective resources of unconventional gas (of the order of 80,000 PJ identified) in tight, basin-centred gas accumulations in the Cooper Basin. The Beetaloo Sub-basin in the Northern Territory is regarded as highly prospective for shale gas. The very large CSG reserves associated with coal seams in the Surat and Bowen Basins of central and southern Queensland are well-established and have been brought rapidly into production to support the Gladstone LNG projects as well as continuing to supply domestic markets. Geologically similar coal measure sequences occur in New South Wales with the Gunnedah and Sydney Basins being analogous to the Bowen Basin and the Clarence-Moreton Basin an analogue of the Surat Basin. These areas have established CSG reserves but are sparsely explored with very little on-going work because of current State government policies.

At present, efforts by petroleum companies to commercialise new sources of unconventional gas supply (in particular coal seam gas and shale gas) in Eastern Australia are constrained by restrictive State and Territory government policies including a moratorium on onshore petroleum exploration drilling (conventional and unconventional) in Victoria; government buy-back of CSG exploration titles and land-use constraints in New South Wales; and a moratorium on the use of hydraulic fracture stimulation for shale gas appraisal and development in the Northern Territory.

Nevertheless, unconventional gas developments such as the proposed **Narrabri CSG** project in New South Wales have the potential to make very significant contributions to domestic gas supply in the medium to long term. As currently planned, Narrabri CSG could supply up to 200 TJ/d of base load gas into the Eastern Australian market.

2.4.3 Re-direction of gas from Queensland LNG plants

In mid-2017 the Australian Government introduced a policy mechanism (the Australian Domestic Gas Security Mechanism, ADGSM) under which the government could limit quantities of gas being exported as LNG to boost supply to domestic markets. At this point in time the ADGSM has not been triggered, with the Queensland LNG producers having given undertakings to provide additional gas to the domestic market to avoid any short-term supply shortfall. In the longer term the Queensland LNG producers are likely to continue to supply significant quantities of gas into the domestic market, particularly during seasonal peak demand periods, both in response to commercial price signals and to avoid the political and public sanctions that they might otherwise face in the event of serious supply shortfalls.

In this context it is relevant to note that the total rate of gas feed into the three Gladstone LNG plants, operating at nameplate capacity, is of the order of 4,000 TJ/d. Freeing up just 5 per cent of this gas feed would result in up to 200 TJ/d of supply to the domestic market, covering more than 10 per cent of Eastern Australian domestic demand.

2.4.4 Supply of gas from the Northern Territory.

Jemena is constructing the Northern Gas Pipeline between Tennant Creek and Mount Isa. This pipeline will initially be capable of supplying up to 90 TJ/d of gas from the Northern Territory into the Eastern Australian market at Mount Isa. Initially the pipeline will transport gas supplied by Power and

Water Corporation (PWC; Northern Territory Government) from its Blacktip (offshore Bonaparte Basin) contract entitlements. In the longer term, the Northern Gas Pipeline could carry gas from the Beetaloo Basin or other unconventional prospects in the onshore regions of the Northern Territory, subject to successful exploration following a resumption of onshore exploration and development activity after the Northern Territory Government's scientific inquiry into hydraulic fracturing is completed.

In order to deliver large quantities of gas from the Northern Territory to the main Eastern Australian demand centres, there would be a need for further investment in infrastructure to expand the Northern Gas Pipeline and to provide additional transport capacity downstream of Mount Isa. It should, to a large extent, be possible to stage such investment to meet emerging market opportunities, without the need for large infrastructure investments ahead of demand.

2.4.5 Importation of LNG

AGL is currently investigating the importation of LNG into Eastern Australia to supplement local domestic supply. It has identified a preferred site for a receiving terminal at Crib Point in Victoria. Feasibility studies are continuing. If the project proceeds, AGL has stated that it could see importation of around 100 PJ of LNG per year from 2021–22.

More recently (February 2018) the *Australian Financial Review* reported that a joint venture called Australian Industrial Energy (AIE) is investigating the feasibility of constructing an LNG import terminal in New South Wales, at Port Kembla, Port Botany or Newcastle. The joint venture—comprising major Australian and international companies including Squadron Energy, Marubeni, Tokyo Electric, Chubu Electric and GE—is considering investment of up to $300 million on securing, connecting and fuelling a floating re-gasification terminal that would be capable of delivering up to 100 PJ/a into the domestic market. This is similar, in terms of cost and size, to AGL's Victorian proposal. The AIE proposal also contemplates a new 750 MW gas-fired power station that would be fuelled from the import terminal.

Both the AGL and AIE proposals involve use of ship-borne Floating Storage and Regasification Unit (FSRU) technology which is now well-established; the International Gas Union *2017 World LNG Report* lists 23 FSRU vessels currently chartered.

The economics of setting up and operating an FSRU-based LNG import terminal in Eastern Australia are yet to be clearly demonstrated. However, analysis by ACIL Allen suggests that with an annual leasing cost of US$50 million per year spread over gas deliveries of 100 PJ/a, and an average LNG buying cost of US$7.30/mmbtu (which was the average price of LNG spot sales in Japan for calendar 2017), a delivered cost of gas of A$9–10/GJ may be achievable.

Other potential advantages of LNG import solutions are that they can be pursued on a relatively low capital cost basis by leasing the FSRU vessels. Relatively low capital cost means that they do not require long payback periods that need to be supported by long-term contractual commitments.

2.4.6 Pipeline supply of gas from Western Australia

The Australian Government indicated in April 2017 that it would consider supply of gas from Western Australia to the Eastern States via a West–East Pipeline as a possible means of improving energy security and affordability. This pre-feasibility study is directed toward assessment of this response option.

2.4.7 Comparison of options for increasing gas supply in Eastern Australia

It is not within the scope of this pre-feasibility study to carry out detailed assessments of each of the identified options for augmenting gas supply in Eastern Australia in order to compare the relative merits of the various options. As previously indicated, those options are not necessarily mutually exclusive. It is quite possible—indeed likely—that the future gas supply mix in Eastern Australia will incorporate a combination of these prospective supply sources.

Table 2.2 highlights some of the advantages, disadvantages, risks and opportunities associated with the various incremental supply options and discusses how other options could affect the prospects for a West–East Pipeline.

TABLE 2.2 COMPARISON OF INCREMENTAL GAS SUPPLY OPTIONS.

Supply option	Lead time	Supply potential	Advantages	Risks/ challenges	Risks for West–East Pipeline
West–East Pipeline	6 years plus; possible market opportunity late 2020s	~200 PJ/a	'Nation building' project; potential regional spill-overs; integrated national gas market	$5 billion plus project; 20-year plus payback; need to gain producer commitment; market aggregation; commercial alignment	NA
New EA conventional gas supply	Variable; 4-years plus for new greenfield developments	Variable, most likely in 10–50 PJ/a range.	Brownfield step-out from established infrastructure; aggregation of smaller individual projects	Exploration risk; low oil prices; high development costs	Progressive erosion of WEP customer base resulting in loss of critical mass
New EA unconventional gas supply	Long, likely 5-years plus	Variable, phased build up, potentially very large	Potential to unlock major new resource base	Policy constraints; exploration risk; technology risk; low oil prices; high cost structure; uncertain break-even economics	Progressive erosion of WEP customer base resulting in loss of critical mass
NT shale and pipeline expansions	Long, likely 5-years plus	Variable, phased build up, potentially very large	Potential to unlock major new resource base	Policy constraints; exploration risk; technology risk; low oil prices; high cost structure; uncertain break-even economics; infrastructure capex	Potential to undercut delivered price of gas from WA; erosion of customer base resulting in loss of critical mass
Queensland LNG diversion	Short – immediately available	Short-term (seasonal) peak supply potentially >100 TJ/d; long term structural supply may be more limited	Established production, essentially no lead time. Political and public opinion advantages from being 'part of the solution'	Not cheap gas – LNG netback equivalent. Long-term LNG delivery commitments need to be met.	Potential to defer/delay customer appetite for long-term commitment to pipeline
LNG Import Terminals	Medium; 2-4 years	Up to about 100 PJ/a per terminal	Relatively low cost (~$300M); volume flexible with spot cargoes; access most competitive traded gas supply; relocatable	LNG spot price risk could compromise project economics	Could provide long-term alternative that would undermine the customer base for pipeline

SOURCE: ACIL ALLEN CONSULTING ANALYSIS

2.5 Conclusions regarding the problem diagnosis and possible solutions

Eastern Australia faces a short-term gas supply problem and may face a long-term gas supply problem.

The short-term problem is that, owing to a lack of competitive gas supply alternatives, gas consumers in South-eastern Australia are currently facing sharply rising prices. Some large gas users have been reporting difficulties in securing gas supply offers at any price. This problem has been particularly apparent in Victoria and Tasmania, and to a lesser extent in South Australia and New South Wales.

Constrained gas supply and rising gas demand in the electricity generation sector also mean that there is a short-term risk of physical supply shortfalls that could result in curtailment of gas deliveries to some customers. This is the risk identified and quantified by AEMO in its September 2017 *Gas Statement of Opportunities Update*—a risk that has abated to some extent according to the ACCC's December 2017 assessment. The rapid change in the ACCC assessment, between September and December 2017, emphasises just how quickly the short-term supply–demand balance can shift in the Eastern Australian market, and how much influence the LNG plants at Gladstone can have on that balance.

The potential long-term problem facing the Eastern Australian gas market is one of insufficient reserves replacement. Put simply, there may not be enough new economically-recoverable reserves of gas discovered in Eastern Australia and brought into production to replace declining reserves in existing fields.

The short-term problem facing the Eastern Australian gas market requires solutions that can be deployed quickly and that can be unwound if longer-term structural solutions are found.

The West–East Pipeline cannot address the short-term problem because it is a long-term solution, with a long lead time. It would take several years to complete the necessary planning, approvals, route acquisition, commercial agreements, procurement and construction processes before the first gas could be delivered via the West–East Pipeline. It would involve a large capital investment—more than $5 billion for the pipeline and associated facilities alone—with a long pay-back period. While it may offer energy security benefits by introducing a new gas supply alternative for the east coast market, potentially at stable prices not subject to oil price volatility, it is a long-term solution not well-suited to dealing with a short-term and possibly transient problem.

The most likely solutions to the immediate problem of high prices and constrained supply will be a combination of new incremental supply from established production regions such as Bass Strait, together with some re-direction of gas from the Queensland LNG projects into the domestic market.

There are several alternatives for dealing with the potential long-term problem of insufficient reserves replacement. The West–East Pipeline offers one means of bolstering long-term gas supply in Eastern Australia. There are several other options, including new conventional gas fields in the Gippsland, Bass, Otway and Cooper Basin areas; shale gas developments in the Northern Territory supported by new pipeline investment; tight gas developments in the Cooper Basin; CSG developments in New South Wales and Queensland; or LNG imports.

All these options face challenges and none is assured. Whether or not they will, individually or collectively, be able to fully address the looming supply gap in Eastern Australia remains to be seen.

The West–East Pipeline faces some major challenges that will be difficult to overcome, particularly while other, lower cost and more flexible options remain in prospect. However, if these alternatives do not emerge in time to address the issue of securing long-term gas supply for the Eastern States, the West-East Pipeline could emerge as the best available option. For this reason, it would make sense to keep that option open.

2.5.1 A 'real options' approach

A 'real options' approach to decision making involves maintaining a set of alternative decision pathways that allows flexible adjustments to changing circumstances. There are costs associated with establishing and maintaining each option, but the investment is justified by the opportunity to lower the risk of incurring high costs by prematurely locking into decisions that prove to be sub-optimal. Real options approaches are particularly valuable for decision making under conditions of uncertainty, because they provide decision-makers with flexibility to adjust their position as new information comes to hand.

The energy market in Eastern Australia is a good candidate for applying real options approaches because it is a highly uncertain decision-making environment. There are many variables that may affect future gas supply, demand and pricing in Eastern Australia, each of which has the potential to impact significantly on investment decisions. For example, we cannot be sure about the extent and timing of entry of new gas supply sources such as NT shale gas, NSW CSG or LNG imports. Neither can we be sure about levels of future industrial demand for gas, the extent of gas-to-electricity fuel switching among retail customers, or the amount of gas that will be needed for electricity generation. A real options approach to decision making allows us to keep various response options on foot while gathering more information to better inform our final decisions and to reduce the lead times between investment decisions and project completion. This can allow locked-in decisions to be made later and with less risk of adverse market developments occurring after lock-in has occurred.

A sensible real options approach to dealing with the longer-term issue of security of gas supply for the Eastern Australian market would involve maintaining the option to proceed, or not to proceed, with the West-East Pipeline at a future date by undertaking prudent low-cost preparatory activities. Such activities would advance the project and help to reduce its delivery timeframe, while deferring for as long as possible any irrevocable commitment to major capital expenditure.

Some of the early, low cost activities that might be undertaken include:

— on-going monitoring of alternative sources of gas supply, and assessment of the relative positioning of the West–East Pipeline among those options
— work to better define potential gas supply sources and the technical and commercial requirements for their delivery
— market soundings to test customer interest in purchasing gas from the project and the commercial terms on which such sales might be transacted
— pipeline route investigations aimed at optimising the pipeline corridor and identifying important physical, environmental, heritage and socio-economic constraints and opportunities
— establishing baseline environmental monitoring along the pipeline corridor
— community and stakeholder consultation in potentially affected areas along the pipeline route
— steps to secure and maintain access to the pipeline corridor
— consideration of alternative ownership structures
— consideration of alternative funding models.

Further discussion regarding possible ways forward that would keep the West–East Pipeline option open, together with recommended actions, is set out in Chapter 10.

3 STAKEHOLDER ENGAGEMENT

Consultation with the key stakeholders, including state and territory governments, gas producers, pipeline operators and major gas users, was an important step to ensure that all relevant information and viewpoints were taken into consideration in determining potential sources of gas, assessing pipeline route options, identifying potential corridor constraints and assessing the alternatives available to east coast gas users.

3.1 Stakeholder engagement process

As part of the pre-feasibility study process, ACIL Allen and GHD consulted with key stakeholders, including state and territory governments, gas producers, pipeline operators and major gas users to inform the study findings.

Stakeholders were provided with a Consultation Guide providing background information on the study, and the matters that we were looking to address. To ensure that the consultation interviews were as productive as possible, a series of questions was developed on issues that the project team wished to discuss (see Appendix A). Not all stakeholders were able to respond to all questions: we sought considered responses to those questions relevant to each organisation and emphasised a willingness to receive input on any other relevant matters not covered by the questions set out in the Consultation Guide.

Where possible, consultations were conducted on a face-to-face basis with representatives of both ACIL Allen and GHD meeting with the stakeholder representatives. Where face-to-face meetings could not be conveniently arranged, meetings were conducted by teleconference. A small number of stakeholders provided written submissions in confidence.

A member of the project team took notes during each of the consultation interviews. These notes were compiled to assist in the formulation of project assumptions and other elements of the engagement as required. The notes of interviews have not been provided to the Department of the Environment and Energy or to any other party, nor do they form part of this report. Any commercially sensitive information provided by stakeholders has been treated as confidential. The report does not attribute specific statements to any individual or organisation without explicit prior consent.

3.2 Stakeholder organisations and consultations

Invitations were sent to some 54 organisations inviting their input to the consultation process. ACIL Allen Consulting and GHD conducted interviews with and/or received submissions from a total of 36 stakeholder organisations over the period November 2017 to January 2018. The stakeholder organisations consulted have been grouped into four groups, as shown in **Table 3.1**, to provide a cohesive perspective from stakeholders rather than presenting individual interests. Individual government responses have been identified where their comments are addressing the position of each government.

TABLE 3.1 LIST OF STAKEHOLDER ORGANISATIONS CONSULTED

Producer organisations	Pipeline organisations	Consumer organisations	Government & regulatory organisations
Australian Petroleum Production and Exploration Association	APA Group	AGL	Australian Energy Market Commission
Buru Energy	ATCO Australia	Asia Pacific LNG[1]	Australian Energy Market Operator
Chevron Petroleum	Australian Gas Infrastructure Group (inc. Dampier-Bunbury Gas Pipeline; Australian Gas Networks, Multinet).	Australian Energy Council	Australian Government Department of Industry, Innovation & Science
ConocoPhillips	Australian Pipeline and Gas Association	Chamber of Commerce and Industry Western Australian	Economic Regulation Authority (WA)
Mitsubishi	Epic Energy	Dow Chemical	Gas Market Reform Group
Quadrant Energy	Jemena	Energy Australia	Geoscience Australia
Woodside		Fortescue Metals Group	Northern Territory Government
		Origin Energy	NSW Government
		Queensland Curtis LNG[1]	Queensland Government
		Santos[1]	South Australian Government
		Shell	Victorian Government
			Western Australian Government

Notes: 1. APLNG, Queensland Curtis LNG and Santos (on behalf of GLNG) are both producers and purchasers of gas. From the perspective of the West–East Pipeline they are categorised as consumers.

3.3 Consultation themes

Through the consultation process, five key themes emerged across the issues and challenges raised by stakeholders. These were:

1. **Market-related risks:** centred on concerns regarding the long-term nature of the project, risks to East Coast demand.
2. **Sources of gas supply:** centred on the identification of potential sources of supply, and challenges related to the current exploration climate, and potential emergence of competitive alternative supply sources.
3. **Role for Government:** centred on the “nation building” nature of the project, ways governments could be involved in the project, and risks associated with government underwriting.
4. **Regulatory risks:** centred on the framework for economic regulation, the identification of regulation and approvals required, and the timing of a project of this scope.
5. **Routing considerations:** centred on the identification of key considerations for route selection, including lift off points and sources of demand on route.

3.4 Theme One: Market risks

3.4.1 Potential for a West–East Pipeline to address Eastern Australia supply issues

There was general recognition that a West–East Pipeline was at least a theoretical option to alleviate the risk of gas supply shortfalls and to improve energy security in Eastern Australia. One **gas buyer** suggested that supply from WA would eventually be needed because the east coast states would not be able to sustain their gas output based on current rates. Another noted that:

'If you can ensure supply post 2020 the pipeline is no longer a pricing game … the entire dynamic of this project changes from simply trying to achieve the lowest price of gas to become focussed on securing supply as gas reserves deplete and become less reliable'.

It was also noted that the introduction of a new competitive source of gas would be welcome, commenting that producer power was currently a major concern in Eastern Australia:

'If there is only one source of gas, the pipeline owners can't help retailers with price manipulation from the gas supplier.''

It was also suggested that a transcontinental pipeline, accessing the East Coast market, could be good for Western Australian industry because it would 'incentivise gas into the WA domestic market'.

One large **gas consumer** argued that construction of cross-country, open-access, regulated natural gas pipelines and storage was key to improved market access to bring the most price-competitive resources to market. They argued that moving forward with a cross-country pipeline was a 'necessary and defining endeavour' that required action now to avoid disruptive intervention later.

However, there was little support for the idea that a West–East Pipeline was likely to be the best, least-cost option for bolstering Eastern Australian gas supply. The more general view was that a West–East Pipeline was not currently needed or justified. The following comments reflect this position:

'It's a long-term development that won't occur in the next 10 years' [Pipeliner]

'It is a project that wouldn't even be a part of our screening process for potential projects' [Gas buyer]

'It has been looked at a number of times in the past and there was a general view that demand was not sufficient to underwrite a pipeline.' [Government agency]

'The construction of a west–east pipeline could assist to improve natural gas supply and reliability nationally, but we expect its viability to be challenged economically.' [Regulatory organisation]

Despite the widely-held view that the need for a West–East Pipeline was likely to be some time off, there was recognition of the long lead time that would be involved. One **pipeliner** noted that construction would take years and that permitting was likely to add more years to the overall development timeframe, meaning that planning for the pipeline might have to commence soon even though supply shortfalls might be at least five years off.

Government stakeholders recognised that the pipeline could make a valuable contribution in terms of improving security of supply to the east coast. They noted that the large amount of line pack gas that would be contained in the pipeline could provide flexibility that could be attractive to existing market participants. However, they questioned whether LNG importation might not provide a more cost-effective alternative.

Government sources noted that linking the Western Australian gas market to the east coast market potentially bought with it both positives and negatives, particularly given Western Australia's gas prices have historically been a source of competitive advantage. It was also noted that current projections suggest Western Australia will be in a domestic gas shortfall by the mid-2020s (the precise timing of this differed by agency) based on declining production from current sources of supply.

3.4.2 Key market risks

All stakeholder groups were quick to point out what they considered to be the most significant challenge of this project: the significant demand risk a potential supplier or group of suppliers, and the pipeline owner, would be required to take on to be involved in the project. Their concerns were wide ranging and related to other themes raised in the following sections of this chapter.

Producers, pipeliners, gas buyers and government agencies all raised a series of concerns regarding future demand and competing supply sources, including:

— Competing gas being found closer to the source of demand, particularly in the event State-level bans on unconventional gas exploration were lifted.

— Potential development of an LNG import terminal. This was widely regarded as a realistic possibility. It was seen to be a relatively low capital cost option involving a much shorter-term commitment, capable of delivering large quantities of gas and with an ability to utilise the most competitively priced gas sources available internationally, rather than locking into a single [Western Australian] supply source that may not prove to be the most competitive supplier in the long term.
— Potential fuel substitution, particularly by renewable energy and battery storage technologies, displacing gas as a source of baseload power generation in Eastern Australia.

Some stakeholders saw these concerns as interacting to create an overall environment of uncertainty. For example, one **producer** remarked:

'For us, risks to the east coast market are substantial; moratoriums lifted, additional gas from the NT, LNG producers feeding more gas into the domestic market. We put this big infrastructure in and expect a supplier to underwrite it, and that's fine, but then it can all be taken away with the stroke of a pen.'

Stakeholders thought these concerns could be ameliorated by long term take or pay contracts. However, they were generally sceptical regarding the appetite of purchasers to take long-term contracts that would incentivise a new development. Most thought that the project would need 20-year contract commitments, but that buyers would not be willing to take on such long-term risks. They noted that there had been a shift away from long-term contracts to much shorter arrangements, typically no more than three years. One major gas buyer commented that:

'I cannot recall the last time we saw a 15 to 20-year supply contract executed [in the domestic market]'

Another summed up the challenge as follows:

'Trying to aggregate the loads for the West–East Pipeline based on the uncertainty faced by customers today would make the demand incredibly hard to lock in.'

Government stakeholders also recognised that long term contracts would be needed to entice market participants into a stable investment. They saw a need to test the willingness of offtake partners to sign 20-year deals given current market dynamics and the trend to short term contracts. They recognised that the pipeline would face major challenges in securing demand up front and locking in contracts to purchase gas from the first day of operation.

One **government** stakeholder pointed to the risk that rational decision making could be distorted by politically-motivated decisions to subsidise the project:

'Government might call it national building and securing supply, but whether we really need it is another point and whether it is the most cost-effective option for securing supply. Just because the West–East Pipeline is a national building project doesn't make it feasible. Comparative economics needs to be taken into account [but] comparative economics get thrown out of the window if the government subsidises the project.'

Producers were mindful that, to provide the required capital and operating commitments, a pipeline operator would need to reduce or eliminate demand risk on a project of this scale. **Pipeliners** were also wary of demand side risk, noting it would be difficult to charge a tariff that would make it a competitive option for addressing gas supply challenges without a long-term contract or multiple long-term contracts.

Producers, pipeliners and **consumers** all noted that large commercial and industrial (C&I) customers were important to underwrite the volumes that would be needed to justify the project, but that they were also the most price sensitive customers. One stakeholder commented that C&I customers were likely to want prices, including delivery, less than $8/GJ. It was also noted that C&I customers were particularly at risk of exiting the market because of higher gas prices, and that perversely the exit of some C&I customers could relieve the current tightness in the market and see gas prices fall, thereby eroding the opportunity for the pipeline. One party summed up the problem as follows:

You get to a total delivered gas cost where you can't get businesses to remain viable such as chemicals and fertilisers. These businesses are the ones which require larger long-term contracts to underwrite security … If these C&I customers decide to shift operations offshore, the long-term contracts *associated with the industry will not be available and the West–East Pipeline will not be able to be underwritten.*

On fuel substitution and the impacts of renewable energy and battery storage technologies, **pipeliners** raised fundamental questions about the long-term future for natural gas, pointing to the possibility that existing pipeline systems would convert to transportation of alternative low-carbon energy fluids such as hydrogen-based fuels. One **government** representative pointed to a recent decision by a large industrial consumer to shift a significant part of its energy load from natural gas to renewable energy as a real-life example of fuel substitution risk in action.

3.4.3 Potential buyers

It was widely recognised that the delivered price to consumers would be the key to attracting potential buyers and achieving the required levels of market penetration to support the pipeline.

One **gas buyer** said that if a price around $7.50/GJ could be achieved going into Moomba, they would strongly consider the project. However, they would only be interested in contracting for around five years and, even then, would want volume flexibility built into the contract. Their view was that a 10-year contract 'wouldn't be on the radar' as it would pose too much risk in terms of both volume and price. Another gas buyer said that they would consider a long-term contract 'if the right opportunity came up' but that 'the price would have to be heavily discounted to market prices'.

Producers, pipeliners and **consumers** all saw the Gladstone LNG plants as the customers most likely to enter into long-term offtake agreements, noting the long tenor of their LNG sales contracts and pointing to the fact that no other parties are currently contracting long term. However, they also queried the logic of piping gas across the country to turn into LNG, rather than directing it into LNG plants in Western Australia.

3.5 Theme Two: Sources of gas supply

A key consideration in the minds of stakeholders, when asked for their views on availability of Western Australian gas supply, was the current state of the Western Australian gas market. As **government** stakeholders pointed out, the domestic market in Western Australia is currently forecast to be short of gas within five years. One **gas buyer** in Western Australia said:

'We're worried about post-2023, concerned about NW Shelf plateau and exactly how much gas that will produce. In terms of our ability to contract beyond that, we can't do it. Suppliers appear to be waiting to see how that will play out'.

Producers noted that there had been very limited offshore exploration activity since the peak of the resources investment boom, given world energy prices and a general view that the easiest-to-access gas resource has already been tapped.

Producers were nearly uniform in their view that a new source or multiple sources of supply would need to be developed to provide feed gas for a West-East Pipeline. There was no appetite to divert gas from existing fields away from LNG or outside of the domestic Western Australian market. However, they thought that developing a new large-scale source of supply to support the pipeline would be challenging, for a few reasons:

- The current moratorium on hydraulic fracturing in the Canning Basin (as part of a State-wide moratorium, excluding in the Perth, Peel and South West regions where a permanent ban has been put in place), which had set back the development of prospective reserves in the Canning Basin.
- The lack of offshore exploration in recent years, which would take some time to turn around.
- The prospective change in operating model of the North West Shelf LNG facility, and associated pipeline from the Browse Basin to the facility as a means of unlocking that field. There was a view that this was a likely outcome, but there remained significant challenges to realising it.

One producer remarked:

There's no cheap gas there [in the Carnarvon Basin]. Some of the gas that is closer [to shore] is much drier – there is very little condensate. There is probably other gas out there, but nobody is drilling and *it's been a long time. So: lots of gas, none of it is cheap, difficult composition, a lot of it with no condensate.*

Producers also said that the ACCC's position regarding joint marketing would make it difficult for new and marginal fields to proceed to production in a way that would be able to meet a notional production target of 500TJ/day, because most of the current fields are relatively small.

Other prospective fields were 'medium' scale which meant they were too big for the domestic market in Western Australia but not large enough to justify a new LNG train or to backfill an existing LNG train. It was considered fields like this would be the ideal size to support a West-East gas pipeline.

Stakeholders pointed to the fact that there was a lot of stranded gas in the north-west. However, development of fields in the Browse Basin was seen to be very challenging. One **gas buyer** referred to it as a 'white space development' with no infrastructure or amenity in place to underpin any offshore supply point, meaning that exploitation of these reserves would require the simultaneous development of a pipeline and a major offshore development.

ACIL Allen and GHD sought **producer** views on the marginal ex-field cost of gas for a new development. **Producers** were reluctant to provide precise estimates but noted the Browse and Scarborough fields were the most prospective. As a general indication, a price of around $6/GJ was suggested. **Producers** with existing production were clear in their views that the marginal cost was relatively high. On the other hand, **producers** with prospective production were more confident that the marginal cost of production was sub-$6/GJ. One **gas consumer** thought that gas in the Canning Basin was likely to cost $6/GJ at the wellhead, making it difficult to commercialise:

'To get US-style costs, you need to have US-style markets and we don't have that. A transcontinental pipeline could help spur onshore gas development, but not the other way around.'

It was recognised that the cost of gas into the pipeline would be a critical determinant of project economics. On the question of the prices that producers might accept for their gas, one **producer** said the price setter for the WA domestic market was likely to be the Perth Basin, where onshore producers were looking to expand production for the domestic market. Another pointed to the need to pay gas prices with netback in the future 'unless there is a government intervention such as price caps or quantity caps in the form of a reservation policy'. There was, however, recognition of the fact that producers may consider the value of bringing forward monetisation of resources:

The key question is to look at the next best alternative. This next best alternative should be analysed through the lens of acceleration economics … bringing tail gas forward in time in addition to balancing the upfront capex costs.

A technical issue raised by one producer was whether West Australian gas would match Eastern Australian gas specification standards. While this was not seen as a fundamental obstacle, it was noted that differences in specification could result in additional processing costs.

Pipeliners and Government organisations did not provide a perspective on resource potential, other than to raise the current state of supply and demand in Western Australia as discussed above.

On the topic of potential emergence of competitive alternative supply sources, several stakeholders pointed to the risk posed by new sources of supply in the Northern Territory and the Eastern States, particularly if current restrictive policies were changed. The Beetaloo Basin in the Northern Territory was seen by **producers, pipeliners** and **gas buyers** as having strong prospects and potentially offering a more competitive source of supply that would undercut the economics of a West–East Pipeline.

One **gas buyer** also pointed to the Narrabri CSG project in New South Wales as another new supply source that was likely to proceed.

3.6 Theme Three: Role for Government

Producers and pipeliners struggled to 'see a world where the pipeline would be able to exist without heavy government support'. Several noted that if the case for the pipeline stacked up commercially it would have already happened without government support. Given this, stakeholders provided their perspectives on the ways in which the Government could become financially involved in the project. These included:

- **Exploration incentives** to spur investment in the development of new fields which would be able to provide the initial source of supply for the pipeline.
- **Up-front funding contributions**, either as a pipeline owner or a large grant or equity injection to a private pipeline owner, to help lower the up-front capital hurdle and to assist in de-risking the project.
- A role for Government to **take on the demand risk**, through a demand aggregation role or as holder of a long term take-or-pay contract.
- A role for Government to **directly subsidise** the transport tariff payable by purchasers, or to guarantee a pipeline owner's rate or return through an operating subsidy.

A **gas buyer** noted that:

'Government has options; there is a market failure. One approach is to regulate it into being – incentivise the investment. Other way is financial assistance or subsidies. We'd prefer the regulatory approach, like to see all private money funding a pipeline of this nature. It should stack up.

The regulatory regime would be really important. A lazy response from government would be just to stump up the money. There's no shortage of money in the world looking for infrastructure returns'.

However, one **pipeliner** thought it 'highly unlikely' that the project could rely on government to underwrite large contracts.

Most stakeholders were aware of the multiple considerations of the Commonwealth Government in this project, raising the spectre of its **nation building** status. Stakeholders raised this in the context of discussions as to how the Government should be involved in the project, suggesting again there was a view it would be unviable without some form of direct government assistance.

The **Western Australian Government** flagged its willingness to assist in the facilitation of a West-East gas pipeline, subject to it meeting the State's interest and the Domestic Gas Reservation Policy (where 15 per cent of all gas that is bought on shore in Western Australia is provided to the domestic market in some way). This would include support through the approvals process.

Another **government representative** noted that government backing for the West–East Pipeline could create disincentives for domestic exploration gas. They thought that, while it could be good from a consumer point of view at least initially, there was a need to recognise that subsidising the pipeline would tend to back out higher risk exploration onshore.

In this regard we note a similar experience in New Zealand where the existence of a long-term, large-volume, low-priced Crown Contract that underpinned the establishment of the Maui gas pipeline had the effect of supressing further investment in gas exploration.

3.7 Theme Four: Regulatory risks

Stakeholders raised several regulatory considerations for a pipeline development of this nature. While stakeholders saw significant regulatory barriers, there was no suggestion that they could not be overcome. They were more concerned about market-related risks when considering the overall viability of the pipeline.

The regulatory risks raised by stakeholders included native title, environmental approvals, economic regulation and gas market reform policies, renewable energy policies, restrictive exploration and production policies, and gas reservation policies. These are discussed in turn below.

3.7.1 Native Title

All stakeholder groups in Western Australia raised native title as the number one regulatory issue. In Western Australia, native title claims must be settled before any other regulatory approvals processes can be commenced. Some **producers** indicated they had little trouble securing native title agreements, while others indicated that securing agreements had been challenging.

Pipeliners were concerned about the number of title groups involved in an approvals process for the pipeline, given it was linear infrastructure that would stretch across the country, and about the potential for protracted negotiations and blocking tactics.

Government stakeholders also raised native title as a key regulatory issue, although the **Northern Territory Government** suggested it would be a relatively straightforward process in its jurisdiction due to the existence of overarching Land Councils to assist project proponents. The **Western Australian Government** indicated that the level of complexity involved in resolving native title claims was variable.

3.7.2 Environment approvals

The main issue raised regarding environmental approvals was the length of time required to complete the approvals processes. The **Western Australian Government** suggested it would take between 18 months and two years to complete its Environmental Protection Authority process, which could only commence once native title had been addressed along the whole pipeline route. This would mean that, if a pipeline development was to begin today, the earliest construction could commence would be 2022.

3.7.3 Economic regulation and gas market reform policies

Lower risk due to gas market reform: Regulators, most **government representatives** and **gas producers** tended to characterise the pipeliner and gas buyer concerns around the recent Section 23 reforms, as ‘overstated’. They saw the reforms as important steps in improving transparency and liquidity in Australia's gas markets, enhancing market efficiency, lowering costs and facilitating the movement of gas across the transmission network. They pointed to the levels of new gas transportation contracts announced by pipeline companies, and to ongoing investment in new capacity (for example the Northern Gas Pipeline, currently under construction; the Reedy Creek Pipeline in southern Queensland and proposed developments of new infrastructure to tie gas fields the North Bowen and Galilee Basins of central Queensland into the east coast market.

Higher risk due to gas market reform: Pipeliners, **gas buyers** and some **officials** thought that recent and on-going gas market policy reforms with the introduction of Part 23 of the National Gas Law would significantly increase the commercial risk of investment in the pipeline and could ultimately affect its bankability. Two areas of recent policy reform were singled out: the new **arbitration and information disclosure** regime, and arrangements for **compulsory auctioning** of contracted but un-nominated pipeline capacity. However, despite these concerns, several of the same stakeholders acknowledged that new pipeline projects were still being sanctioned and that investment in new pipelines was still occurring.

Some **pipeliners** saw the arbitration framework as the biggest risk, arguing that it gives shippers the option to trigger arbitration with nothing to lose. They thought it would impact on the bankability of projects, potentially reducing the willingness of market participants to enter into foundation contracts, increasing levels of commercial risk and pushing up the cost of capital (debt and equity), which would in turn flow through to higher tariffs. All else being equal, they thought these factors would increase the cost of gas delivered via the West–East Pipeline, reducing its competitiveness and its ability to achieve critical market mass.

Some **pipeliners** and **gas customers** also saw the compulsory capacity auction arrangements as an important new area of risk. They thought that the auction process would discourage shippers from entering into long-term foundation contracts and believed that it would strongly incentivise pipelines to build to the bare minimum capacity.

One **pipeliner** said that it would not consider investment in the West–East Pipeline without long-term (15-year) exemptions from from the information disclosure and arbitration requirements of Part 23 of the National Gas Rules, and from the capacity auctioning arrangements currently under development.

A **large gas buyer** said that the auction arrangements were causing high levels of uncertainty for foundation shippers, commenting that:

'Regulatory risk is too high [for us]. We will not be positioned in the near to medium term to underwrite any potential pipelines. Rule changes are now occurring too frequently, so that we are not sure what we would be underwriting.'

The issue of multiple jurisdictions was also raised as a complicating factor. It was noted that a West–East Pipeline would potentially come under the control of both the Western Australian Economic Regulation Authority and the Australian Energy Regulator. It was suggested that a cross-border pipeline may fall under Commonwealth jurisdiction (ACCC/AER) as happened in the past (for example, with the Moomba–Sydney Pipeline), but that the question of jurisdiction would need further investigation.

3.7.4 Renewable energy policies

Stakeholders were particularly wary of the potential impact of renewable energy policies on the long-term market outlook for gas on the east coast of Australia.

Producers suggested that the Commonwealth Government should look beyond a transnational pipeline as a solution to east coast energy challenges and instead look at how its overall policy environment—centred on renewable technology subsidies—may be contributing to market instability.

3.7.5 Restrictive exploration and production policies

Many stakeholders raised the uncertainty created by restrictive gas exploration and production policies such as the moratoria on hydraulic fracturing in Western Australia and the Northern Territory as a key regulatory concern. While there was a general view that both governments would ultimately allow unconventional gas production in their jurisdictions, the delays and uncertainties caused would make it difficult to chart a picture of potential sources of supply. As discussed in section 3.4, **producers** were also concerned about the potential for future easing of restrictions and moratoria in Northern Territory, New South Wales and Victoria and the negative impact on West–East Pipeline demand that this may cause if new supply sources in these areas prove to be more competitive.

3.7.6 Gas reservation policies

Both **producers and government agencies** raised the Western Australian Government's domestic gas reservation policy as a potential issue for procurement of gas supply into the West–East Pipeline. There was some confusion over whether the reservation policy would apply to gas not earmarked for LNG, with some stakeholders suggesting that all gas brought on shore has the 15 per cent Western Australian obligation applied to it. The question of freedom of trade between States was raised, with one stakeholder expressing doubts as to whether the Western Australian government could prevent 'reservation gas' being sold interstate.

3.8 Theme Five: Routing considerations

The final theme gathered together the perspectives provided by stakeholders regarding route selection. Some of these considerations are related to the four previous themes, while others are more specific to route selection itself. By way of introduction, the 'straw man' lift off and delivery points for the pipeline were presented to stakeholders as Dampier or Broome (for lift off) and Moomba or Adelaide (for delivery), with no actual route map shown.

3.8.1 Alternative routes

Most stakeholders supported examination of the identified lift off points. During consultation with the **Western Australian Government**, it was noted that any proposed gas development near Broome was likely to involve sensitive political issues relating to environmental and cultural heritage matters. One **producer** suggested shifting to 'Derby', but it was noted there were significant maritime challenges at Derby related to tidal range which made it very challenging to use as a supply base.

When speaking with **producers** there was a clear alignment between the location of a producer's fields and/or existing infrastructure and their preferred lift off point. For instance, prospective onshore gas producers selected Broome/Derby as the logical lift off point, whereas offshore producers favoured Dampier.

It was suggested that the pipeline would need to start at Compressor Station 1 on the Dampier–Bunbury Natural Gas Pipeline because this is the interconnection point for gas from the Varanus Island, Gorgon and North West Shelf projects. It was pointed out that a connection into the Goldfields Gas Pipeline would not have access to sufficient capacity to achieve the targeted delivery volumes.

Regarding the alternative delivery points, most stakeholders regarded Moomba as more likely to provide a viable route alternative because it would maximise market access, particularly for the large Gladstone LNG loads. A Moomba terminus was also seen as offering the advantage of access to existing processing, compression and underground storage facilities. It was also pointed out that Moomba would allow ethane to be extracted from the West–East Pipeline gas stream and then transported via the existing dedicated ethane pipeline to Sydney. The access to storage, in particular, was regarded as a key advantage of the Moomba option. However, some stakeholders were wary of the potential imposition of additional processing fees at Moomba, which they thought might compromise project economics.

It was also pointed out that both the Moomba to Adelaide Pipeline and the Moomba to Sydney Pipeline have capacity restrictions due to their age and condition, and that additional investment might be required to overcome these restrictions.

Adelaide was generally seen as offering too small a direct market with most of the gas delivered via the West–East Pipeline having to be diverted back to Moomba. However, there was some support for the Adelaide option, as well as for routes further north, through the Amadeus Basin and to Tennant Creek.

It was generally acknowledged that an Adelaide terminus would offer the potential to deliver gas directly into the Victorian market (via back haul on the SEA Gas pipeline). One **producer** highlighted the security of supply benefits to the South Australian market that an Adelaide delivery would offer, pointing to pipeline integrity issues on the ageing Moomba–Adelaide Pipeline (MAP) as a security of supply risk. While we agree that having a third gas transmission pipeline servicing the Adelaide market would undoubtedly enhance security of supply in South Australia, we note that integrity issues on MAP may pose a significant commercial risk to the West–East Pipeline—particularly in a configuration terminating at Adelaide—because the West–East Pipeline will rely on MAP for onward carriage of a significant part of its throughput.

One **pipeliner** suggested that, if the Northern Territory government maintains the current ban on hydraulic fracturing, connection into Tennant Creek could be a viable option because a Karratha to Tennant Creek route would be much shorter and could be supported by brownfield expansion of the Northern Gas Pipeline. A route from Karratha to Moomba via Alice Springs (Amadeus Basin) was also advocated, although another **pipeliner** noted that the route from Alice Springs to Moomba would be very difficult to construct.

3.8.2 Mid-line opportunities

Government sources in Western Australia were positive about potential mid-line sources of demand, raising a nickel/potassium production province in the eastern Goldfields and potential mines in the Browns Range region (near the SA and NT borders) as potential energy loads. Otherwise, current mines were adequately served by existing gas pipelines or did not represent an attractive source of demand on route.

Government representatives indicated that there was unlikely to be any material demand for gas along the route if it was to pass through the Northern Territory. The Northern Territory Government was, however, interested in any discussions regarding a route through northern Australia connecting with the Northern Gas Pipeline (at Tennant Creek).

In South Australia, **government** and **pipeline** representatives pointed to the potential for an Adelaide-terminating pipeline to service future oil and gas exploration areas *en route*, as well as mines (Olympic Dam) and undeveloped mineral prospects in the Gawler Craton region.

Discussions highlighted the fact that **Geoscience Australia** has comprehensive databases on mineral occurrences and prospectivity, as well as web portal tools that could be of considerable assistance in the evaluation of route options and identification of mid-line development opportunities that could benefit from access to energy.

While stakeholders generally saw the merit in considering mid-line opportunities, they did not see them as being primary drivers of the project. As one **government** representative put it:

'Regional benefits [from providing mid-line access to energy] would not be the drivers of the project, but … the benefits would be salient in the business case'.

3.8.3 Route alignment and access issues

Pipeliners pointed to route alignment and the lead times associated with gaining land access as critical issues for project timing. They also highlighted the logistical challenges of construction of a very long, large diameter pipeline through such a remote area, including the large number of heavy vehicle movements that would be required for pipe delivery and positioning.

The most significant route consideration raised related to native title claims. Stakeholders encouraged ACIL Allen and GHD to give a high weight to native title considerations in their assessment of route options, noting that there was potential for some claims to be more complex than others. It was also noted that avoiding routes with a large number of competing claimants would potentially assist in expediting development.

Stakeholders encouraged ACIL Allen and GHD to consider using existing infrastructure corridors, including major interstate highways, railway lines or existing pipeline easements, where possible. It was suggested that existing infrastructure corridors would provide an advantage in terms of logistics supply chains, noting that pipeline construction would require facilities such as workers accommodation, water and food to be available along the entirety of the route. However, it was pointed out that there was some uncertainty regarding the native title status of some existing infrastructure corridors, particularly roads, which may add to the complexity of the project.

The Western Australian Government also pointed out that the Square Kilometre Array project, in the Mid West region of the State, was a radio quiet zone and that is was unlikely that any pipeline construction could occur in that region.

Constraints around the Woomera Prohibited Area in South Australia were noted.

4 MARKET MODELLING

4.1 Market assessment of route alternatives

Detailed market assessments were undertaken for four route options:

- Route 1 – Dampier (Carnarvon Basin) to Moomba
- Route 2 – Dampier (Carnarvon Basin) to Adelaide
- Route 3 – Broome (Browse & Canning Basins) to Moomba
- Route 4 – Broome (Browse & Canning Basins) to Adelaide

For each route option, ACIL Allen's *GasMark*® model were used to assess the ability of WA gas, delivered via the West–East Pipeline, to penetrate the Eastern Australian market.

The *GasMark* model is a long range economic model that attempts to match supply and demand in each of the regional gas markets in Eastern Australia and Western Australia with the dual objective functions of:

- minimising the cost of gas to consumers; and
- maximising field netbacks to producers (delivered price less transport costs).

The model incorporates assumptions about current and future gas supply (reserves, production rates and minimum selling prices), gas demand at individual customer or customer group level (annual quantity, price tolerance) as well as existing and possible future transmission pipelines (current capacity, future expansions, tariffs).

The *GasMark* model user interface map for the West–East Pipeline Route 1 (Dampier – Moomba), illustrating the gas fields, pipelines, demand centres, storage and LNG facilities represented in the model, is illustrated in **Figure 4.1**. As shown, the pipeline has been evaluated in the context of a relatively detailed characterisation of the Western Australian and Eastern Australian gas markets.

A more detailed explanation of the *GasMark* model is set out in Attachment B.

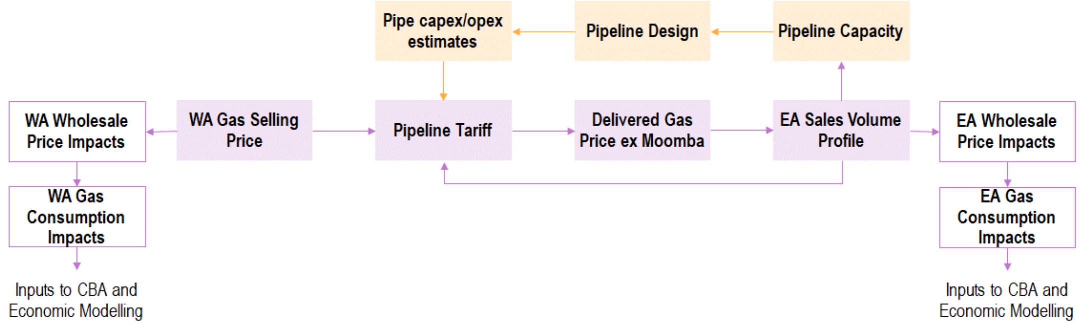
FIGURE 4.1 GASMARK MODEL INTERFACE FOR WEST–EAST PIPELINE STUDY (ROUTE 1)

SOURCE: ACIL ALLEN GASMARK MODEL

Different assumptions regarding the prices at which gas could be supplied into the pipeline from WA supply sources and the tariffs required to support commercial operation of the pipeline (return on and of capital and recovery of operating costs) were used to establish a range of market penetration profiles. These profiles were then used, in combination with the capital and operating cost estimates prepared by GHD, to refine the pipeline design, costings and estimates of commercially sustainable pipeline tariffs. The aim was, through this iterative process (illustrated diagrammatically in **Figure 4.2**), to identify the most prospective current route option and then to establish, for that route option, an internally consistent, optimised design basis in which the pipeline configuration and costing is matched to a gas delivery profile that is realistically achievable given the price at which gas can be delivered into the Eastern Australian market.

The market modelling provides time-series projections (at annual resolution) of wholesale gas prices at key market nodes in both Western Australia and Eastern Australia, as well as projections of gas consumption and production. Comparing these modelling results against the corresponding Reference Case outcomes allows estimation of the differential effects of the various route options on gas production, consumption and price. These differential impacts are key inputs to the Cost Benefit Analysis and CGE Economic Modelling.

FIGURE 4.2 GAS MARKET MODELLING FRAMEWORK



SOURCE: ACIL ALLEN CONSULTING

4.2 Reference Case assumptions

Assumptions regarding gas demand by customer sector, existing and future alternative sources of gas supply, gas transmission pipeline capacities and tariffs, and LNG plant feed gas requirements for both the Eastern States and Western Australia reflect ACIL Allen's current 'Reference Case' assumptions. This case represents a reasonable mid-line scenario based on the current market situation and recent developments in relation to key market drivers. For eastern Australia it corresponds broadly with the Australian Energy Market Operator (AEMO) Neutral scenario as set out in the 2016 National Gas Forecasting Report. For Western Australia, current supply and demand assumptions reflect data published by AEMO on the Gas Bulletin Board WA.

The Reference Case assumptions take into consideration recent market developments including:

— The continued weakness in oil prices which has impacted on the pace of ramp-up of Gladstone LNG production and severely curtailed exploration for unconventional gas in central Australia.

— Implications of the Northern Gas Pipeline linking the Northern Territory and eastern Australian gas markets from 2018.

— Closure of coal-fired power stations in South Australia and Victoria.

— Firming up of the Sole gas project as a significant new source of supply from the Gippsland Basin, with production expected to commence during the first half of 2019.

4.2.1 Reference Case assumptions – Eastern Australia

Reference Case: Global Assumptions

The following global assumptions are incorporated into the Reference Case:

— Consumer Price Index (CPI) of 2.5 per cent per year.
  – The Reserve Bank of Australia (RBA) and the Australian Government have adopted a long-term inflation target of 2 to 3 per cent. 2.5 per cent is therefore the mid-point of the RBA and Government target range.[10]
  – ABS data (6401.0 Consumer Price Index, Australia) shows that over the past 25 years (comparing quarterly data from March 1991 with previous corresponding periods) the average annual rate of inflation has been 2.54 per cent.
  – Adopting a 2.5 per cent inflation rate for the gas modelling maintains consistency with the electricity market modelling from which the demand values for gas-fired power generation that are included in the gas model have been derived. ACIL Allen's electricity market modelling routinely assumes an inflation rate of 2.5 per cent.

— Long-run oil price of US$60/barrel

[10] See http://www.rba.gov.au/inflation/inflation-target.html which states that "The Governor and the Treasurer have agreed that the appropriate target for monetary policy in Australia is to achieve an inflation rate of 2–3 per cent, on average, over the cycle."

- Long-run exchange rate 0.75 USD/AUD
- LNG price (delivered) = ((0.135 x Oil Price US$/bbl)/Exchange Rate + US$1.5)/1.055 = A$12.15/GJ. The 0.135 slope assumption in the pricing formula is broadly in line with most analyst reports that assume the Gladstone LNG price (in US$/mmbtu) to be equal to the oil price (Japanese Customs Clearance, JCC in the Asian region) multiplied by 0.13 to 0.14, plus a small fixed component. Historically, price slopes for LNG pricing contracts have ranged between about 0.10 and 0.17, with the latter representing full energy equivalence to oil.
- No explicit carbon pricing arrangements. However, from 2020 the assumed levels of gas use for electricity generation reflect an assumption that an implicit carbon pricing mechanism is reintroduced.
  - There remains uncertainty around carbon policy over the longer term. Although the Emission Reduction Fund (ERF) and safeguard mechanism are in place currently, they are unlikely to remain in their current format if Australia is to achieve its current 2030 emissions reductions target as this would require, in the absence of the ability to import abatement permits, the closure of additional power generators.
  - The proposed National Energy Guarantee (NEG) is intended to address these objectives. However, the detailed design of the NEG and its implications for gas demand is not yet finalised.
  - ACIL Allen's current electricity Reference Case assumes explicit carbon pricing comes into force from July 2020 at a level of around \$20/tonne CO_2-e escalating in real terms at about 3 per cent per annum. This can be thought of as either a change in policy (introduction of the NEG) or an adjustment to the ERF policy resulting in a lowering of the sectoral baseline and allowing generators to purchase and surrender international permits.
  - The most recent AEMO *National Gas Forecasting Report* (December 2016) assumes a proxy emissions abatement price of \$25/tonne in 2020 rising to \$50/tonne by 2030.

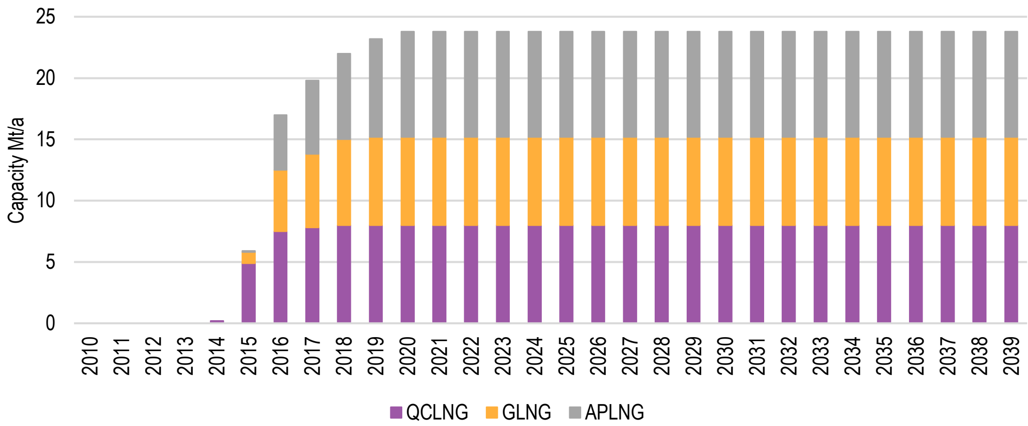
Reference Case: Gas demand

The following assumptions are made regarding gas demand:

- **Retail loads** (residential, commercial and small industrial customers serviced by gas distribution businesses and retail energy sellers) consider information drawn from recent access regulation cases and from AEMO's *National Gas Forecasting Report*. Retail demand, by sector and State, closely reflects the current AEMO forecasts.
- **Large industrial and mining customers** demand projections are based on the known gas requirements of existing large industrial and mining consumers that contract for gas directly, plus gas requirements of any new large industrial or mining loads that we consider to be committed or advanced projects. ACIL Allen maintains a comprehensive database of such customers within the *GasMark* model. We have also cross-checked our industrial gas demand forecasts against the AEMO forecasts of industrial gas demand which include direct surveys of major industrial gas consumers.
- **Gas-for-power generation** (GPG) assumptions are based on ACIL Allen's modelling of the hourly dispatch of individual generating units in the National Electricity Market, with annual gas requirements and daily gas consumption profiles calculated from modelled plant dispatch by applying assumed operating efficiency/heat rate for each plant. In general terms, gas-fired electricity generation is expected to decline sharply from the high levels of 2014–15 and is not projected to recover until after 2025.
- **LNG:** With regard to Queensland CSG LNG projects we assume that liquefaction capacity at Gladstone is limited to the currently committed six trains (nominal 25.3 Mt/a LNG) with each plant operating at a level corresponding to its current LNG contract levels. As a result, the effective output of the six trains is limited to 23.8 Mt/a LNG.

Figure 4.3 illustrates the Reference Case assumptions regarding Queensland CSG LNG plant production capacity.

FIGURE 4.3 ASSUMED LNG PRODUCTION CAPACITY AT GLADSTONE—REFERENCE CASE



SOURCE: ACIL ALLEN GASMARK MODELLING

Reference Case: gas supply

The model includes a set of assumptions regarding existing and future sources of gas supply. For each gas field or group of fields (referred to as ‘field aggregates’) the gas supply dataset includes assumptions regarding available reserves and resources by category, production capacity (including changes in capacity over time) and long run marginal cost (LRMC) of production of gas.

The Reference Case gas supply assumptions incorporate some 108 gas fields and field aggregates, including both existing sources of supply and potential new gas field developments. These supply sources include conventional gas fields, coal seam gas projects and future unconventional gas projects (shale gas, tight gas). Key assumptions in relation to gas supply include the following:

- Total potentially producible reserves and resources of about 169,000 PJ across Eastern Australia and the Northern Territory.
  - The total resource base includes Queensland (75,000 PJ), New South Wales (14,000 PJ), Victoria (14,700 PJ), South Australia (21,000 PJ), Tasmania (500 PJ) and the Northern Territory (44,000 PJ)[11].
- Queensland CSG field developments ramp up with sufficient supply capability to meet Gladstone LNG plant requirements, with modest excess capacity available to support domestic deliveries after an initial ramp-up period.
  - Gas field developments formerly associated with the Arrow LNG Project (now owned by Shell) are assumed to be brought into production in response to market demand, potentially bolstering supply to the current six LNG trains and/or supplying domestic market loads. However, in line with Shell’s 2015 announcement that it would not proceed with the development of its North Bowen Basin fields at this time, we have not assumed any pipeline link between the North Bowen Basin and Gladstone, effectively preventing this production capacity from serving markets outside North Queensland.
- In light of the shutdown of several CSG exploration and development projects in NSW (including AGL’s Gloucester project and Metgasco’s Clarence–Moreton project), we assume no growth in NSW CSG production during the projection period. The existing Camden project is assumed to continue at reduced output until 2023, generally in line with AGL’s announced plans for this facility. We recognise that Santos continues to pursue its Narrabri CSG project in New South Wales. If developed, this project could become a significant contributor to Eastern Australian gas supply, and could compete directly with imports of gas from Western Australia via a West–East Pipeline.
- Recent and new additional sources of conventional gas supply in the Bass Strait region including Halladale–Blackwatch–Speculant (offshore Otway) from 2016; Kipper–Tuna–Turrum (offshore

[11] Includes Ichthys project which lies in Western Australian waters but will be used to produce LNG at Darwin.

Gippsland Basin) from 2017 and Sole (offshore Gippsland Basin) from 2019 are included. We also assume tie-in of additional gas reserves in the Bass Basin (Trefoil, Gentoo/Rockhopper) which extend the production profile for the BassGas Project. 'Yet-to-be-discovered' fields in the offshore Gippsland and Otway Basins are assumed to offer new gas supply, at relatively high cost, with production capacity ramping up over the period 2020 to 2025.

— Cooper Basin unconventional capacity is assumed to be limited to 50 PJ/a by 2022 with all production directed to the Santos – GLNG Easternhaul supply contract to Gladstone.
— With regard to gas supply in the Northern Territory, it is assumed that Amadeus Basin production capacity increases from 4.3 PJ/a in 2016 to 20 PJ/a by 2020. Additional gas resources are found and developed in the Amadeus Basin to support this level of production. Production capacity in the Beetaloo Basin ramps up from 5 PJ/a in 2021 to 50 PJ/a by 2030. Production capacity in the McArthur Basin ramps up from 1 PJ/a in 2021 to 20 PJ/a by 2025. No production occurs in either the Georgina Basin or the Pedirka Basin.

Reference Case: Transmission pipelines

The Reference Case modelling scenario includes a representation of the existing high-pressure gas transmission supply network as well as a number of possible future transmission pipeline connections. Potential new sources of supply in the Northern Territory have been tied into the existing Eastern Australian transmission network at Mount Isa (Jemena Northern Gas Pipeline). For existing pipelines, current capacity constraints have generally been relieved where necessary to allow market growth to occur. This reflects an assumption that transmission pipeline owners will expand capacity provided there is market support for the investment. However, in some instances capacity constraints that are assumed in the modelling may 'bind', resulting in inter-regional price separation. Tariff assumptions for existing pipelines reflect current reference tariffs (in the case of economically regulated pipelines) or publicly posted tariff offerings where available. For potential new pipeline connections and for existing pipelines for which no tariff offerings are publicly available, we have used a simple pipeline economic model to estimate sustainable transport tariffs.

We assume that the Jemena Northern Gas Pipeline (NGP) from Tennant Creek to Mount Isa proceeds with capacity of 90 TJ/day available from the end of 2018.

4.2.2 Reference Case assumptions—Western Australia

The same global assumptions that have been adopted for Eastern Australia (regarding CPI, oil price, exchange rate, LNG price and carbon price) apply to Western Australia. The following assumptions with regard to gas supply/production, gas demand and gas transportation have been made for Western Australia.

4.2.3 WA gas production

Continuing production based on current production levels and known reserves/resources for:

— North West Shelf Karratha domestic gas supply to a maximum of 630 TJ/d, reserves limited
— Reindeer/Caribou fields (Devil Creek) domgas to a maximum of 220 TJ/d, reserves limited
— Varanus Island fields including John Brookes, Halyard/Spar to a maximum of 345 TJ/d, reserves limited
— Macedon to a maximum of 231 TJ/d, reserves limited
— Perth Basin, including development of Waitsia field to a maximum of 100 TJ/d by 2020. Reserves limits apply to individual fields.

New domestic gas supply from:

— Gorgon domgas, increasing to 300 TJ/d by 2020
— Wheatstone domgas at 200 TJ/d from mid-2018

The following LNG production facilities are included in the mode:

— NWS LNG at up to 16.3 million tonnes per year
— Pluto LNG at up to 4.3 million tonnes per year

- Gorgon LNG at up to 15 million tonnes per year
- Wheatstone LNG at up to 8.9 million tonnes per year
- Prelude LNG at up to 3.5 million tonnes per year from 2018–19 (no connection to domestic market)
- Ichthys LNG at up to 8.9 million tonnes per year by 2019–20 (no connection to domestic market)

It is assumed that no supply from the LNG facilities into the Western Australian domestic market is possible at levels above the associated domestic gas capacity (if any).

4.2.4 WA gas demand

Current Western Australian gas demand has been assumed at levels consistent with the data on large customer gas consumption published by AEMO on the WA Gas Market Bulletin Board, and with small customer demand in the retail sector as reflected in various analysis published by the WA Economic Regulation Authority for the Mid-West and South-West Gas Distribution Systems. For large industrial loads associated with mining and minerals processing industries, demand is assumed to continue at around current levels throughout the modelling period unless there is specific information available regarding committed expansions or contractions in output. This effectively implies that, whereas reserves depletion will mean that some of the existing mining operations are likely to reach the end of their operating lives during the modelling period, these will be replaced by new mine developments based on reserves yet to be brought into production.

4.2.5 Pipeline tariff assumptions

For existing pipelines, current capacity constraints have generally been relieved where necessary to allow market growth to occur. This reflects an assumption that transmission pipeline owners will expand capacity provided there is market support for the investment. However, in some instances capacity constraints that are assumed in the modelling may 'bind', resulting in inter-regional price separation.

Tariff assumptions for existing pipelines reflect current reference tariffs (in the case of economically regulated pipelines) or publicly posted tariff offerings where available. For potential new pipeline connections and for existing pipelines for which no tariff offerings are publicly available, we have used a simple pipeline economic model to estimate sustainable transport tariffs.

4.3 Modelling scenarios

As indicated in section 4.1, we have undertaken detailed modelling of the performance of the West–East Pipeline under four route options:

- **Route 1** – Dampier (Carnarvon Basin) to Moomba
- **Route 2** – Dampier (Carnarvon Basin) to Adelaide
- **Route 3** – Broome (Browse & Canning Basins) to Moomba
- **Route 4** – Broome (Browse & Canning Basins) to Adelaide

For each of these alternative routes, annual flows on the West–East Pipeline were modelled over a range of assumed gas feed prices, from $2/GJ to $10/GJ at $1/GJ steps, to test the ability to penetrate the Eastern Australian market given the alternative sources of supply available and the levels of future gas demand assumed in the Reference Case.

These tests were carried out on the following basis:

- For Routes 1 & 2 only, with gas supply via a 600 TJ/d expansion of the Gorgon domestic gas plant (to total 900 TJ/d), tied into the Dampier–Bunbury Pipeline, not quarantined from the WA domestic market. A Gorgon expansion would not be relevant to Routes 3 and 4 which commence in the north near Broome.
- For all routes, with unlimited production and pipeline capacity made available to the West–East Pipeline, and no effective interconnection to the WA domestic market. The purpose of this case was to test the unconstrained size of the penetrable market in Eastern Australia under different gas price assumptions. All gas price points tested.

— For all routes, with 600 TJ/d of new production and pipeline capacity made available to the West–East Pipeline, and interconnection to the WA domestic market. All gas price points tested.
— For all routes, with 600 TJ/d of new production and pipeline capacity made available to the West–East Pipeline, and no effective interconnection to the WA domestic market. All gas price points tested.
— For all routes, with 600 TJ/d of new production and pipeline capacity made available to the West–East Pipeline, no effective interconnection to the WA domestic market, and with LNG imports into southern Australia at a rate of up to 100 PJ/a from 2020. Mid-range ($5/GJ) price point only tested.

For each of the four route alternatives, the tariff for the West–East Pipeline was set using a simple tariff calculator incorporating the assumptions shown in **Table 4.1**.

TABLE 4.1 ASSUMPTIONS FOR CALCULATION OF WEST–EAST PIPELINE TARIFFS

Parameter	Assumption	Source
Pipe length	As per GHD multi-criteria assessment for each of the Route options	GHD (see **section 6.1**)
Pipe diameter	26 inches	Optimal size as assessed by GHD (see **section 6.1**)
Pipe maximum capacity	600 TJ/d	Target market size, confirmed through consultation process
Pipeline unit construction cost	$70,000 per inch-kilometre	GHD (see **section 6.1.1**)
Compression capex	$550 million (5 stations)	GHD (see **Table 6.1**)
Pipeline O&M annual cost	1.25% of pipe capex	GHD (see **section 6.2.1**)
Compressor maintenance costs	5% of compressor capex	GHD (see **section 6.2.1**)
Compressor fuel consumption	4% of throughput	GHD (see **section 6.2.1**)
Compressor fuel unit cost	$5/GJ	ACIL Allen assumption
System Average Load Factor	80%	ACIL Allen & GHD assumption (see **section 6.2.1**)
Project life	25 years	ACIL Allen assumption
Target Rate of Return (real, pre-tax)	8%	ACIL Allen assumption
Revenue basis	80% of available capacity firm contracted over operating life of pipeline	ACIL Allen assumption

SOURCE: ACIL ALLEN CONSULTING

Two other route alternatives were also tested, but were not modelled in depth:

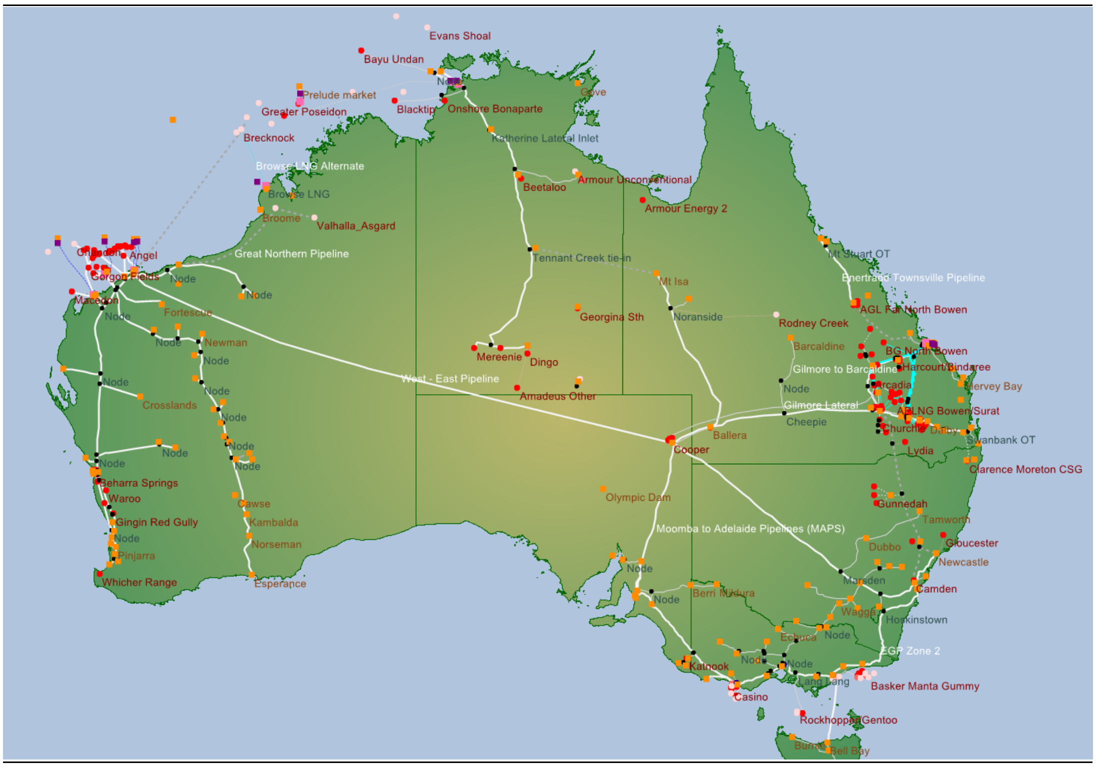
— A **Northern Route** in which the West–East Pipeline is built from Dampier to Tennant Creek, linking up with the Northern Gas Pipeline. This required an assumption that the NGP is expanded to 600 TJ/d capacity, and that a new 1,200 km pipeline is built from Mount Isa to Wallumbilla to allow the gas to reach markets outside north-west Queensland.
— A **'Moomba via Amadeus'** route in which the West–East Pipeline is built from Dampier to the Amadeus Basin in the Northern Territory, linking up with a Southern NT Pipeline (SNP) linking the Amadeus Basin to Moomba. This case assumes that the SNP from Amadeus Basin to Moomba is supported by NT gas production from the Beetaloo and Amadeus Basins ramping up to 350 TJ/d over ten years from 2020, with 90 per cent from Beetaloo and 10 per cent from Amadeus Basin.

The modelling results for the four main route alternatives, and the two additional routes, are summarised in the following sections.

4.4 Route 1—Dampier to Moomba

Figure 4.4 shows the location of the West–East Pipeline Route 1 as represented within the *GasMark* model.

FIGURE 4.4 ROUTE 1 LOCATION – MODEL INTERFACE



SOURCE: ACIL ALLEN CONSULTING GASMARK MODEL

4.4.1 Route 1 – Gorgon Expansion case

The first Route 1 case assumed that gas supply to support the West–East Pipeline would be by way of a 600 TJ/d expansion of the Gorgon domestic gas plant (to total 900 TJ/d). The choice of the Gorgon plant was made for ease of modelling: the incremental supply could equally well have been assumed to come from expansion of one or more of the other domestic gas production facilities in the region, including NWS domestic gas, Wheatstone domestic gas, Devil Creek and Varanus Island. No change was made to existing Gorgon domestic gas tie-in arrangements, with gas delivered into the Dampier–Bunbury Natural Gas Pipeline (DBNGP) at or near Compressor Station CS2.

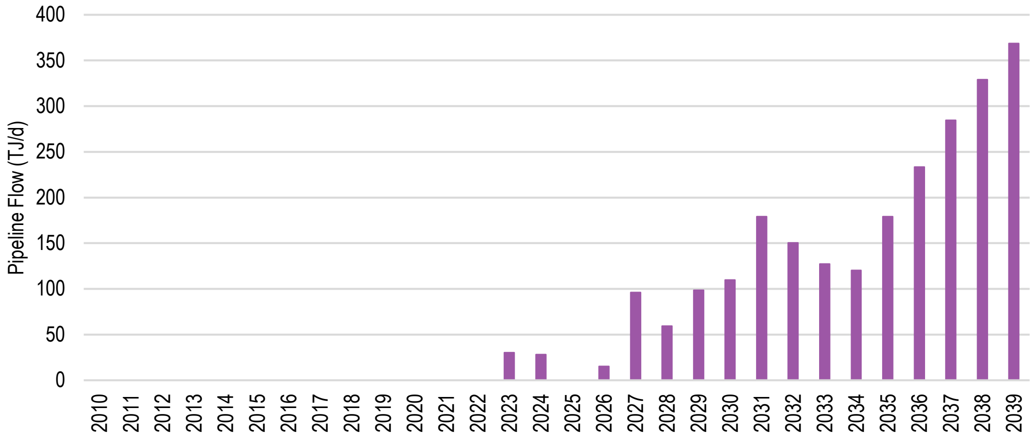
The West–East Pipeline was assumed to be available, with capacity of up to 600 TJ/d, from 2022. The western end of the West–East Pipeline was assumed to tie into the Burrup Energy Pipeline east of Dampier. Gas supplied from Gorgon to the West–East Pipeline would therefore travel via part backhaul on DBNGP and the Burrup Energy Pipeline.

The additional gas supply from Gorgon was not isolated or quarantined from the WA domestic market. It was therefore able to seek market opportunities in Western Australia as well as Eastern Australia via the West–East Pipeline. The default Reference Case assumptions regarding the price at which Gorgon domestic gas is offered into the market were not changed. For this reason, the Gorgon Expansion case was not run across a range of prices.

The rationale for this case was to test the ability of the West–East Pipeline to attract supply away from the Western Australian market on a purely competitive basis, without the incremental gas supply being physically or contractually dedicated to the West–East Pipeline project.

The results are shown in **Figure 4.5**. There is little flow through the West–East Pipeline until 2027. Flows then show a general upward trend, rising steadily from 2034 on. However, net annual flow does not exceed 200 TJ/d until 2036 and reaches a maximum of around 370 TJ/d by the end of the modelling period.

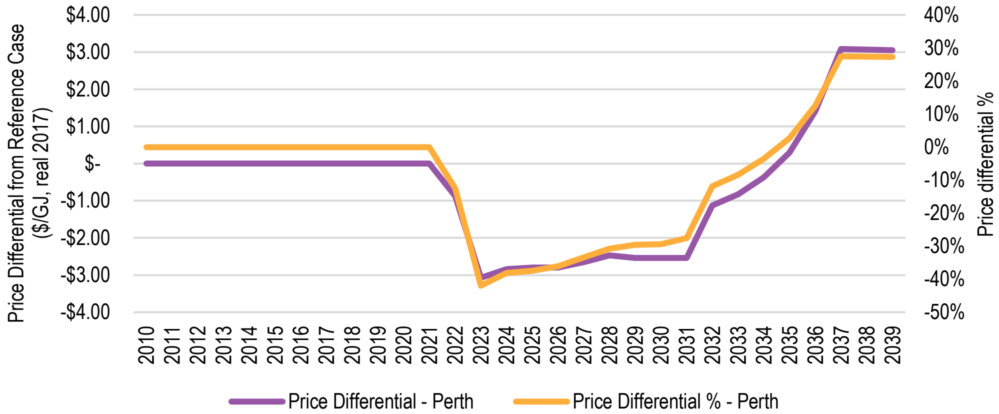
FIGURE 4.5 WEST–EAST PIPELINE ROUTE 1: MODELLED FLOW UNDER THE GORGON EXPANSION CASE



SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

Figure 4.6 shows the effects of the Gorgon expansion case on modelled gas prices in Western Australia (Perth market node). With expanded Gorgon domestic gas competing in the Western Australian market from 2022 prices show a sharp initial fall of around $3/GJ or about 40 per cent when compared to the Reference Case. The price differential reduces over time as more gas is attracted to the Eastern Australian market, and by the end of the modelling period in 2039 prices are up to $3/GJ or about 30 per cent higher than under the Reference Case as local prices are bid up by the connection to the East Coast market.

FIGURE 4.6 PRICE IMPACTS IN WESTERN AUSTRALIA (PERTH MARKET NODE) FOR WEST–EAST PIPELINE ROUTE 1, GORGON EXPANSION CASE



Note: All prices are expressed in real 2017-dollar terms

SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

The modelling results demonstrate that a simple expansion of one or more of the Western Australian domestic gas plants to produce up to 600 TJ/d of additional gas to support the West–East Pipeline, but without any physical or contractual commitment of that gas supply to Eastern Australian supply, would see a large part of the incremental supply taken up in the Western Australian domestic market where it would displace more expensive gas supply alternatives. On this basis, the West–East

Pipeline would not achieve the critical mass of market support required to make the pipeline viable. A smaller pipeline built to match the lower throughput profile would see unit costs rise significantly. As a result, the required pipeline tariff on the West–East Pipeline would increase, pushing up the delivered cost of gas and further eroding throughput volumes.

The results suggest that, to achieve critical mass in terms of gas sales to the Eastern Australian market, incremental gas supply to support the West–East Pipeline will need to be physically or contractually dedicated to the project, effectively quarantining the project and its gas supply from the Western Australian domestic market.

4.4.2 Route 1 – 600 TJ/d capacity, with WA domgas case

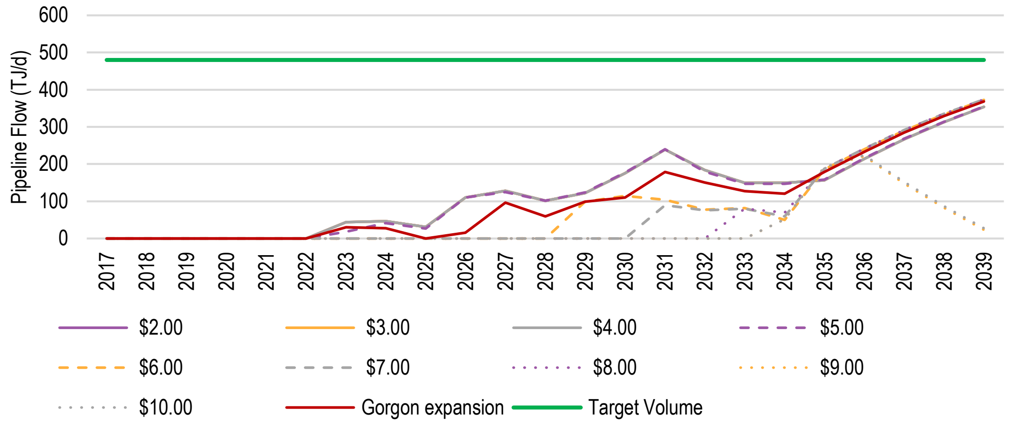
The next Route 1 case assumed that gas supply to support the West–East Pipeline would be provided by way of a dedicated gas production development, with a capacity of 600 TJ/d, that was also connected to and able to sell gas into the Western Australian domestic market via the Burrup Energy Pipeline/DBNGP system.

Based on a pipeline capital cost of $4.73 billion and compressor capital costs of $550 million, plus other assumptions as set out in **Table 4.1**, a West–East Pipeline tariff of $2.91/GJ (real, 2017-dollar terms) was estimated for firm capacity bookings of 480 TJ/d (80 per cent system average load factor).

This tariff was applied to the pipeline in the model, which was then run across a range of gas commodity prices from $2/GJ to $10/GJ at $1/GJ increments.

The results are summarised in **Figure 4.7**.

FIGURE 4.7 WEST–EAST PIPELINE ROUTE 1: MODELLED PIPELINE FLOWS AT DIFFERENT GAS COSTS. 600TJ/D, WITH WA DOMESTIC MARKET CONNECTION



Note: Gas prices are expressed in real 2017 dollar terms

SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

The green line represents an average daily flow of 480 TJ/d which is effectively full utilisation of the 600 TJ/d capacity pipeline at an assumed system average load factor of 80 per cent.

The red line provides a comparison with the results for the Gorgon expansion case discussed in section 4.4.1. The Gorgon expansion results are consistent with the '600 TJ/d, with WA domgas' case at a gas cost of between $5 and $6/GJ.

The results show that, as for the 'Gorgon expansion' case, much of the gas produced from the dedicated gas production development would end up being sold in the Western Australian domestic market, and the West–East Pipeline would not achieve the target rate of throughput at any time during the modelling period, even at low gas prices. This reinforces the finding that, to achieve critical mass in terms of gas sales to the Eastern Australian market, gas supply to the pipeline will need to be physically or contractually quarantined from the Western Australian domestic market.

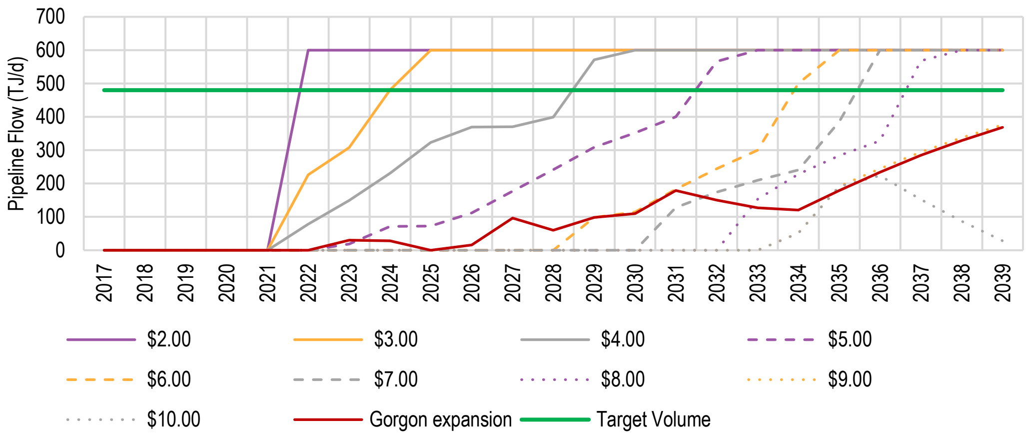
4.4.3 Route 1 – 600 TJ/d capacity, no WA domgas case - most likely scenario

The next Route 1 case is the 'base development case' or in other words the case most likely to lead to a commercially feasible level of pipeline utilisation. Under this case it is assumed that gas supply to support the West–East Pipeline would be by way of a dedicated production development with a capacity of up to 600 TJ/d. This was modelled as a separate gas production field located near the western end of the pipeline. No connection to the Burrup Energy Pipeline/DBNGP system was assumed, with the result that the new supply field was effectively quarantined from the Western Australian domestic market. In practice, there may be physical connection to the main pipeline system (for example, at Compressor Station 1 on the DBNGP) but with the gas supply contractually separated from the WA market by including provisions to prevent re-direction of gas away from the West–East Pipeline.

Other assumptions were the same as for the '600 TJ/d, with WA domgas' case.

The results are summarised in **Figure 4.8**.

FIGURE 4.8 WEST–EAST PIPELINE ROUTE 1: MODELLED PIPELINE FLOWS AT DIFFERENT GAS COSTS. 600TJ/D, NO WA DOMESTIC MARKET CONNECTION



Note: Gas prices are expressed in real 2017 dollar terms

SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

The green line on **Figure 4.8** represents an average daily flow of 480 TJ/d which is effectively full utilisation of the 600 TJ/d capacity pipeline at an assumed system average load factor of 80 per cent.

The results demonstrate that, by quarantining the gas supply to the West–East Pipeline from the Western Australian domestic market, it is possible to achieve the targeted level of market penetration across a range of gas costs. With gas supply at $2/GJ into the pipeline, all available gas is taken up straight away, with the 480 TJ/d average throughput being achieved in 2022, the assumed first year of operation. In practice there would be some delay in achieving this outcome because much of the gas demand in Eastern Australia would be supplied by pre-existing long-term contracts that would have to expire before the new gas supply from Western Australia could be taken up. The *GasMark* model assumes economic efficiency: it does not take account of existing contracts that act to constrain the ability of gas consumers to switch quickly to the cheapest available source of supply when new opportunities emerge.

As the price of gas supply into the pipeline increases, the time taken to achieve targeted utilisation of the system also increases because the delivered price of gas at market locations in eastern Australia becomes progressively less competitive. At $3/GJ the 480 TJ/d utilisation target is reached in 2024; at $4/GJ in 2029; at $5/GJ in 2032; at $6/GJ in 2034; at $7/GJ in 2036; at $8/GJ in 2037; and at $9/GJ or higher the utilisation target is not achieved before the end of the modelling period in 2039.

The red line in **Figure 4.8** shows, by way of comparison, the results for the Gorgon expansion case discussed in section 4.4.1. Even though Gorgon gas is assumed to be offered to the market at a moderate price (around $5/GJ) it does not come close to achieving the target pipeline throughput because much of the incremental Gorgon production is taken up in the Western Australian domestic market, displacing higher-cost marginal sources of supply.

What price are producers likely to sell for?

The above analysis begs a critical question, which is: 'At what price might we reasonably expect that producers in Western Australia would be willing to sell gas into the project?'

During the consultation process we encountered widely differing views regarding the price at which producers would or should be willing to sell. The producers themselves tended to point to rising costs of production and to the need for relatively high prices to justify the investment in exploring for and developing new fields. As a general indication, a price of around $6/GJ was suggested. Producers with existing production were clear in their views that the marginal cost of bringing on new gas supply was relatively high. On the other hand, producers with prospective production were more confident that the marginal cost of production was sub-$6/GJ.

One stakeholder pointed to the forecasts of domestic gas prices contained in the 2017 *WA Gas Statement of Opportunities*, published by AEMO. These show a Base scenario forecast of medium- to long-term average new domestic contract prices (ex-plant) starting at around $5.50/GJ and rising in real terms to $8/GJ by 2027. The corresponding Low scenario price forecast remains at $4/GJ throughout the projection period, while the High scenario starts at $7/GJ and rises throughout the projection period, reaching $11/GJ by 2027.

Some gas consumers argued that gas should be sold at or about the long-run marginal cost of production (LRMC) which they estimated to be in a range of $3 to $4/GJ on average.

In a deep, liquid market with many competing producers and production levels not constrained in the long run by reserves depletion, economic theory suggests that competing suppliers will bid prices down in pursuit of market share, and that prices will therefore tend toward the long-run marginal cost of the marginal producer.

In the past, wholesale gas prices ranging from $3 to $4/GJ were commonplace in Australia. Some gas that was essentially a 'by-product' of oil production was sold at much lower prices because project economics were driven by petroleum liquids and there was a need to produce and sell the gas, at whatever price could be achieved, to optimise liquids production.

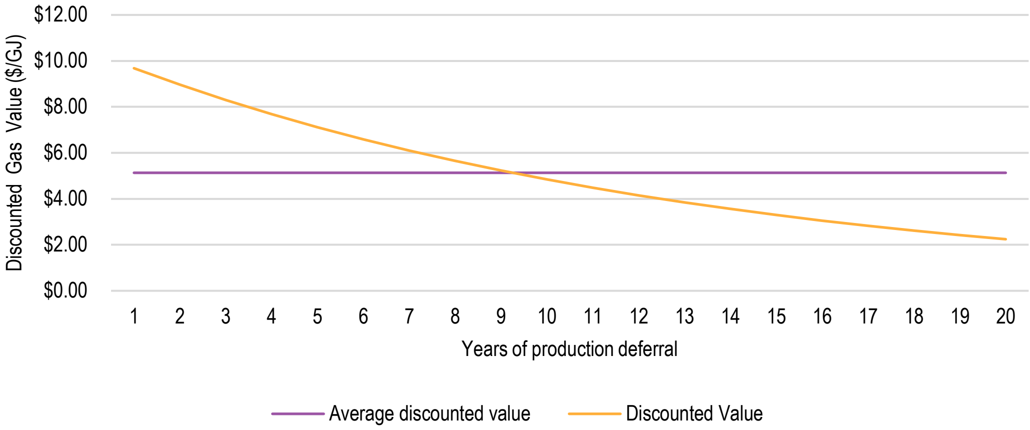
However, a large part of the gas reserves that will be produced in the future have little or no associated liquids. These reserves will only be developed if the prices that they command are able to recover at least their LRMC of production. This is particularly an issue for CSG reserves which typically have no associated liquids.

While there are very large undeveloped gas reserves in offshore Western Australian (Carnarvon and Browse Basins), many of those fields lie in deep water, far from existing infrastructure and are relatively dry. Some have high CO_2 contents. Even priced at LRMC, gas from these fields is unlikely to be economic to develop at prices below $4/GJ.

The Western Australian producers most likely to sell gas into the pipeline project are LNG producers with large reserves and long production timeframes. For these producers, selling gas into the pipeline project may provide a means of accelerating the monetisation of gas reserves that would otherwise be produced much later, toward the end of the LNG project life. Committing gas into the West–East Pipeline project could effectively increase the net present value of those reserves. This is illustrated in **Figure 4.9** which shows how the net present value of a unit of gas delivered into an LNG plant falls over time, depending on the period of deferral of production. In this example, we assume a short-run netback value of gas at the LNG plant gate of about $11.30/GJ.[12] At a discount rate of 8% (real, pre-tax) the net present value of a unit of gas, currently valued at $11.30/GJ but sold in 10 years' time would be $5.13/GJ. In other words, if the producer can bring forward the monetisation of the resource by 10 years by selling the gas to the West–East Pipeline rather than using it to produce LNG, it could achieve the same net present value by selling the gas at $5.13/GJ rather than waiting to get the expected netback value of $11.30/GJ ten years later.

[12] Based on US$70/bbl oil, LNG price slope of 0.135, USD/AUD of 0.8, fixed price component of US$1.50/mmbtu, shipping costs and losses of A$0.75/GJ and variable plant O&M of A$0.75/GJ)

FIGURE 4.9 ECONOMICS OF ACCELERATED PRODUCTION



SOURCE: ACIL ALLEN CONSULTING

An alternative way of looking at the question of 'acceleration economics' is to consider the sale of the target volume of gas to be supplied through the West–East Pipeline (about 175 PJ/a) over a 20-year period. If the producer was to sell that gas as LNG, at the same annual rate but starting in 20 years' time then (using the same assumptions as in the previous example) the net present value of those sales would be about A$4.16 billion. If on the other hand the producer was to sell the gas to the West–East Pipeline at the same rate and over the same period but with sales commencing ten years earlier, then it could achieve the same net present value outcome by selling the gas at an average unit price of A$5.65/GJ.

Taking the above considerations into account, we consider that it would be reasonable to assume a producer selling price, in current dollar terms, of between $5 and $6/GJ into pipe.

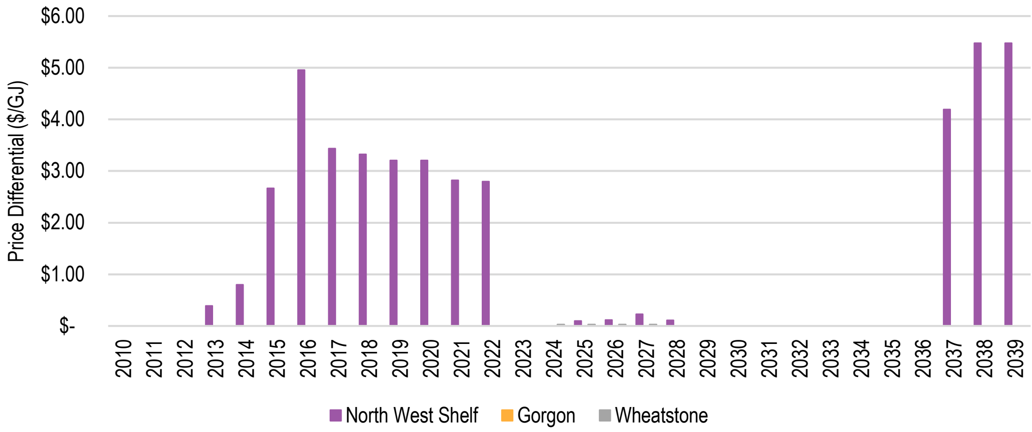
As the modelling results summarised in **Figure 4.8** show, at a gas price of $5 to $6/GJ into pipe, the West–East Pipeline under the Route1 alignment would not achieve the targeted levels of market penetration in Eastern Australia until somewhere between 2032 and 2034.

Impact on WA gas market

Because this case assumed no interaction with the Western Australian domestic gas market, the modelling did not reveal any impact on gas consumption or prices in Western Australia. However, to the extent that supply committed to the West–East Pipeline has the effect of reducing the reserves of gas available to supply Western Australian consumers, there is clearly potential for pricing and availability of gas to be affected. This was tested by reducing the reserves available to the domestic market in Western Australia by 4,000 PJ—approximately the amount of gas that would be supplied to Eastern Australian customers over a 20-year period at the target rate of delivery.

The results depended on where the reserves reductions were made (that is, which source of supply was assumed to provide the dedicated gas feed to the pipeline). Reducing reserves available to the Gorgon or Wheatstone projects by 4,000 PJ had little or no effect on modelled WA gas prices. However, reducing reserves in fields available to the North West Shelf project by 4,000 PJ had a significant effect on modelled WA gas prices in some, but not all years following the commissioning of the West–East Pipeline, as shown in **Figure 4.10**. The results suggest that whether or not dedication of gas reserves to the West–East Pipeline will have an effect on domestic gas prices in Western Australia will depend on where those reserves come from, and whether that reserves commitment results in a change to the marginal source of domestic supply.

FIGURE 4.10 EFFECTS ON WA DOMESTIC GAS PRICES OF DEDICATING RESERVES TO THE WEST–EAST PIPELINE

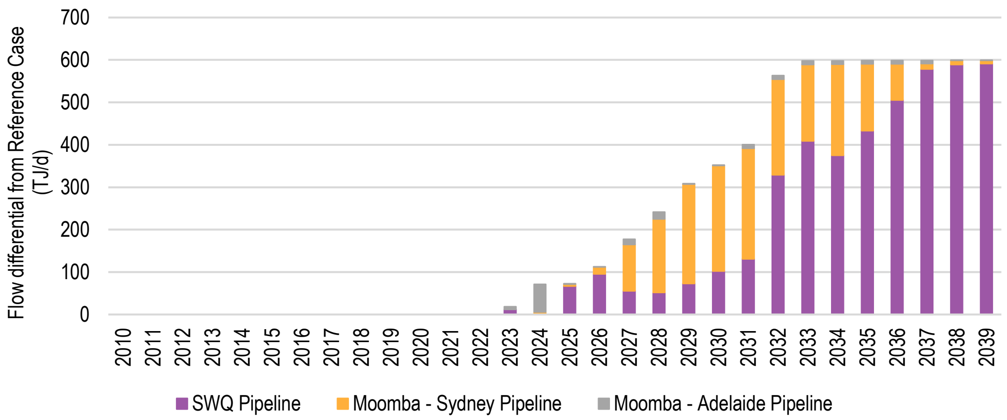


SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

Where is the supply taken up?

The question of where gas supplied by the West–East Pipeline is taken up in the market was examined by looking at differential flows on major pipelines downstream of Moomba under the '600 TJ/d, no WA domestic market connection' case. Modelled flows were assessed on the South West Queensland Pipeline (transporting gas to the east, towards Wallumbilla), the Moomba–Sydney Pipeline and the Moomba–Adelaide Pipeline. The results are shown in **Figure 4.11**.

FIGURE 4.11 WEST–EAST PIPELINE ROUTE 1, 600 TJ/D, NO WA DOMGAS LINK: DIFFERENTIAL FLOWS ON MAJOR TRANSMISSION PIPELINES IN EASTERN AUSTRALIA



SOURCE: ACIL ALLEN GASMARK MODELLING

Whereas initially much of the throughput on the West–East Pipeline is directed into the New South Wales market via the Moomba–Sydney Pipeline, the proportion of deliveries reporting to the South West Queensland Pipeline system increase over time. By the end of the modelling period, virtually all the gas carried on the West–East Pipeline is delivered into Queensland. Much of the gas supply is taken up in the Gladstone LNG plants, displacing high marginal cost CSG production. While this result begs the question whether it would be economically efficient to transport gas across the country to turn it into LNG when it could be converted to LNG in Western Australia, it is a rational outcome if the delivered cost of the Western Australian gas is lower than delivering high-cost marginal CSG production to the Gladstone facilities.

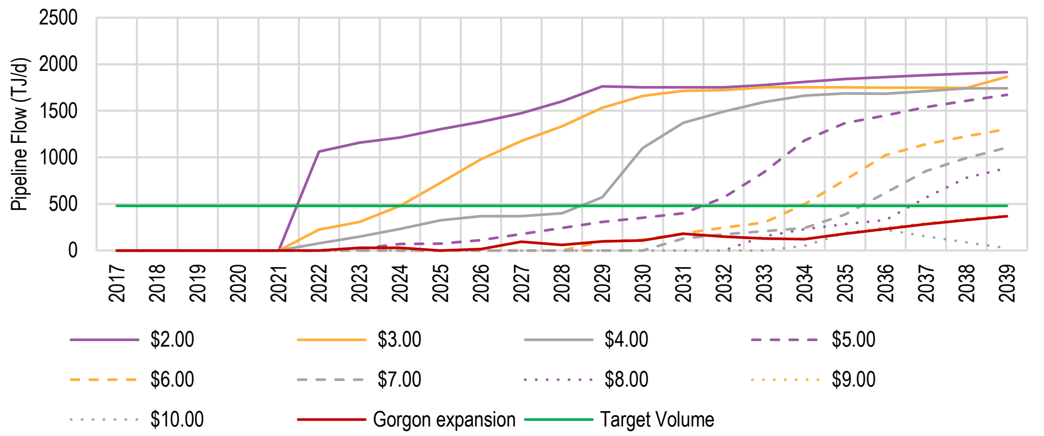
Even though much of the gas carried by the West–East Pipeline ends up in the Gladstone LNG plants, benefits are felt throughout the Eastern Australian domestic market in terms of lower wholesale gas prices. These price impacts are demonstrated in section 4.10.

4.4.4 Route 1 – Unconstrained case

A Route 1 case variant was run in which no capacity constraints were placed on the West–East Pipeline or on the gas field supplying it. The purpose of this variant was to assess the maximum level of Eastern Australian gas demand (domestic and LNG) that could be supplied by the West–East Pipeline under different gas price assumptions.

The results are summarised in **Figure 4.12**.

FIGURE 4.12 WEST–EAST PIPELINE ROUTE 1: MODELLED PIPELINE FLOWS AT DIFFERENT GAS COSTS. NO CAPACITY CONSTRAINTS, NO WA DOMESTIC MARKET CONNECTION



Note: Gas prices are expressed in real 2017 dollar terms

SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

The results show that, at low gas prices of $5/GJ or less, flows through the West–East Pipeline could potentially reach levels of more than 1,750 TJ/d—well above the targeted average throughput levels of 480 TJ/d and greater than the level of annual demand forecast for the Eastern Australian domestic market. This implies that a significant part of the gas delivered via the West–East Pipeline would be directed into LNG production at Gladstone.

4.4.5 Route 1 – sensitivity to LNG imports

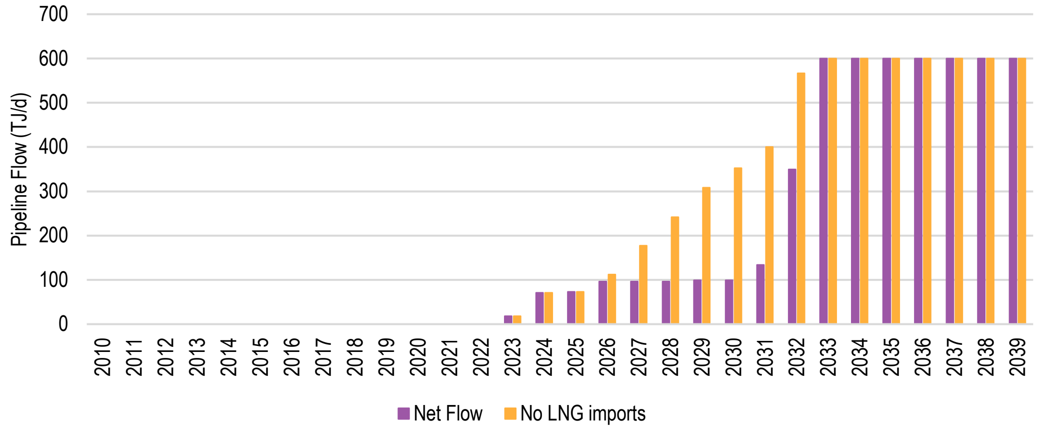
To test the sensitivity of modelled flows on the West–East Pipeline to the possible development of an LNG import terminal in Victoria (as proposed by AGL), a variant of the '600 TJ/d, no WA domgas' case was run in which an LNG import terminal is established at a site near Longford. It was assumed that the LNG terminal would have the capacity to supply up to 100 PJ/a[13] into the market from 2020, at a price of about $10/GJ (2017 real).

The resulting impact on gas flows on the West–East Pipeline is shown in **Figure 4.13** . While the LNG import terminal would suppress flows of the West–East Pipeline for some time, throughput on the pipeline eventually returns to the same levels as without the LNG terminal. This suggests that development of an LNG import terminal would not necessarily be fatal for the West–East Pipeline project. There could eventually be room in the market for both an LNG import terminal and the West–East Pipeline.

Of course, if the LNG terminal was expanded or duplicated, the impact on gas flows on the West–East Pipeline would be greater, further delaying the achievement of target levels of market penetration.

[13] The 100 PJ/a capacity assumption is based on a Floating Storage and Regasification Unit (FSRU) vessel with a capacity of 138,000 cubic meters, equivalent to about 3.5 PJ, capable of cycling (full to empty) approximately every 12 days.

FIGURE 4.13 WEST–EAST GAS PIPELINE, ROUTE 1: SENSITIVITY OF MODELLED FLOWS TO LNG IMPORTS



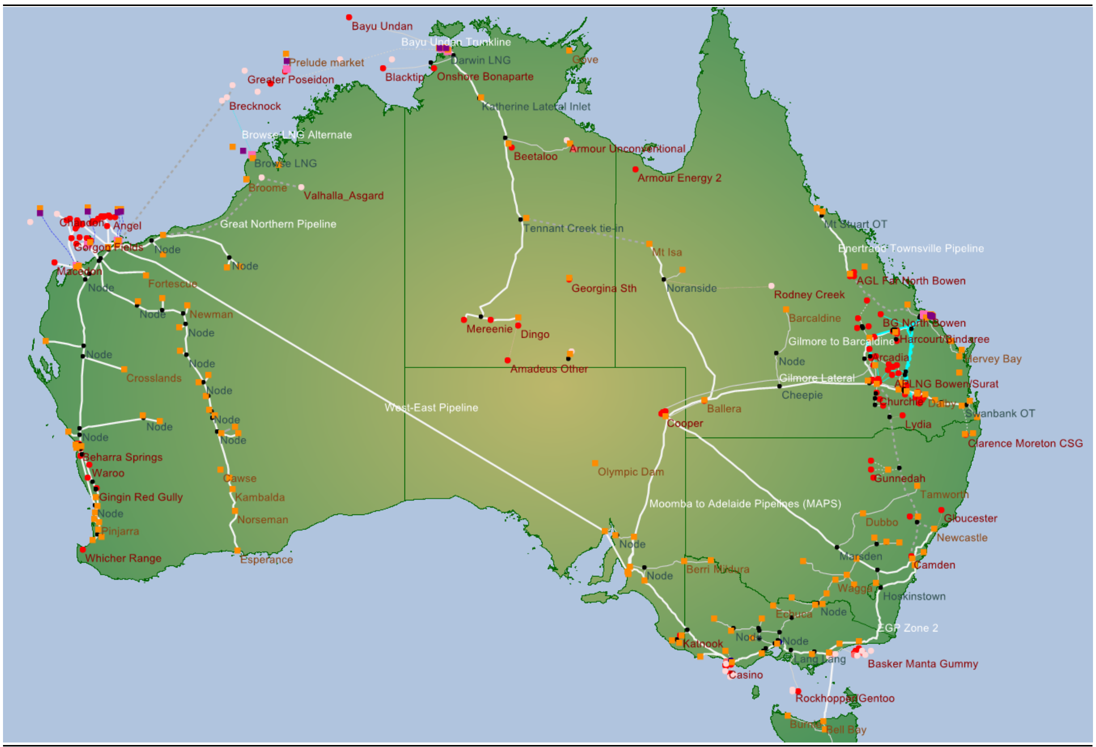
Note: Modelled pipeline flows assuming gas price into West–East Pipeline of $5/GJ (real 2017 dollars)

SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

4.5 Route 2—Dampier to Adelaide

Figure 4.14 shows the location of the West–East Pipeline Route 2 as represented within the *GasMark* model. The rationale for Route 2 was that flows on the pipeline might be improved by delivering gas directly to a significant market demand centre (Adelaide), from which point gas could then be carried via existing pipeline infrastructure to other major demand centres throughout south-eastern Australia.

FIGURE 4.14 ROUTE 2 LOCATION – MODEL INTERFACE



SOURCE: ACIL ALLEN CONSULTING GASMARK MODEL

4.5.1 Route 2 – Gorgon Expansion case

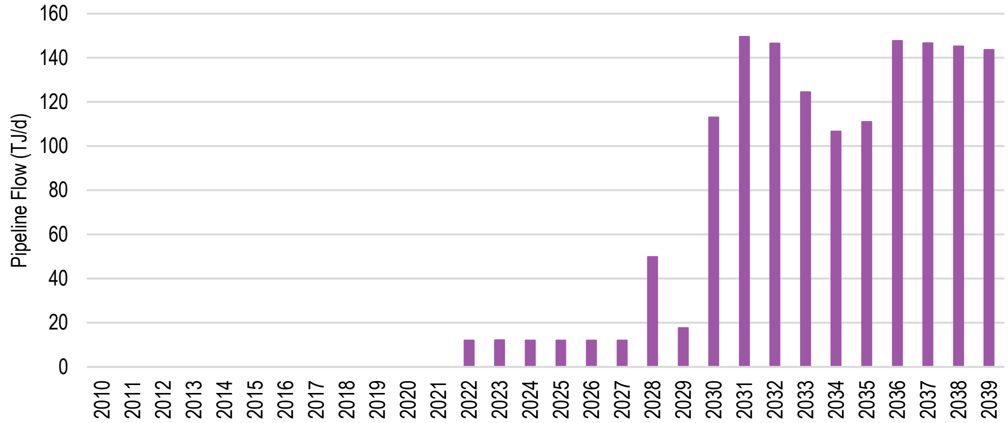
The first Route 2 case assumed that gas supply to support the West–East Pipeline would be by way of a 600 TJ/d expansion of the Gorgon domestic gas plant (to total 900 TJ/d). The choice of the Gorgon plant was made for ease of modelling: the incremental supply could equally well have been assumed to come from expansion of one or more of the other domestic gas production facilities in the region, including NWS domestic gas, Wheatstone domestic gas, Devil Creek and Varanus Island. No change was made to existing Gorgon domestic gas tie-in arrangements, with gas delivered into the Dampier–Bunbury Natural Gas Pipeline (DBNGP) at or near Compressor Station CS2.

The West–East Pipeline was assumed to be available, with capacity of up to 600 TJ/d, from 2022. The western end of the West–East Pipeline was assumed to tie into the Burrup Energy Pipeline east of Dampier. Gas supplied from Gorgon to the West–East Pipeline would therefore travel via part backhaul on DBNGP and the Burrup Energy Pipeline.

The additional gas supply from Gorgon was not isolated or quarantined from the WA domestic market. It was therefore able to seek market opportunities in Western Australia as well as Eastern Australia via the West–East Pipeline. The default Reference Case assumptions regarding the price at which Gorgon domestic gas is offered into the market were not changed. For this reason, the Gorgon Expansion case was not run across a range of prices.

The results are shown in **Figure 4.15**. There is little flow through the West–East Pipeline until 2030. Flows then increase to more than 100 TJ/d. However, net annual flow does not exceed 150 TJ/d average at any time through to the end of the modelling period. These results are inferior to those for Route 1.

FIGURE 4.15 WEST–EAST PIPELINE ROUTE 2: MODELLED FLOW UNDER THE GORGON EXPANSION CASE



SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

The modelling results demonstrate that a simple expansion of one or more of the Western Australian domestic gas plants to produce up to 600 TJ/d of additional gas to support the West–East Pipeline, but without any physical or contractual commitment of that gas supply to Eastern Australian supply, would see a large part of the incremental supply taken up in the Western Australian domestic market where it would displace more expensive gas supply alternatives. On this basis, the West–East Pipeline would not achieve the critical mass of market support required to make the pipeline viable.

Again the results suggest that, to achieve critical mass in terms of gas sales to the Eastern Australian market, incremental gas supply to support the West–East Pipeline will need to be physically or contractually dedicated to the project, effectively quarantining the project and its gas supply from the Western Australian domestic market.

4.5.2 Route 2 – 600 TJ/d capacity, with WA domgas case

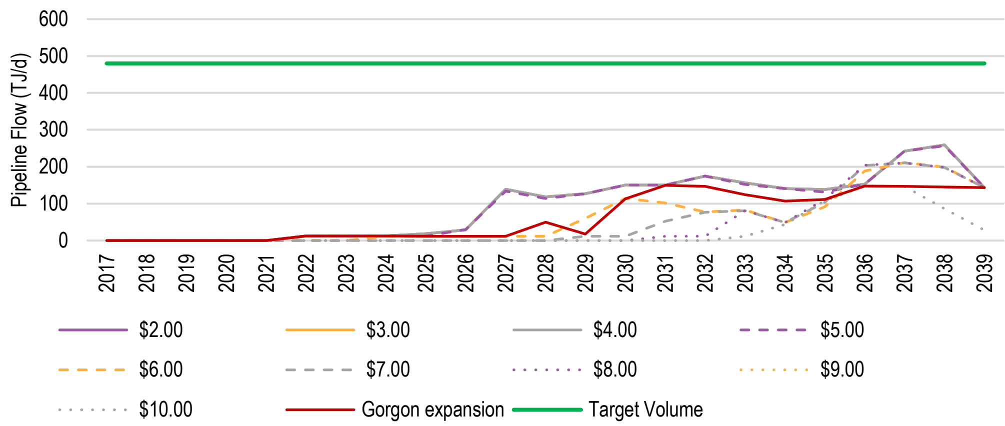
The next Route 2 case assumed that gas supply to support the West–East Pipeline would be provided by way of a dedicated gas production development, with a capacity of 600 TJ/d, that was also connected to and able to sell gas into the Western Australian domestic market via the Burrup Energy Pipeline/DBNGP system.

Based on a pipeline capital cost of $5.35 billion and compressor capital costs of $622 million, plus other assumptions as set out in **Table 4.1**, a West–East Pipeline tariff of $3.26/GJ (real, 2017-dollar terms) was estimated for firm capacity bookings of 480 TJ/d (80 per cent system average load factor).

This tariff was applied to the pipeline in the model, which was then run across a range of gas commodity prices from $2/GJ to $10/GJ at $1/GJ increments.

The results are summarised in **Figure 4.16**.

FIGURE 4.16 WEST–EAST PIPELINE ROUTE 2: MODELLED PIPELINE FLOWS AT DIFFERENT GAS COSTS. 600TJ/D, WITH WA DOMESTIC MARKET CONNECTION



Note: Gas prices are expressed in real 2017 dollar terms

SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

The green line represents an average daily flow of 480 TJ/d which is effectively full utilisation of the 600 TJ/d capacity pipeline at an assumed system average load factor of 80 per cent.

The red line provides a comparison with the results for the Gorgon expansion case. The Gorgon expansion results are consistent with the '600 TJ/d, with WA domgas' case at a gas cost of between $5 and $6/GJ.

The results show that, as for the 'Gorgon expansion' case, much of the gas produced from the dedicated gas production development would end up being sold in the Western Australian domestic market, and the West–East Pipeline would not achieve the target rate of throughput at any time during the modelling period, even at low gas prices. This reinforces the finding that, to achieve critical mass in terms of gas sales to the Eastern Australian market, gas supply to the pipeline will need to be physically or contractually quarantined from the Western Australian domestic market.

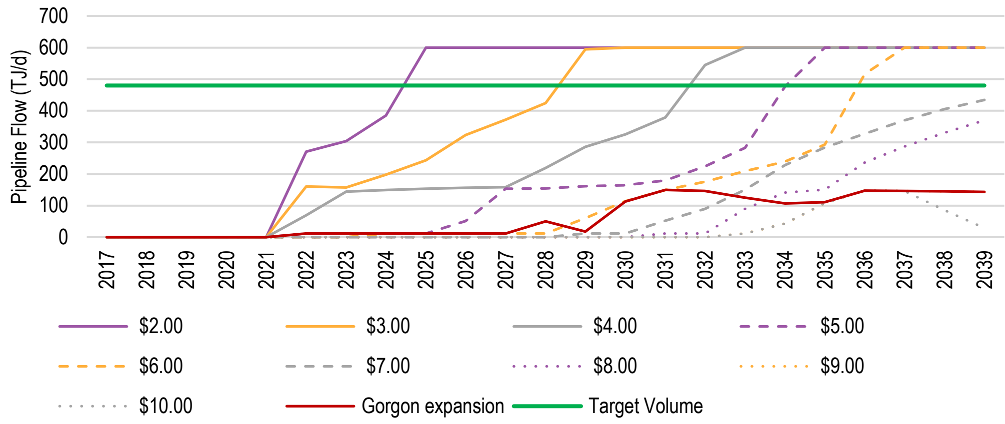
4.5.3 Route 2 – 600 TJ/d capacity, no WA domgas case

The next Route 2 case assumed that gas supply to support the West–East Pipeline would be by way of a dedicated production development with a capacity of 600 TJ/d. This was modelled as a separate gas production field located near the western end of the pipeline. No connection to the Burrup Energy Pipeline/DBNGP system was assumed, with the result that the new supply field was effectively quarantined from the Western Australian domestic market.

Other assumptions were the same as for the '600 TJ/d, with WA domgas' case.

The results are summarised in **Figure 4.17**.

FIGURE 4.17 WEST–EAST PIPELINE ROUTE 2: MODELLED PIPELINE FLOWS AT DIFFERENT GAS COSTS. 600TJ/D, NO WA DOMESTIC MARKET CONNECTION



Note: Gas prices are expressed in real 2017 dollar terms

SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

The green line on **Figure 4.17** represents an average daily flow of 480 TJ/d which is effectively full utilisation of the 600 TJ/d capacity pipeline at an assumed system average load factor of 80 per cent.

The results demonstrate that, by quarantining the gas supply to the West–East Pipeline from the Western Australian domestic market, it is possible to achieve the targeted level of market penetration across a range of gas costs. With gas supply at $2/GJ into the pipeline, all available gas is taken up with the 480 TJ/d average throughput being achieved in 2025.

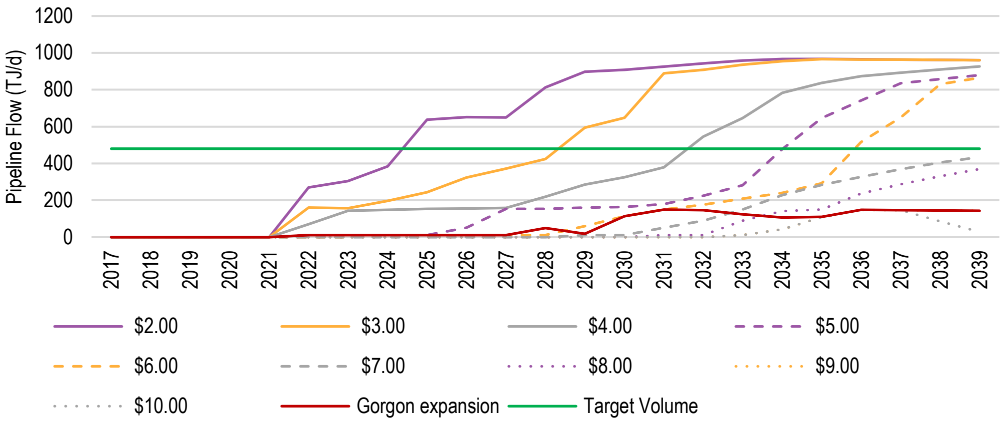
As the price of gas supply into the pipeline increases, the time taken to achieve targeted utilisation of the system also increases because the delivered price of gas at market locations in eastern Australia becomes progressively less competitive. At $3/GJ the 480 TJ/d utilisation target is reached in 2028; at $4/GJ in 2031; at $5/GJ in 2034; at $6/GJ in 2036; at $7/GJ or higher the utilisation target is not achieved before the end of the modelling period in 2039.

4.5.4 Route 2 – Unconstrained case

A Route 2 case variant was run in which no capacity constraints were placed on the West–East Pipeline or on the gas field supplying it. The purpose of this variant was to assess the maximum level of Eastern Australian gas demand (domestic and LNG) that could be supplied by the West–East Pipeline under different gas price assumptions.

The results are summarised in **Figure 4.18**.

FIGURE 4.18 WEST–EAST PIPELINE ROUTE 2: MODELLED PIPELINE FLOWS AT DIFFERENT GAS COSTS. NO CAPACITY CONSTRAINTS, NO WA DOMESTIC MARKET CONNECTION



Note: Gas prices are expressed in real 2017 dollar terms

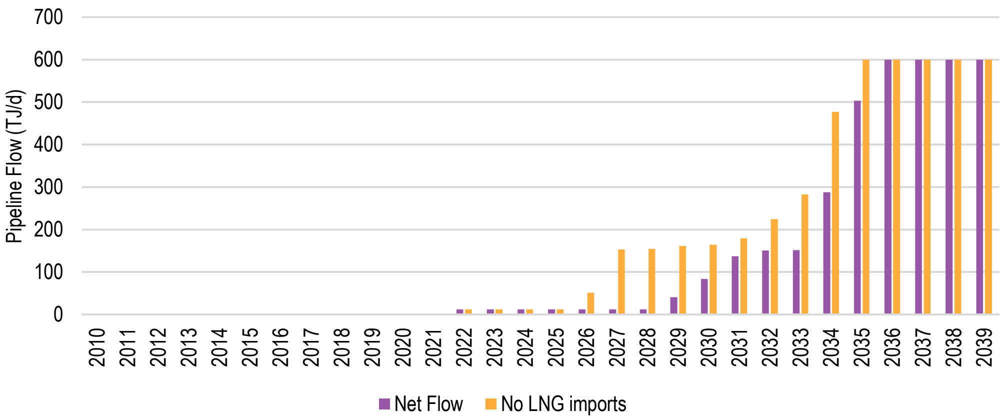
SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

The results show that, at gas prices of $6/GJ or less, flows through the West–East Pipeline to Adelaide could potentially reach levels of more than 900 TJ/d—well above the targeted average throughput levels of 480 TJ/d, but considerably less than the unconstrained market penetration under the Route 1 (Dampier – Moomba) assumptions.

4.5.5 Route 2 – sensitivity to LNG imports

To test the sensitivity of modelled flows on the West–East Pipeline (Route 2) to the possible development of an LNG import terminal in Victoria (as proposed by AGL), a variant of the '600 TJ/d, no WA domgas' case was run in which an LNG import terminal is established at a site near Longford. It was assumed that the LNG terminal would have the capacity to supply up to 100 PJ/a into the market from 2020, at a price of about $10/GJ (2017 real). The resulting impact on gas flows on the West–East Pipeline is shown in **Figure 4.19**.

FIGURE 4.19 WEST–EAST GAS PIPELINE, ROUTE 2: SENSITIVITY OF MODELLED FLOWS TO LNG IMPORTS



Note: Modelled pipeline flows assuming gas price into West–East Pipeline of $5/GJ (real 2017 dollars)

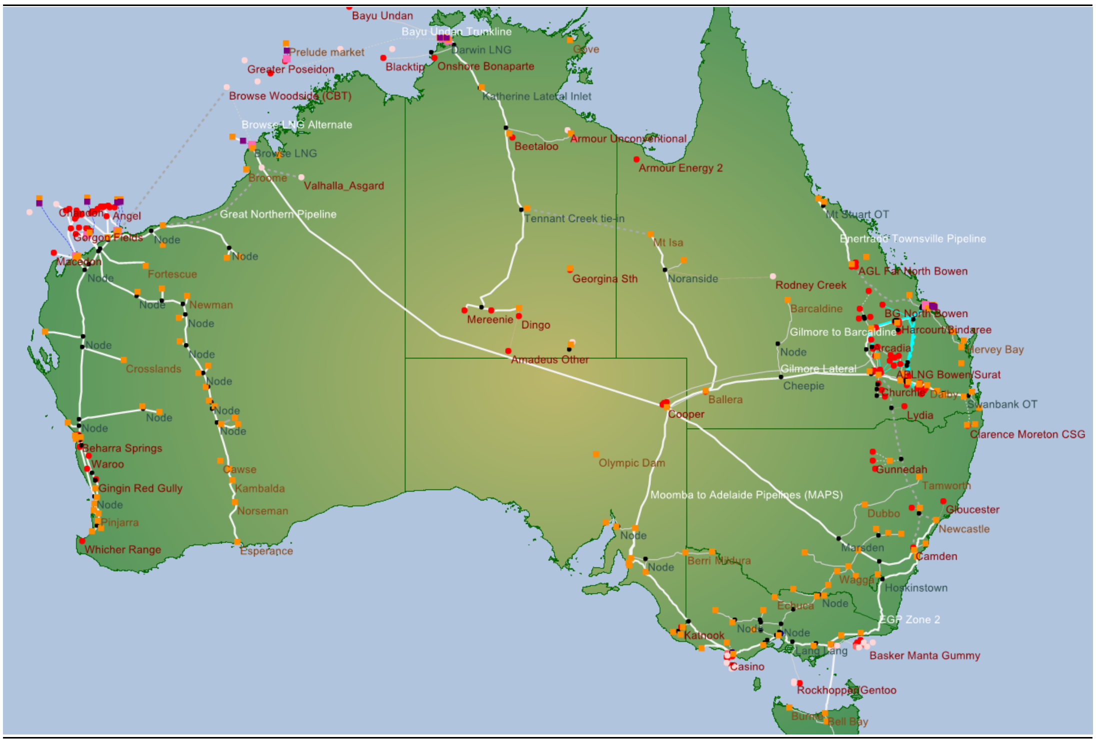
SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

While the LNG import terminal would suppress flows on the West–East Pipeline for some time, throughput on the pipeline eventually returns to the same levels as without the LNG terminal.

4.6 Route 3—Broome to Moomba

Figure 4.20 shows the location of the West–East Pipeline Route 3 as represented within the *GasMark* model.

FIGURE 4.20 ROUTE 3 LOCATION – MODEL INTERFACE



SOURCE: ACIL ALLEN CONSULTING GASMARK MODEL

For Route 3 the West–East Pipeline is assumed to originate at a location near Broome, connecting to a domestic gas plant associated with a new 10 million tonne per year LNG plant drawing gas from the Woodside Browse Basin (Calliance–Brecknock–Torosa fields). These fields collectively have resources totalling about 17,000 PJ. The production capacity of these fields is assumed to be around 2,050 TJ/d, sufficient to supply the LNG plant plus up to 600 TJ/d to the West–East Pipeline. Alternative sources of gas in the Browse Basin, such as Greater Poseidon, could support a similar development that would be equivalent from a high-level gas market modelling viewpoint. Route 3 is also assumed to tie in gas supply from a new development in the onshore Canning Basin (nominally Yulleroo) with production capacity of up to 150 TJ/d from 2022.

In making these gas supply assumptions, it is important to acknowledge that Woodside's current development plans for its Browse Basin gas reserves involve tying those reserves into the North West Shelf Project on the Burrup Peninsula. If this happens, the Browse Basin would essentially become an alternative source of gas supply that could support the West–East Pipeline Routes 1 and 2. The uncertainties regarding any future greenfield LNG or petrochemical development near Broome means that West–East Pipeline Routes 3 and 4 involve inherently higher risks than Routes 1 and 2.

The inclusion of a new LNG or petrochemical plant is a necessary assumption to justify bringing Browse Basin gas ashore near Broome. Without the economies of scale that such a facility would provide, the capital cost of developing gas production, transport and processing facilities to bring Browse Basin gas onshore would be difficult to justify. We consider it very unlikely that an offshore Browse Basin development could proceed solely based on gas supply into the West–East Pipeline.

There is no existing connection between the Browse of Canning Basins and the Western Australian domestic market. To test the effects of interaction between the West–East Pipeline (Routes 3 and 4) and the Western Australian domestic gas market, we have included a new pipeline connection from Yulleroo tying into the existing Pilbara Energy Pipeline (PEP)at Port Hedland. The capacity of this connection to deliver gas beyond Port Hedland would be effectively limited by the current capacity of the PEP which is 166 TJ/d.

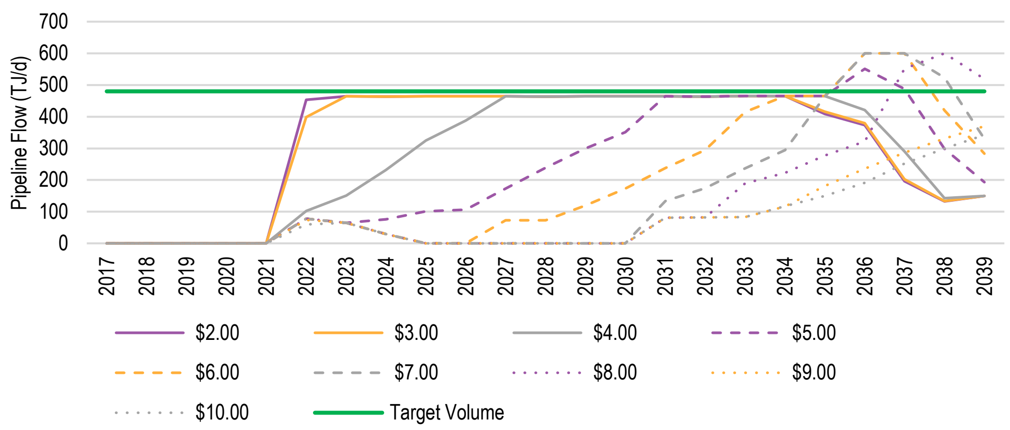
4.6.1 Route 3 – 600 TJ/d capacity, with WA domgas case

Based on a pipeline capital cost of $4.22 billion and compressor capital costs of $491 million, plus other assumptions as set out in **Table 4.1**, a West–East Pipeline tariff of $2.61/GJ (real, 2017-dollar terms) was estimated for firm capacity bookings of 480 TJ/d (80 per cent system average load factor).

This tariff was applied to the pipeline in the model, which was then run across a range of gas commodity prices from $2/GJ to $10/GJ at $1/GJ increments.

The results are summarised in **Figure 4.21**.

FIGURE 4.21 WEST–EAST PIPELINE ROUTE 3: MODELLED PIPELINE FLOWS AT DIFFERENT GAS COSTS. 600TJ/D, WITH WA DOMESTIC MARKET CONNECTION



Note: Gas prices are expressed in real 2017 dollar terms

SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

The green line represents an average daily flow of 480 TJ/d which is effectively full utilisation of the 600 TJ/d capacity pipeline at an assumed system average load factor of 80 per cent.

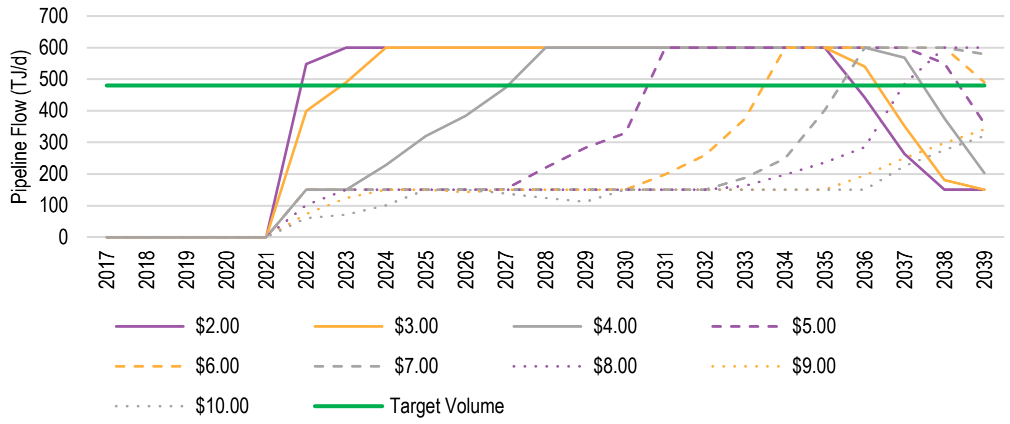
The results show that because of the capacity constraints on connections to the Western Australian domestic market—in particular, the 166 TJ/d capacity of the Pilbara Energy Pipeline)—domestic market connection does not reduce throughput on the West–East Pipeline to anywhere near the same extent as for Routes 1 and 2. Deliveries at or near the target volume levels are able to be achieved within the modelling period for all gas costs up to $8/GJ. However, it is apparent that throughput levels fall below target supply levels before the end of the modelling period, with the shortfalls commencing sooner at low gas prices. This reflects a key issue for the Browse Basin cases, namely the potential competition between the West–East Pipeline and the LNG plant as resource constraints become apparent. Even with a large resource endowment (17,000 PJ) the Woodside Browse fields, if produced at a rate equivalent to 13.65 mtpa of LNG (10 mtpa for the LNG plant and 3.65 mtpa for the pipeline), face deliverability issues within the modelling timeframe. The sooner the West–East Pipeline achieves target throughput volumes (2022 under the $2/GJ gas case), the sooner those constraints become apparent.

4.6.2 Route 3 – 600 TJ/d capacity, no WA domgas case

The next Route 3 case was modelled with the connection to the Western Australian domestic market disabled. All other assumptions were the same as for the '600 TJ/d, with WA domgas' case.

The results are summarised in **Figure 4.22**.

FIGURE 4.22 WEST–EAST PIPELINE ROUTE 3: MODELLED PIPELINE FLOWS AT DIFFERENT GAS COSTS. 600TJ/D, NO WA DOMESTIC MARKET CONNECTION



Note: Gas prices are expressed in real 2017 dollar terms

SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

The green line on **Figure 4.22** represents an average daily flow of 480 TJ/d which is effectively full utilisation of the 600 TJ/d capacity pipeline at an assumed system average load factor of 80 per cent.

The results demonstrate that, by quarantining the gas supply to the West–East Pipeline from the Western Australian domestic market, it is possible to achieve the targeted level of market penetration across a range of gas costs. With gas supply at $2/GJ into the pipeline, all available gas is taken up with the 480 TJ/d average throughput being achieved in 2022.

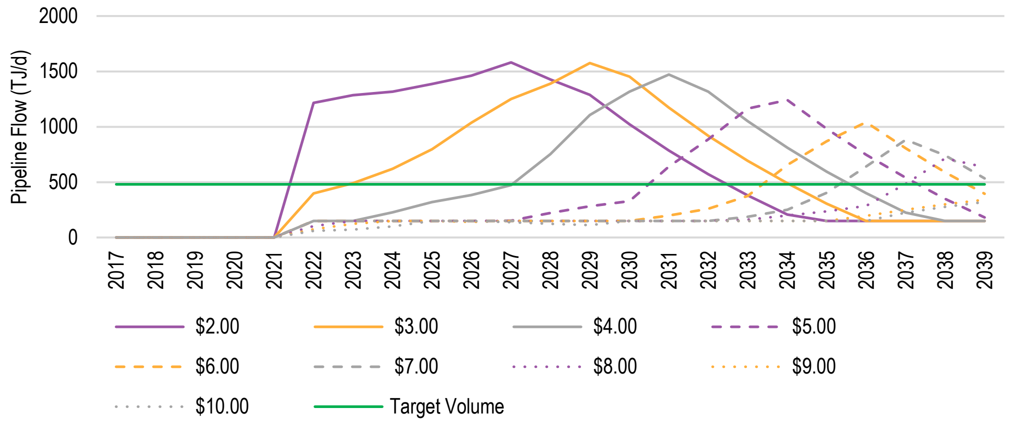
As the price of gas supply into the pipeline increases, the time taken to achieve targeted utilisation of the system also increases because the delivered price of gas at market locations in eastern Australia becomes progressively less competitive. At $3/GJ the 480 TJ/d utilisation target is reached in 2023; at $4/GJ in 2027; at $5/GJ in 2031; at $6/GJ in 2034; at $7/GJ in 2036; at $8/GJ in 2038. At $9/GJ and above the utilisation target is not achieved before the end of the modelling period in 2039.

4.6.3 Route 3 – Unconstrained case

A Route 3 case variant was run in which no capacity constraints were placed on the West–East Pipeline or on the gas field supplying it. The purpose of this variant was to assess the maximum level of Eastern Australian gas demand (domestic and LNG) that could be supplied by the West–East Pipeline under different gas price assumptions.

The results, summarised in **Figure 4.23**, show that at gas prices of $6/GJ or less, flows through the West–East Pipeline via Route 3 could potentially reach levels of more than 1,000 TJ/d—well above the targeted average throughput levels of 480 TJ/d. However, these rates are not sustainable as the limitations of the developed Browse Basin reserves—when also supplying a 10 mtpa LNG plant—become very apparent.

FIGURE 4.23 WEST–EAST PIPELINE ROUTE 3: MODELLED PIPELINE FLOWS AT DIFFERENT GAS COSTS. NO CAPACITY CONSTRAINTS, NO WA DOMESTIC MARKET CONNECTION



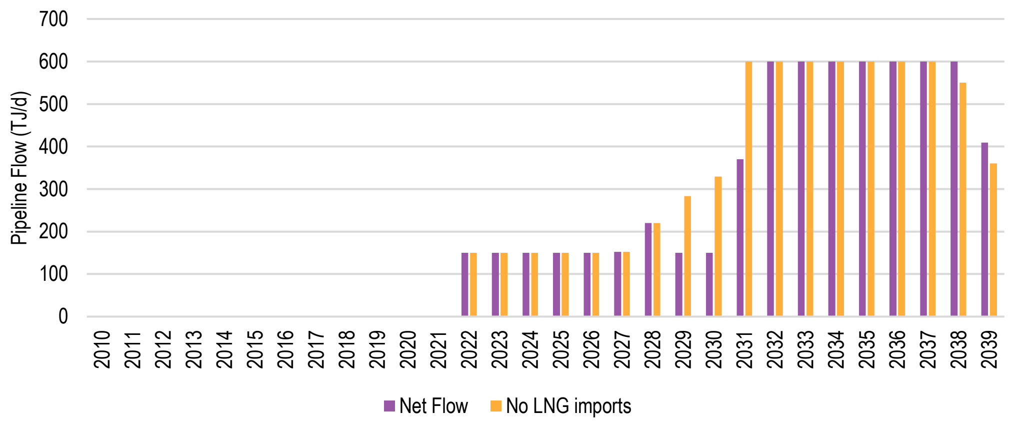
Note: Gas prices are expressed in real 2017 dollar terms

SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

4.6.4 Route 3 – sensitivity to LNG imports

To test the sensitivity of modelled flows on the West–East Pipeline (Route 3) to the possible development of an LNG import terminal in Victoria (as proposed by AGL), a variant of the '600 TJ/d, no WA domgas' case was run in which an LNG import terminal is established at a site near Longford. It was assumed that the LNG terminal would have the capacity to supply up to 100 PJ/a into the market from 2020, at a price of about $10/GJ (2017 real). The resulting impact on gas flows on the West–East Pipeline is shown in **Figure 4.24**.

FIGURE 4.24 WEST–EAST GAS PIPELINE, ROUTE 3: SENSITIVITY OF MODELLED FLOWS TO LNG IMPORTS



Note: Modelled pipeline flows assuming gas price into West–East Pipeline of $5/GJ (real 2017 dollars)

SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

While the LNG import terminal would suppress flows on the West–East Pipeline for some time, throughput on the pipeline eventually returns to the same levels as without the LNG terminal.

4.7 Route 4—Broome to Adelaide

Figure 4.25 shows the location of the West–East Pipeline Route 4 as represented within the *GasMark* model.

FIGURE 4.25 ROUTE 4 LOCATION – MODEL INTERFACE

SOURCE: ACIL ALLEN CONSULTING GASMARK MODEL

The rationale for the selection of Adelaide as the terminus for the pipeline under this route alternative was that flows on the pipeline might be improved by delivering gas directly to a significant market demand centre (Adelaide), from which point gas could then be carried via existing pipeline infrastructure to other major demand centres throughout south-eastern Australia.

For Route 4 the assumptions regarding gas supply into the pipeline are the same as for Route 3.

Again, the inclusion of a new LNG or petrochemical plant is a necessary assumption to justify bringing Browse Basin gas ashore near Broome.

To test the effects of interaction between the West–East Pipeline (Routes 3 and 4) and the Western Australian domestic gas market, we have included a new pipeline connection from Yulleroo tying into the existing Pilbara Energy Pipeline (PEP)at Port Hedland. The capacity of this connection to deliver gas beyond Port Hedland would be effectively limited by the current capacity of the PEP which is 166 TJ/d.

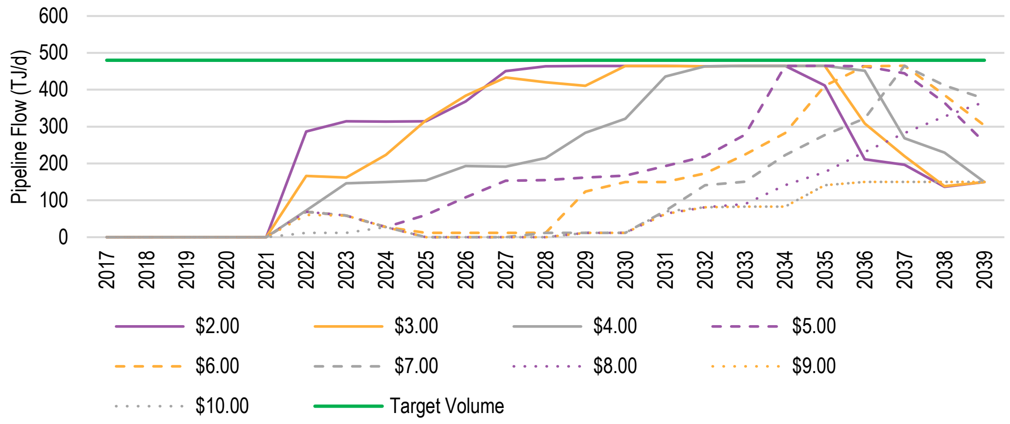
4.7.1 Route 4 – 600 TJ/d capacity, with WA domgas case

Based on a pipeline capital cost of $4.93 billion and compressor capital costs of $573 million, plus other assumptions as set out in **Table 4.1**, a West–East Pipeline tariff of $3.02/GJ (real, 2017-dollar terms) was estimated for firm capacity bookings of 480 TJ/d (80 per cent system average load factor).

This tariff was applied to the pipeline in the model, which was then run across a range of gas commodity prices from $2/GJ to $10/GJ at $1/GJ increments.

The results are summarised in **Figure 4.26**.

FIGURE 4.26 WEST–EAST PIPELINE ROUTE 4: MODELLED PIPELINE FLOWS AT DIFFERENT GAS COSTS. 600TJ/D, WITH WA DOMESTIC MARKET CONNECTION



Note: Gas prices are expressed in real 2017 dollar terms

SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

The green line represents an average daily flow of 480 TJ/d which is effectively full utilisation of the 600 TJ/d capacity pipeline at an assumed system average load factor of 80 per cent.

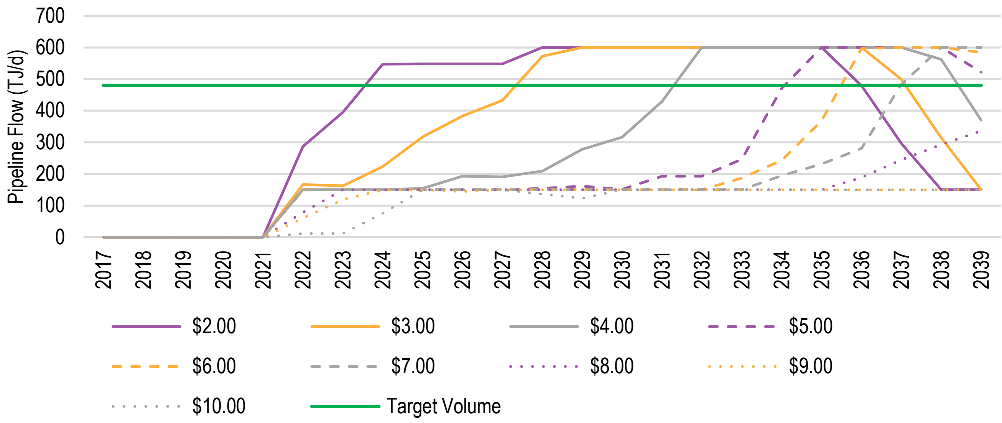
The results show that because of the capacity constraints on connections to the Western Australian domestic market—in particular, the 166 TJ/d capacity of the Pilbara Energy Pipeline)—domestic market connection does not reduce throughput on the West–East Pipeline to anywhere near the same extent as for Routes 1 and 2. Deliveries at or near the target volume levels are able to be achieved within the modelling period for all gas costs up to $7/GJ. However, it is apparent that throughput levels fall below target supply levels before the end of the modelling period, with the shortfalls commencing sooner at low gas prices. This reflects a key issue for the Browse Basin cases, namely the potential competition between the West–East Pipeline and the LNG plant as resource constraints become apparent. Even with a large resource endowment (17,000 PJ) the Woodside Browse fields, if produced at a rate equivalent to 13.65 mtpa of LNG (10 mtpa for the LNG plant and 3.65 mtpa for the pipeline), face deliverability issues within the modelling timeframe. The more quickly throughput levels on the West–East Pipeline ramp up, the sooner those constraints become apparent.

4.7.2 Route 4 – 600 TJ/d capacity, no WA domgas case

The next Route 4 case was modelled with the connection to the Western Australian domestic market disabled. All other assumptions were the same as for the ‘600 TJ/d, with WA domgas’ case.

The results are summarised in **Figure 4.27**.

FIGURE 4.27 WEST–EAST PIPELINE ROUTE 4: MODELLED PIPELINE FLOWS AT DIFFERENT GAS COSTS. 600TJ/D, NO WA DOMESTIC MARKET CONNECTION



Note: Gas prices are expressed in real 2017 dollar terms

SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

The green line represents an average daily flow of 480 TJ/d which is effectively full utilisation of the 600 TJ/d capacity pipeline at an assumed system average load factor of 80 per cent.

The results demonstrate that, by quarantining the gas supply to the West–East Pipeline from the Western Australian domestic market, it is possible to achieve the targeted level of market penetration across a range of gas costs. With gas supply at $2/GJ into the pipeline, all available gas is taken up with the 480 TJ/d average throughput being achieved in 2024.

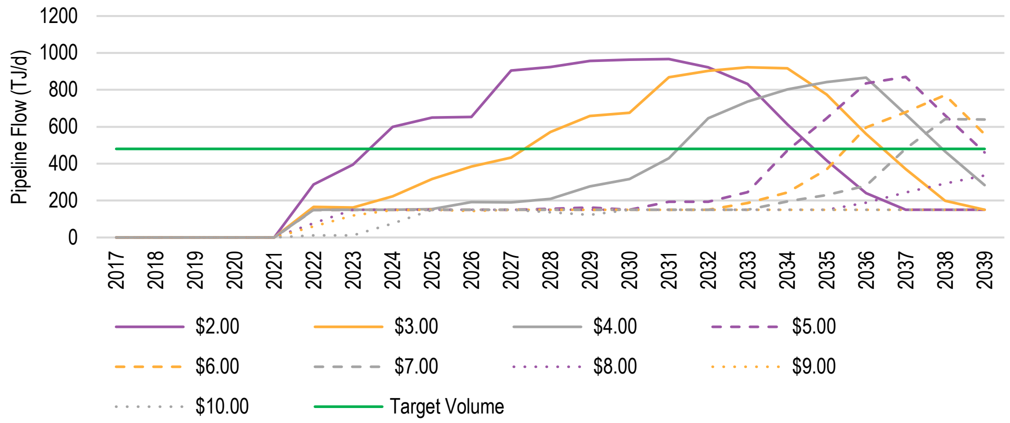
As the price of gas supply into the pipeline increases, the time taken to achieve targeted utilisation of the system also increases because the delivered price of gas at market locations in eastern Australia becomes progressively less competitive. At $3/GJ the 480 TJ/d utilisation target is reached in 2028; at $4/GJ in 2032; at $5/GJ in 2034; at $6/GJ in 2036; at $7/GJ in 2037. At $8/GJ and above the utilisation target is not achieved before the end of the modelling period in 2039.

4.7.3 Route 4 – Unconstrained case

A Route 4 case variant was run in which no capacity constraints were placed on the West–East Pipeline or on the gas field supplying it. The purpose of this variant was to assess the maximum level of Eastern Australian gas demand (domestic and LNG) that could be supplied by the West–East Pipeline under different gas price assumptions.

The results, summarised in **Figure 4.28**, show that at gas prices of $5/GJ or less, flows through the West–East Pipeline via Route 4 could potentially reach levels of more than 800 TJ/d—well above the targeted average throughput levels of 480 TJ/d. However, these rates are not sustainable as the limitations of the developed Browse Basin reserves—when also supplying a 10 mtpa LNG plant—become very apparent.

FIGURE 4.28 WEST–EAST PIPELINE ROUTE 4: MODELLED PIPELINE FLOWS AT DIFFERENT GAS COSTS. NO CAPACITY CONSTRAINTS, NO WA DOMESTIC MARKET CONNECTION



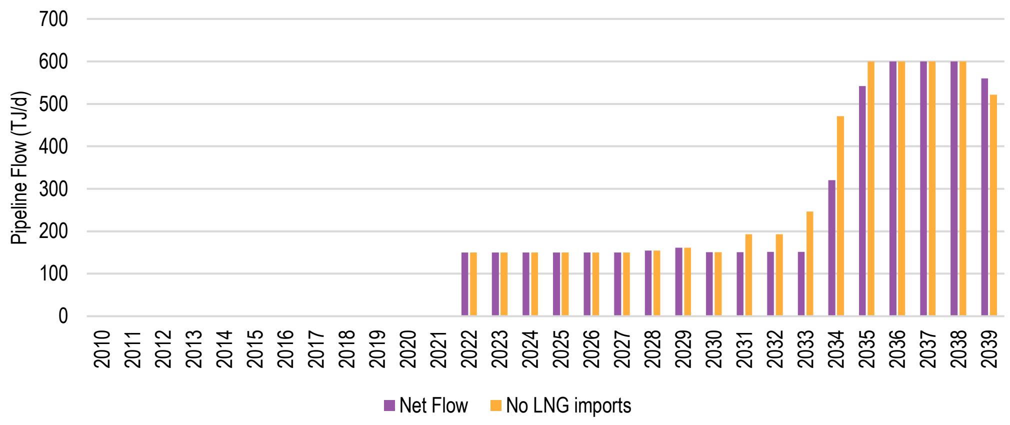
Note: Gas prices are expressed in real 2017 dollar terms

SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

4.7.4 Route 4 – sensitivity to LNG imports

To test the sensitivity of modelled flows on the West–East Pipeline (Route 4) to the possible development of an LNG import terminal in Victoria (as proposed by AGL), a variant of the '600 TJ/d, no WA domgas' case was run in which an LNG import terminal is established at a site near Longford. It was assumed that the LNG terminal would have the capacity to supply up to 100 PJ/a into the market from 2020, at a price of about $10/GJ (2017 real). The resulting impact on gas flows on the West–East Pipeline is shown in **Figure 4.29**.

FIGURE 4.29 WEST–EAST GAS PIPELINE, ROUTE 4: SENSITIVITY OF MODELLED FLOWS TO LNG IMPORTS



Note: Modelled pipeline flows assuming gas price into West–East Pipeline of $5/GJ (real 2017 dollars)

SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

While the LNG import terminal would suppress flows on the West–East Pipeline for some time, throughput on the pipeline eventually returns to the same levels as without the LNG terminal.

4.8 Other pipeline route alternatives

Two other pipeline route alternatives were also tested, but were not modelled in depth:

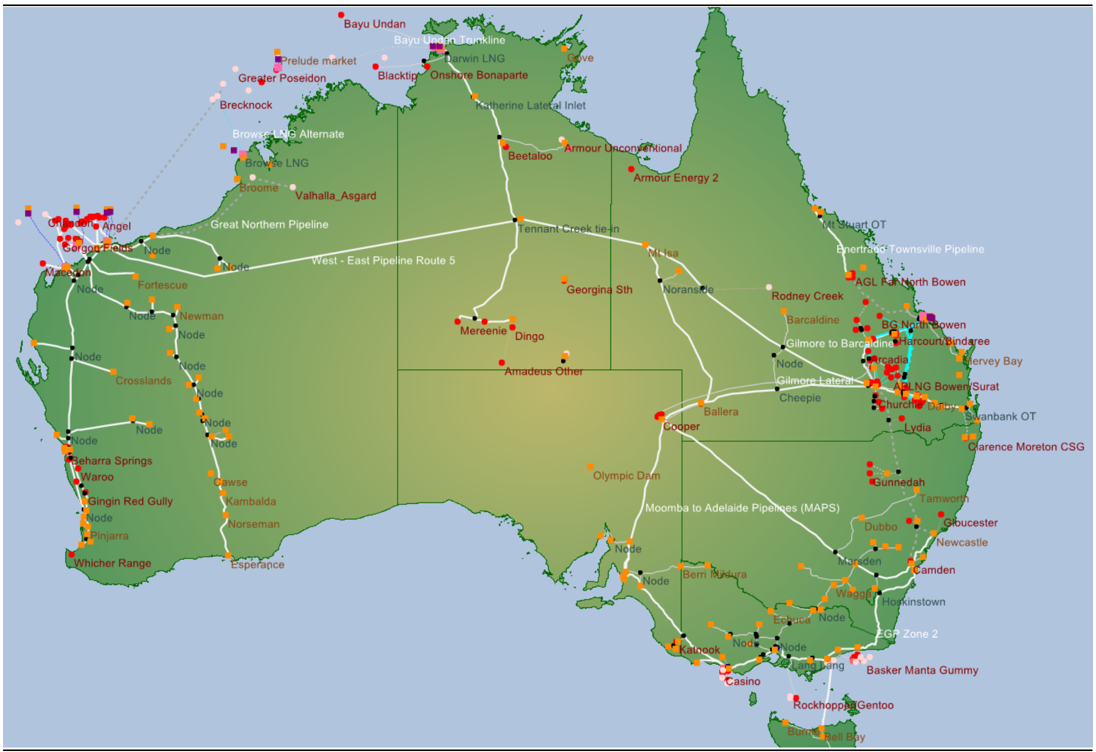
— A **Northern Route** in which the West–East Pipeline is built from Dampier to Tennant Creek, linking up with the Northern Gas Pipeline.

— A **'Moomba via Amadeus'** route in which the West–East Pipeline is built from Dampier to the Amadeus Basin in the Northern Territory, linking up with a Southern NT Pipeline (SNP) linking the Amadeus Basin to Moomba.

4.8.1 Northern Route Alternative

The location of the Northern Route Alternative as represented in the *GasMark* model is shown in **Figure 4.30**. The route was tested because it could potentially provide a more direct route to the Gladstone LNG facilities, with enhanced supply into Gladstone relieving pressure on other sources of supply in Eastern Australia thereby providing system-wide benefits in terms of improved supply and lower prices.

FIGURE 4.30 NORTHERN ROUTE ALTERNATIVE



SOURCE: ACIL ALLEN CONSULTING

This route assumed:

— A West–East Pipeline connection of approximately 1,900 km, from Dampier to Tennant Creek. Capital cost estimates pro-rated from GHD estimates for Route 1, using the same cost benchmarks, giving a pipeline capital cost of $3.46 billion and compression capital cost of $400 million. On this basis, a West–East Pipeline tariff of $2.17/GJ (real, 2017-dollar terms) was estimated for firm capacity bookings of 480 TJ/d (80 per cent system average load factor).

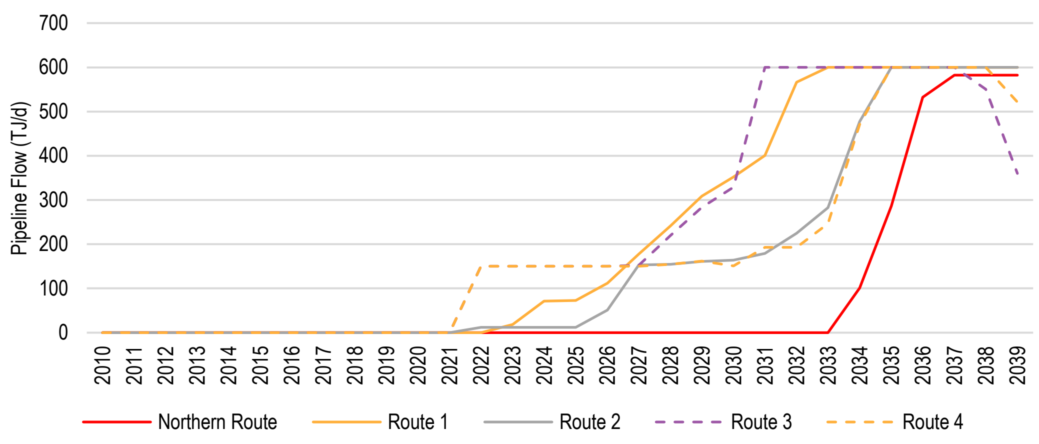
— Expansion of the Northern Gas Pipeline (Tennant Creek to Mount Isa) up to 600 TJ/d. Tariff was assumed to be achieved without changed to the existing NGP tariffs.

— A new Mount Isa –Wallumbilla pipeline, approximately 1,240 km, capacity 600 TJ/d. Capital cost estimate of about $2 billion and compression capital cost of $260 million giving a tariff of $1.38/GJ (real, 2017-dollar terms) based on firm capacity bookings of 480 TJ/d (80 per cent system average load factor).

The resulting annual pipeline flows through the West–East Pipeline, assuming $5/GJ gas feed into pipe, are shown in **Figure 4.31**. Compared to the corresponding modelled flows for Routes 1 to 4, the

Northern Route sees a significant delay in market penetration. No flows are recorded prior to 2034, and full utilisation of available capacity does not occur until 2037.

FIGURE 4.31 COMPARISON OF ANNUAL PIPELINE THROUGHPUT FOR NORTHERN ROUTE WITH ROUTES 1 – 4



Note: Results are for gas priced at $5/GJ (2017 real) into pipeline; no interconnection to WA domestic market

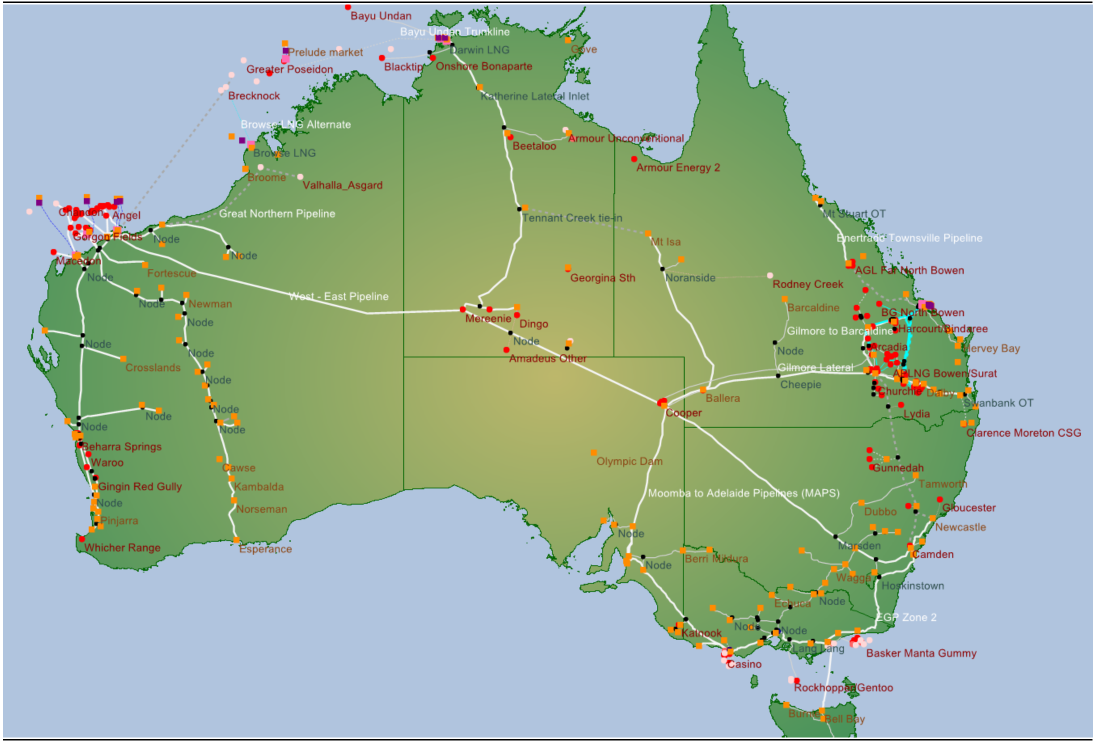
SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

Given the inferior modelled utilisation of the Northern Route, no further modelling of this option was undertaken.

4.8.2 Moomba via Amadeus Route Alternative

The final route option tested (**Figure 4.32**) was a case in which the West–East Pipeline is built from Dampier to the Amadeus Basin in the Northern Territory where it joins a Southern NT Pipeline (SNP).

FIGURE 4.32 MOOMBA VIA AMADEUS ROUTE ALTERNATIVE



SOURCE: ACIL ALLEN CONSULTING

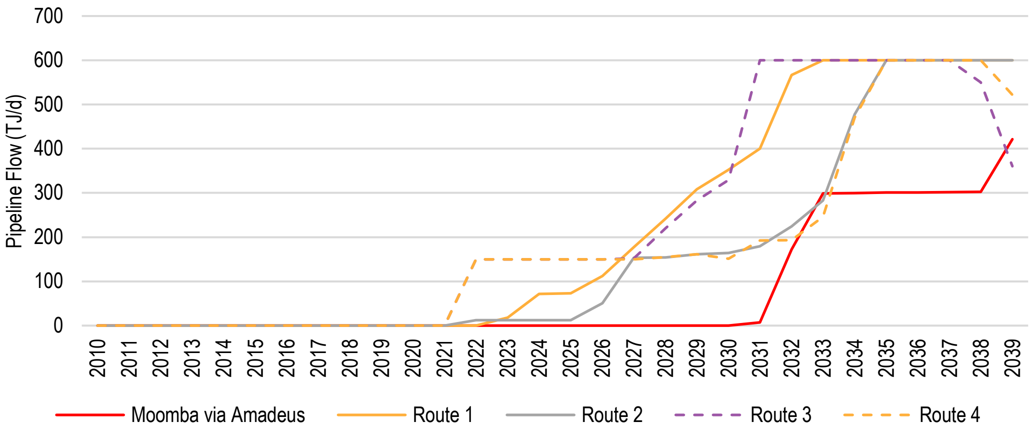
This case assumes that the SNP from Amadeus Basin to Moomba is supported by Northern Territory gas production from the Beetaloo and Amadeus Basins ramping up to 350 TJ/d over ten years from 2020.

The West–East Pipeline component of this delivery system is about 1,640 km long, with a pipeline capital cost of about $3 billion and compressor capital costs of about $350 million, resulting in a tariff of $1.89/GJ (real, 2017-dollar terms) based on firm capacity bookings of 480 TJ/d (80 per cent system average load factor).

The SNP component of the delivery system is about 1,000 km long, with a pipeline capital cost of about $1.8 billion and compressor capital costs of about $215 million, resulting in a tariff of $1.23/GJ (real, 2017-dollar terms) based on firm capacity bookings of 480 TJ/d (80 per cent system average load factor).

The resulting flows through the West–East Pipeline component of this system are shown in **Figure 4.33**. Flow is restricted to about 300 TJ/d with Northern Territory supply replacing around half the Western Australian supply seen in other route options. The lower flows on the West–East Pipeline would push breakeven tariffs to unsustainable levels, making the pipeline non-viable.

FIGURE 4.33 COMPARISON OF ANNUAL PIPELINE THROUGHPUT FOR MOOMBA VIA AMADEUS ROUTE WITH ROUTES 1 – 4



Note: Results are for gas priced at $5/GJ (2017 real) into pipeline; no interconnection to WA domestic market

SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

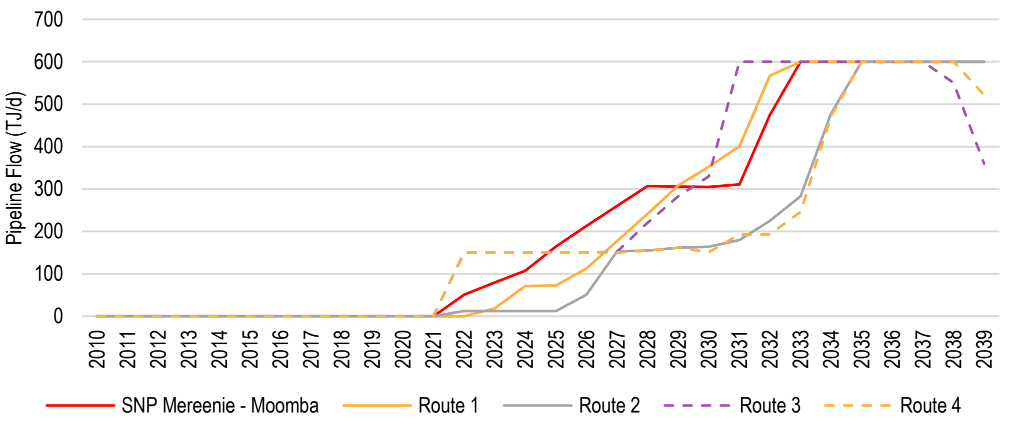
As shown in **Figure 4.34**, the SNP achieves a similar ramp-up profile to West–East Pipeline Routes 1 and 3, reaching 600 TJ/d by 2032, with supply coming in roughly equal parts from Western Australia and the Northern Territory.

This highlights the risk to the West–East Pipeline posed by the possible emergence of more proximate gas supply in the Northern Territory or elsewhere.

The conclusion from this analysis is that the West–East Pipeline and SNP are likely to be mutually exclusive options, not complementary projects.

Given the inferior modelled utilisation of the West–East Pipeline component of the Moomba via Amadeus Route, no further modelling of this option was undertaken.

FIGURE 4.34 COMPARISON OF ANNUAL PIPELINE THROUGHPUT FOR SOUTHERN NORTHERN TERRITORY PIPELINE (MEREENIE TO MOOMBA) WITH ROUTES 1 – 4



Note: Results are for gas priced at $5/GJ (2017 real) into pipeline; no interconnection to WA domestic market

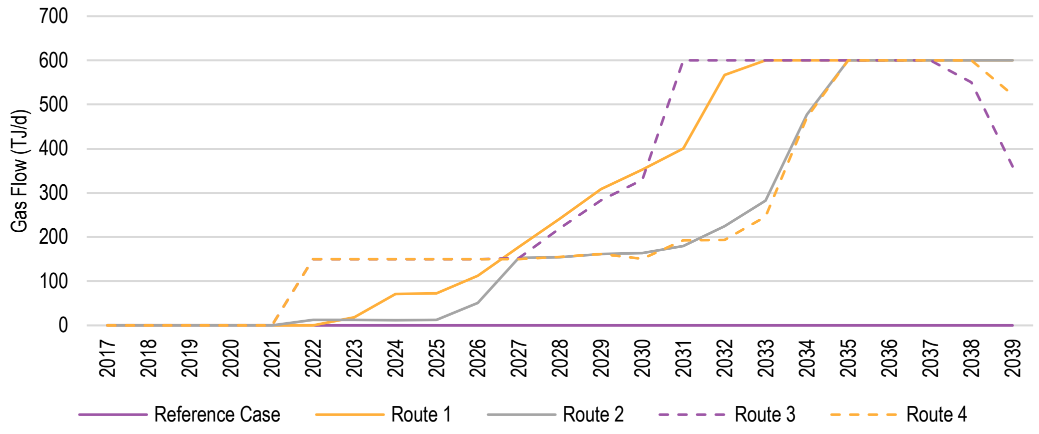
SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

4.9 Comparison of route alternatives

Figure 4.35 compares the modelled annual flows on the West–East Pipeline for Routes 1 to 4.

The routes terminating at Adelaide (Routes 2 and 4) show long plateaus at around 150 TJ/d indicating that they take up the available market in South Australia but do not begin to make significant inroads in markets beyond South Australia until after 2030. The routes terminating at Moomba (Routes 1 and 3) achieve high rates of throughput around 4 to 5 years earlier than the routes to Adelaide. This reflects the fact that delivery at Moomba allows more efficient access to markets throughout Eastern Australia, and in particular to the Gladstone LNG plants which, as discussed in section 4.4.3, take most of the gas delivered by the West–East Pipeline in the long term.

FIGURE 4.35 COMPARISON OF MODELLED NET FLOW THROUGH WEST–EAST PIPELINE, ROUTES 1 TO 4



Note: Throughput profiles for Routes 1 – 4 are for gas delivered into West–East Pipeline at $5/GJ (real 2017)

SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

Based on this comparison of modelled annual pipeline flows, the routes terminating at Moomba (Routes 1 and 3) are clearly the preferred routes because they achieve target rates of market penetration more quickly than the Adelaide-terminating routes.

Route 3 (ex Broome) achieves the fastest overall ramp-up and, if this were the only consideration, would be identified as the preferred route. However, there are other significant considerations. First and most importantly, there is currently no commercial gas production that comes on shore near Broome. The nearest onshore gas production facility is located at Dampier.

Inevitably, therefore, a pre-condition to progressing the West–East Pipeline via Route 3 would be a commitment to construct a new greenfield gas production facility. As discussed in section 4.6, the establishment of any onshore gas production facility near Broome, based on Browse Basin gas, would be likely to rely on a new LNG or petrochemical plant that would provide the economies of scale required to justify the very large capital cost of developing gas production, transport and processing facilities to bring Browse Basin gas onshore. We consider it very unlikely that and offshore Browse Basin development could proceed based solely on gas supply into the West–East Pipeline.

Any decision to construct the West–East Pipeline from a start point located near Broome would therefore be likely to rely on a concurrent decision to build a major LNG or petrochemical plant. Gas feed into the pipeline would effectively be provided as a ‘side stream’ of production from the LNG or petrochemical plant, which would be the larger capital investment and the key decision driver. Effectively, the timing of any decision to progress the West–East Pipeline would be dictated by decisions around the timing of the associated LNG or petrochemical plant, which would have to be built in an area of know environmental and cultural heritage sensitivity. This creates very significant co-ordination and alignment risks in relation to Browse/Canning Basin gas supply and leads us to identify Pipeline Route 1 (Dampier – Moomba) as the currently preferred route alignment.

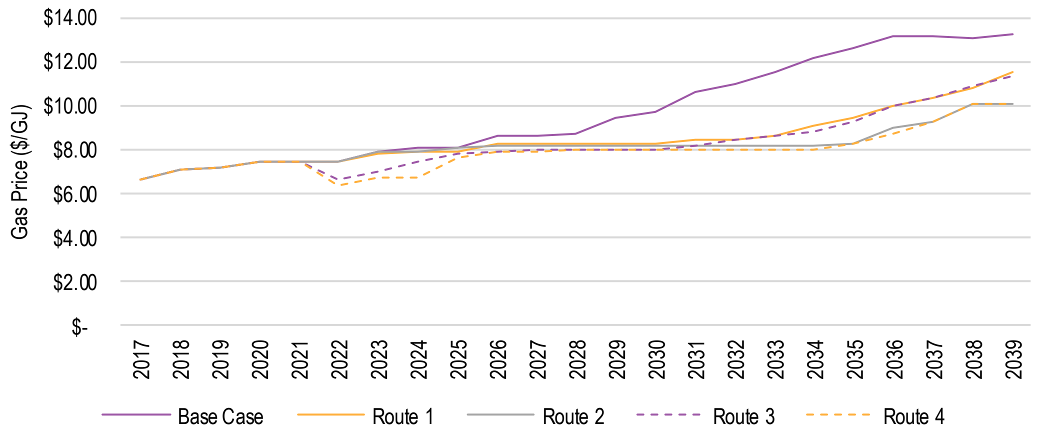
4.10 Modelled gas prices

This section provides information on the modelled effects of West–East Pipeline interconnection on wholesale gas prices at major domestic market centres in Australia. The prices shown are market clearing prices, including gas transmission costs but no distribution or retail charges. Prices are determined by an algorithm that assumes economically rational and efficient market settlement, with supply and demand matched on a least-cost basis. The model is not forward looking: it seeks to achieve an efficient market clearance for each settlement period but does not maximise production value or minimise supply cost on an inter-temporal basis. It does not take account of commercial behaviours of buyers and sellers in response to anticipated market trends, nor does it capture the premium which buyers may pay for volume flexibility terms in gas supply contracts. In this sense the modelled results are more like average spot market prices than term contract prices.

4.10.1 Adelaide

Figure 4.36 compares the modelled gas prices at Adelaide under Routes 1 to 4 with the Reference Case prices. Under the Reference Case, prices rise in real terms to a plateau level of around $13/GJ which represents the transport-adjusted cost of diverting LNG away from the Gladstone plants. All four West–East Pipeline routes deliver significant price reductions which tend to increase over time to as much as $4/GJ. In the long run, the Adelaide-terminating options (Routes 2 and 4) deliver lower prices which is in line with expectations, given that these routes supply gas to the Adelaide market by the most direct route, minimising costs of transport.

FIGURE 4.36 COMPARISON OF MODELLED GAS PRICES AT ADELAIDE, ROUTES 1 TO 4 AND REFERENCE CASE



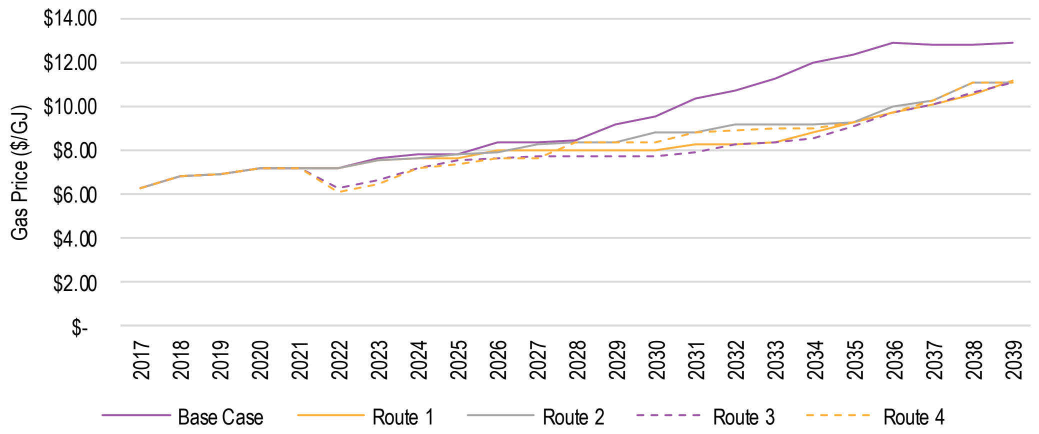
Note: Price profiles for Routes 1 – 4 are for gas delivered into West–East Pipeline at $5/GJ (real 2017). Wholesale prices delivered to city gate, expressed in real 2017-dollar terms.

SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

4.10.2 Melbourne

Figure 4.37 compares the modelled gas prices at Melbourne under Routes 1 to 4 with the Reference Case prices. Under the Reference Case, prices rise in real terms to a plateau level of around $13/GJ which represents the transport-adjusted cost of diverting LNG away from the Gladstone plants. All four West–East Pipeline routes deliver significant and broadly similar price reductions which tend to increase over time to as much as $3.50/GJ. The price outcomes for the Moomba-terminating options (Routes 1 and 3) deliver somewhat better price outcomes than those route options delivering gas via Adelaide.

FIGURE 4.37 COMPARISON OF MODELLED GAS PRICES AT MELBOURNE, ROUTES 1 TO 4 AND REFERENCE CASE



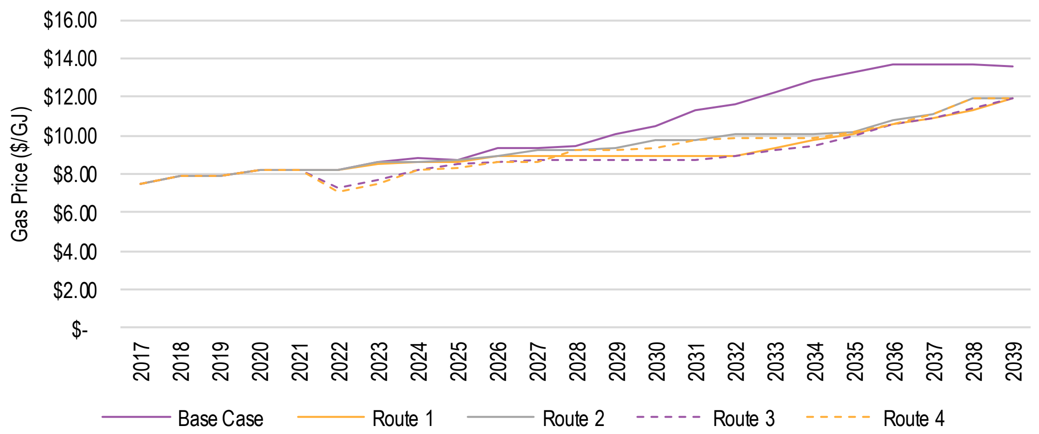
Note: Price profiles for Routes 1 – 4 are for gas delivered into West–East Pipeline at $5/GJ (real 2017). Wholesale prices delivered to city gate, expressed in real 2017-dollar terms.

SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

4.10.3 Sydney

Figure 4.38 compares the modelled gas prices at Sydney under Routes 1 to 4 with the Reference Case prices. Under the Reference Case, prices rise in real terms to a plateau level of almost $14/GJ which represents the transport-adjusted cost of diverting LNG away from the Gladstone plants. All four West–East Pipeline routes deliver significant and broadly similar price reductions which tend to increase over time to around $3.50/GJ. The price outcomes for the Moomba-terminating options (Routes 1 and 3) deliver significantly better price outcomes than those route options delivering gas via Adelaide.

FIGURE 4.38 COMPARISON OF MODELLED GAS PRICES AT SYDNEY, ROUTES 1 TO 4 AND REFERENCE CASE



Note: Price profiles for Routes 1 – 4 are for gas delivered into West–East Pipeline at $5/GJ (real 2017). Wholesale prices delivered to city gate, expressed in real 2017-dollar terms.

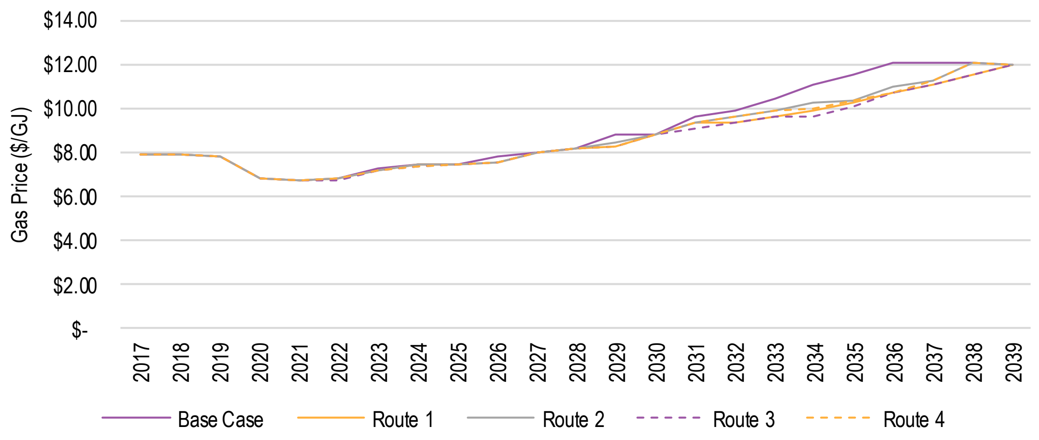
SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

4.10.4 Brisbane

Figure 4.39 compares the modelled gas prices at Brisbane under Routes 1 to 4 with the Reference Case prices. Under the Reference Case, prices rise in real terms to a plateau level of almost $12/GJ which represents the transport-adjusted cost of diverting LNG away from the Gladstone plants. All four

West–East Pipeline routes deliver significant and broadly similar price reductions, but only in the period after 2030. The price differentials reach a maximum of just over $1.00/GJ but fall toward the end of the modelling period so that by 2039 all prices sit at the LNG diversion level.

FIGURE 4.39 COMPARISON OF MODELLED GAS PRICES AT BRISBANE, ROUTES 1 TO 4 AND REFERENCE CASE



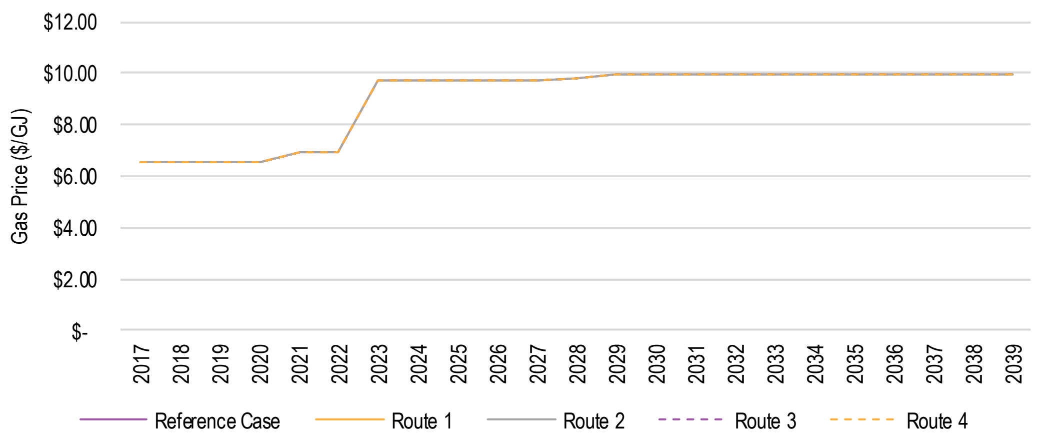
Note: Price profiles for Routes 1 – 4 are for gas delivered into West–East Pipeline at $5/GJ (real 2017). Wholesale prices delivered to city gate, expressed in real 2017-dollar terms.

SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

4.10.5 Western Australia

Figure 4.40 compares the modelled gas prices at Perth under Routes 1 to 4 with the Reference Case prices. Because no commercial interconnection between the West–East Pipeline and the Western Australian domestic market is assumed, the pipeline does not have any effect on prices in Western Australia. The sharp increase in gas prices in 2023 occurs in all cases, including the Reference Case, and is not associated with the West–East Pipeline. It is associated with a significant decline in aggregate production from the North West Shelf fields that commences in 2022 and results in a re-pricing of NWS gas into the Western Australian domestic market.

FIGURE 4.40 COMPARISON OF MODELLED GAS PRICES AT PERTH, ROUTES 1 TO 4 AND REFERENCE CASE



Note: Price profiles for Routes 1 – 4 assume gas delivered into West–East Pipeline at $5/GJ (real 2017). Wholesale prices delivered to city gate, expressed in real 2017-dollar terms.

SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

As discussed in section 4.4.3, the dedication of gas reserves to the West–East Pipeline has the potential to increase gas prices in Western Australia by increasing reliance on more expensive gas to service the local market. However, the extent of any modelled price effects is dependent on the source of the gas supplies dedicated to the West–East Pipeline.

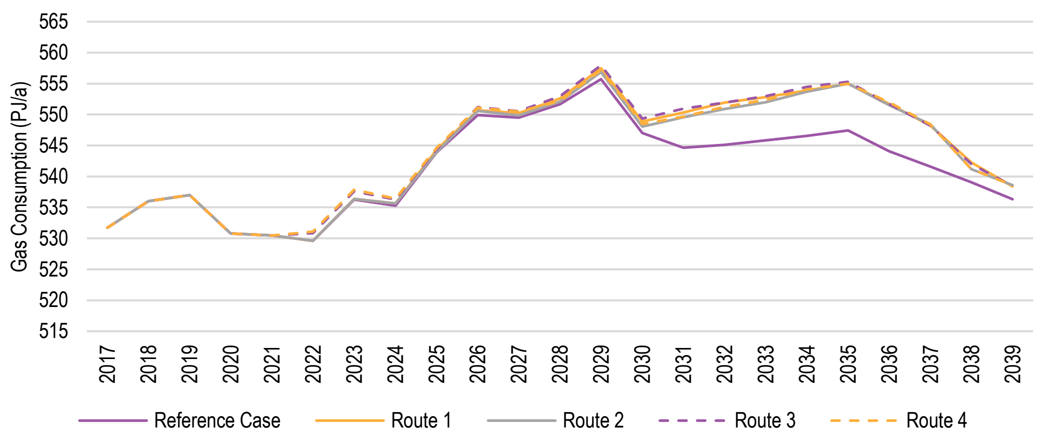
4.11 Modelled gas consumption

4.11.1 Eastern Australia

Figure 4.41 compares modelled levels of gas consumption in Eastern Australia under Routes 1 to 4 with the Reference Case. All four routes result in modestly higher levels of gas consumption—up to about 8 PJ/a against a Reference Case consumption level of about 550 PJ/a. Significant consumption effects are confined to the post-2030 period. The consumption impacts of all four route options are similar.

As expected, there are no differential consumption effects in Western Australia because of the necessary assumption that the West–East Pipeline has no commercial interconnection with the Western Australian domestic market.

FIGURE 4.41 COMPARISON OF MODELLED GAS CONSUMPTION IN EASTERN AUSTRALIA, ROUTES 1 TO 4 AND REFERENCE CASE



Note: Consumption profiles for Routes 1 – 4 are for gas delivered into West–East Pipeline at $5/GJ (real 2017).

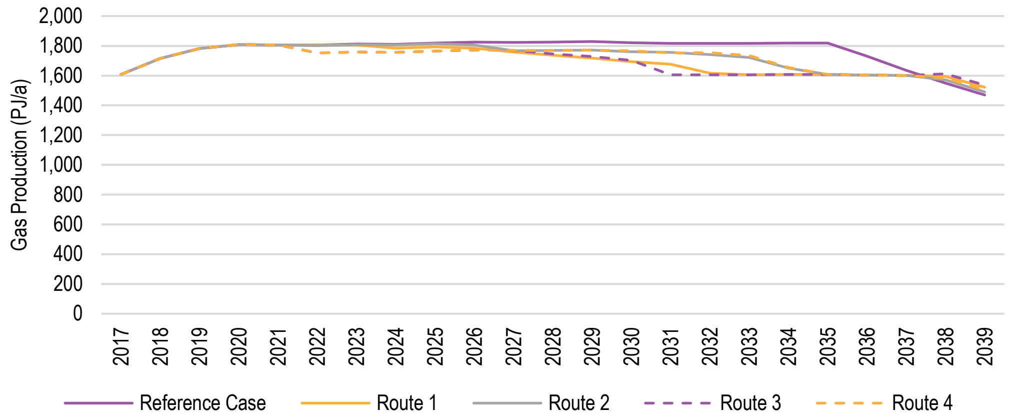
SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

4.11.2 Modelled gas production

Eastern Australia

Figure 4.42 compares modelled levels of gas production in Eastern Australia under Routes 1 to 4 with the Reference Case. All four routes show gas production that is lower than the Reference Case, particularly after 2030. This reflects the fact that the gas supply from Western Australia does not result in a corresponding increase in consumption. Most of the Western Australian supply substitutes for higher cost gas in Eastern Australia, production of which is deferred. The Moomba-terminating options (Routes 1 and 3) have a greater impact in terms of suppressing Eastern Australian production levels, consistent with the idea that most of the gas delivered via the West–East Pipeline will displace high marginal cost CSG as feed to the Gladstone LNG plants. At the end of the modelling period (2038, 2039) production under the Reference Case falls below the West–East Pipeline Cases. This is because in the absence of the pipeline imports, higher levels of production in Eastern Australia result in earlier onset of reserves depletion.

FIGURE 4.42 COMPARISON OF MODELLED GAS PRODUCTION IN EASTERN AUSTRALIA, ROUTES 1 TO 4 AND REFERENCE CASE



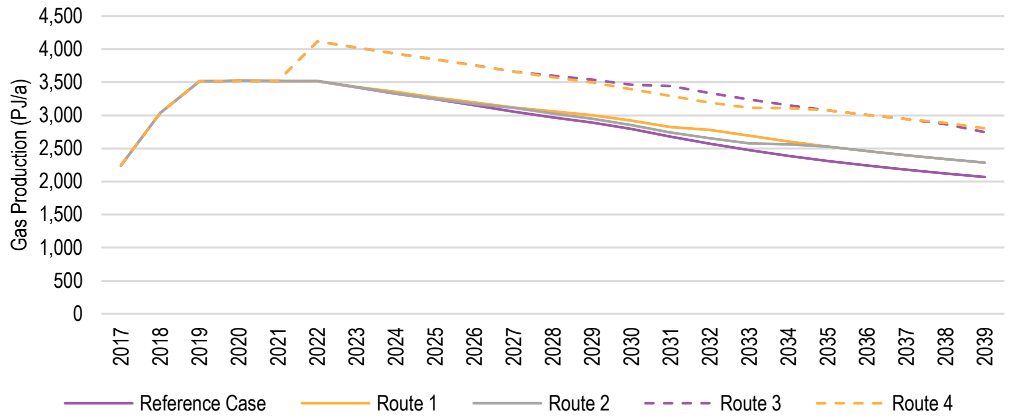
Note: Production profiles for Routes 1 – 4 are for gas delivered into West–East Pipeline at $5/GJ (real 2017).

SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

Western Australia

Figure 4.43 compares modelled levels of gas production in Western Australia under Routes 1 to 4 with the Reference Case. The routes commencing at Dampier (Routes 1 and 2) show modest increases in total gas production, reflecting the additional quantities of gas produced for supply to Eastern Australia. The increases in production are much larger for Routes 3 and 4 which commence near Broome, because these cases assume that onshore delivery of gas from the Browse Basin occurs in association with supply into a new 10 mtpa LNG plant. In these cases, the sharp increase in aggregate production from 2022 is associated mainly with supply into the new LNG plant.

FIGURE 4.43 COMPARISON OF MODELLED GAS PRODUCTION IN WESTERN AUSTRALIA, ROUTES 1 TO 4 AND REFERENCE CASE



Note: Production profiles for Routes 1 – 4 are for gas delivered into West–East Pipeline at $5/GJ (real 2017).

SOURCE: ACIL ALLEN CONSULTING GASMARK MODELLING

4.12 Potential returns on investment: the critical importance of contracted capacity and timing

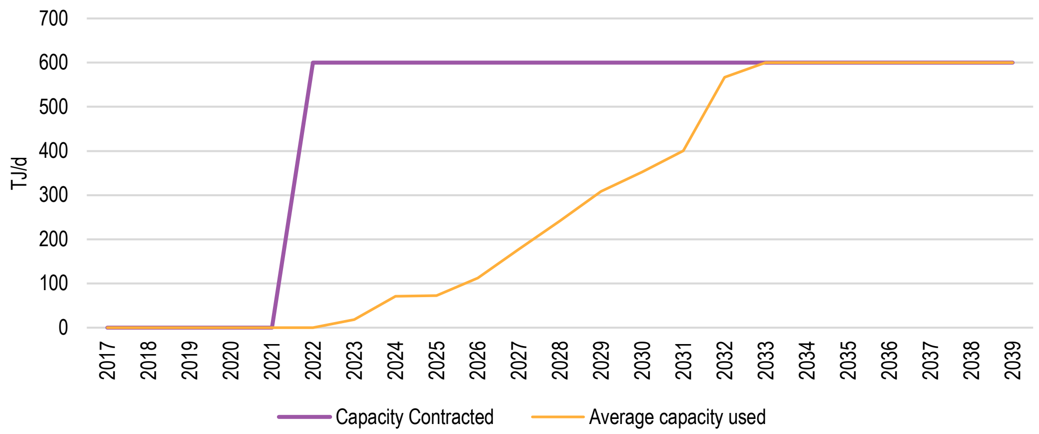
The preceding analysis indicates that the owner of the West–East Pipeline could achieve a pre-tax real rate of return of 8 per cent by constructing and operating the pipeline following the Route 1 alignment from Dampier to Moomba and charging shippers a tariff of $2.91/GJ (real 2017-dollar terms).

That finding was, however, subject to several critically important assumptions about the level of contracted capacity on the pipeline and the timing of capital outlays relative to the timing of tariff revenues. The modelling was undertaken on the **most optimistic basis** in terms of contracted capacity and timing. Specifically, it was assumed that:

— shippers would contract and pay for all the capacity in the pipeline (600 TJ/d) on a firm capacity basis.
— payment for the full contracted capacity would commence in the year after completion of construction, despite the fact that actual pipeline throughput would have a slow initial ramp-up.

Figure 4.44 compares the modelled ramp-up of annual pipeline throughput (expressed on an equivalent TJ/d basis) with the assumed capacity contract profile for the West–East Pipeline (Route 1, $5/GJ gas into pipe, no WA domestic gas interconnection). There is a large initial wedge of capacity being paid for, but not fully utilised. This is not an unreasonable assumption—there are examples of transmission pipelines in Australia for which foundation shippers booked and paid for all initial capacity despite a ramp-up in actual throughput. However, the longer the period between pipeline commissioning and full utilisation of capacity, the less likely it is that shippers will underwrite the ramp-up period.

FIGURE 4.44 WEST–EAST PIPELINE: ASSUMED CAPACITY CONTRACT PROFILE VS MODELLED PIPELINE THROUGHPUT



Note: Route 1 (Dampier to Moomba); $5/GJ gas feed into pipe, tariff at $2.91/GJ at average 80% load factor, real 2017, no WA domestic gas interconnection
SOURCE: ACIL ALLEN CONSULTING ANALYSIS

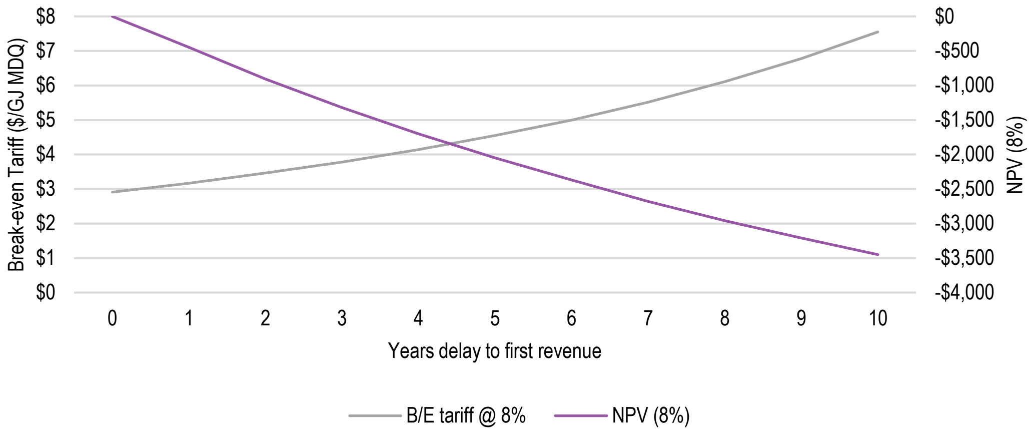
At the other extreme, shippers could agree to pay only for gas actually shipped, so that revenues would follow the 'average capacity used' profile in **Figure 4.44**. If pipeline construction was to proceed at the same time as assumed for modelling purpose (2020 and 2021) and tariffs were held at the same rate ($2.91/GJ at average 80% load factor) the NPV(8%) of the project would fall to –$2.56 billion, with an internal rate of return (IRR) of just 2.9% over a 25-year operating life. To restore the project to an 8% IRR (NPV at 8% equal to zero), the unit tariff would need to rise from $2.91/GJ to $5.35/GJ. All else being equal, this would push up the delivered cost of gas by almost $2.50/GJ resulting in lower, slower market uptake. As shown in **Figure 4.8**, an increase of $2 to $3/GJ in the cost of gas would defer the ramp-up of throughput by 4 to 5 years, further damaging the project economics and requiring an even higher tariff to achieve targeted rates of return. It is unlikely under this scenario that a sustainable balance between delivered gas cost and required pipeline revenue could be found unless the construction of the pipeline was deferred to a time when much quicker ramp-up of throughput could be achieved.

An alternative way of considering the problem of timing of construction is to measure the impact of delays between construction and the commencement of revenue generation. As explained above, the assumption has been made for the purposes of this analysis that foundation shippers will pay for all the capacity in the pipeline from the first year after completion of construction. On that basis, the foundation tariff rate of $2.91/GJ at average load factor of 80% yields an 8% IRR on a pre-tax, real basis over a 25-year project life.

Now consider what happens if the foundation shippers agree to pay for all the capacity in the pipeline but not until closer to the time when the pipeline will be heavily utilised.

Figure 4.45 shows the effects on project economics (NPV, 8%) as the delay between capital investment and receipt of revenue increases from 1 year to 10 years, while holding the foundation tariff at the base level of $2.91/GJ. It also shows the break-even tariffs that would need to be charged (without loss of contracted capacity) in order to restore the project to an 8% pre-tax real return on investment. Clearly if the capital investment gets too far ahead of the tariff revenue stream, project economics are severely impacted; the tariffs required to achieve a commercial rate of return become unsustainably high with the result that ramp-up of throughput would be further delayed and the commercial prospects of the project would spiral downwards.

FIGURE 4.45 IMPACT OF DELAYS IN RECEIPT OF TARIFF REVENUES ON PROJECT NET PRESENT VALUE AND BREAK-EVEN TARIFFS

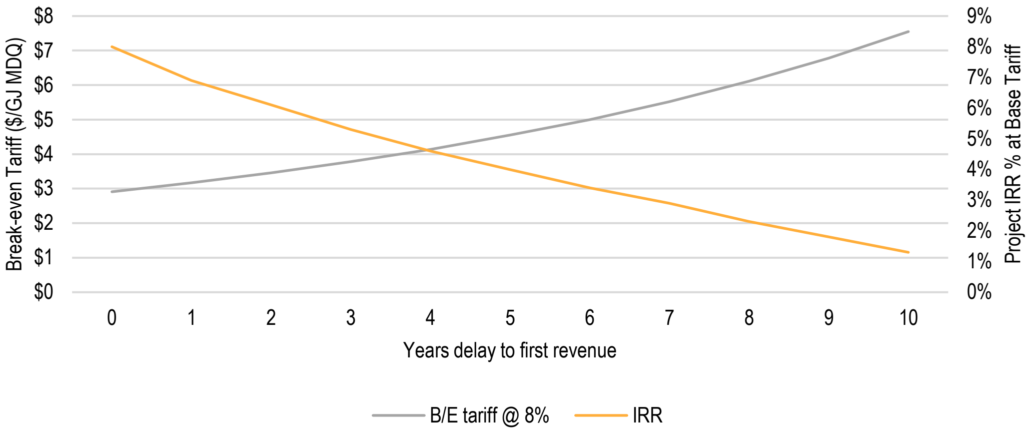


Note: Route 1 (Dampier to Moomba); $5/GJ gas feed into pipe, tariff at $2.91/GJ at average 80% load factor, real 2017, no WA domestic gas interconnection

SOURCE: ACIL ALLEN CONSULTING ANALYSIS

Figure 4.46 shows the corresponding comparison between the delay in receipt of revenue and project internal rate of return (IRR), again while holding the foundation tariff at the base level of $2.91/GJ. The message is similarly stark—the economics of the project would be severely impacted by pre-emptive investment in the pipeline ahead of the establishment of a firm foundation customer tariff revenue stream.

FIGURE 4.46 IMPACT OF DELAYS IN RECEIPT OF TARIFF REVENUES ON PROJECT RATE OF RETURN AND BREAK-EVEN TARIFFS



Note: Route 1 (Dampier to Moomba); $5/GJ gas feed into pipe, tariff at $2.91/GJ at average 80% load factor, real 2017, no WA domestic gas interconnection

SOURCE: ACIL ALLEN CONSULTING ANALYSIS

5 ROUTE ASSESSMENT AND DESIGN

5.1 Introduction

5.1.1 Conceptual pipeline routes

At the commencement of the study GHD and ACIL developed 'straw man' pipeline scenarios to assist in generating discussion during the consultation phase of the project and to test the base assumptions guiding the pre-feasibility study.

Demand assumptions

It is self-evident that for a 2,000 – 3,000 km pipeline to have a market competitive gas transportation tariff it needs to transport a large volume of gas over a long period of time. As a starting point, a pipeline capacity of 500-600 TJ/day was assumed. A pipeline of this capacity could deliver 150 – 200 PJ/year depending on the seasonal load profile in the downstream market. It was further assumed that, in order to amortise this pipeline investment, it would be necessary to be able to maintain this rate of gas delivery for at least 20 years.

Under this scenario, the pipeline would need to secure customer demand equivalent to approximately one-third of the current east coast domestic demand. Consequently, the connection point to the east coast market needs to be able to readily access the major demand centres in the east coast market.

To ensure supply for a minimum 20-year period the pipeline would require reserves of around 4,000 PJ to be committed to the project. Consequently, the receipt point needs to be a location where gas reserves of at least 4,000 PJ could be accessed.

Receipt Point assumptions

Western Australia has abundant reserves of natural gas located the off-shore Carnarvon and Browse Basins. The most obvious candidate receipt point would be near Dampier, where the North West Shelf and Pluto LNG plants are located. Gas from the North West Shelf project is currently supplied into the Western Australian domestic market as well as being converted into LNG for export. Other major sources of gas production for LNG and domestic use are located in the area south of Dampier (including the Gorgon, Wheatstone and Pluto projects) and there are domestic gas production facilities at Devil Creek and Varanus Island. The Dampier area receipt point anticipates a further development of the Carnarvon Basin gas fields and the construction of additional gas processing facilities to supply gas into the West–East Pipeline.

A second receipt point near Broome was chosen enable Browse Basin to come on shore. This would also enable the pipeline to take gas from the prospective on-shore Canning Basin.

Delivery Point assumptions

The Moomba hub is the most obvious candidate delivery point for the pipeline, enabling Western Australian gas to interconnect with the east coast grid and to then be transported by existing pipelines into the South Australian, NSW and Queensland markets as well as accessing Victoria either from Adelaide (via the SeaGas Pipeline) or from NSW via the Moomba-Sydney Pipeline (MSP) and the NSW – Victoria Interconnect, into the Victorian Transmission System (VTS). A Moomba tie-in would also have the potential enable the pipeline users to access gas storage and compression services at the existing Moomba gas production and processing facilities operated by the Cooper Basin Joint Venture.

A second delivery point was considered in the vicinity of Adelaide. This would enable the pipeline to connect directly into a demand centre in Adelaide. It would also provide interconnection with both the Moomba-Adelaide Pipeline (MAP) and the SEAGas Pipeline enabling delivery to the Moomba hub (via MAP flowing north) and to the Victorian market (via SEAGas flowing east).

TABLE 5.1 ROUTE ALTERNATIVES SUMMARY

Route	Receipt Point	Delivery Point	Capacity (TJ/Day)
Route 1	Carnarvon Basin Karratha vicinity	Moomba	500-600
Route 2	Carnarvon Basin Karratha vicinity	Adelaide vicinity	500-600
Route 3	Browse Basin Broome vicinity	Moomba	500-600
Route 4	Browse Basin Broome vicinity	Adelaide vicinity	500-600

Consultation feedback on alternative route assumptions

The parties contributing to the consultation process generally indicated that the base assumptions regarding receipt and delivery points were a logical starting point. Most indicated that they considered a tie-in to Moomba to be the most obvious and likely to achieve the necessary market access. Key feedback from the consultation in relation to route selection was as follows:

— An additional route scenario was proposed during consultation to target a delivery point in the vicinity of Tennant Creek, providing a connection to the Northern Gas Pipeline (NGP) currently under construction. This would require an expansion of the NGP and either a new pipeline to connect the NGP near Mount Isa to the Wallumbilla hub in Queensland, or alternatively a major expansion and reversal of flow on the existing Carpentaria Pipeline providing access to the South West Queensland Pipeline and the Moomba hub, via Ballera. ACIL Allen undertook market modelling of a connection to Tennant Creek, NGP expansion and new pipeline from Mount Isa to Wallumbilla but found that market uptake of gas was significantly reduced and deferred when compared to the direct Moomba connection routes (see section 4.8.1). On this basis the northern route was not subjected to further engineering assessment.

— Browse Basin gas was most likely to come on shore at Dampier, and therefore a receipt point at Dampier was more likely. Furthermore, because Broome has been flagged as a sensitive environmental and native title area, future studies should look at alternative locations for Browse Basin gas.

— Previous in-house studies by other market participants had identified 600 TJ/day to be the most economical demand profile.

This feedback was utilised to refine the routes under analysis and to inform the final selection of the preferred route.

5.2 Route Selection and Multi Criteria Assessment

5.2.1 Approach

InDeGO route selection and multi-criteria assessment

Infrastructure Development Geospatial Options (InDeGO) is a multi-criteria assessment and route selection approach developed by GHD to scientifically and mathematically identify potential and optimum routes for linear infrastructure developments. The InDeGO multi-criteria assessment tool was used to assess the potential pipeline route options to deliver gas from Western Australia to the east coast gas market.

InDeGO mixes traditional understanding of multi-criteria analysis with specific location-based geographic understanding (Geographic Information Systems – GIS) to identify potential pipeline route options. The approach makes use of geographically characterised social, economic, engineering, planning and environmental criteria.

The InDeGO approach used for the West-East Pipeline route selection is summarised in **Figure 5.1**, with key elements described in the following sections.

FIGURE 5.1 SUMMARY OF THE INDEGO MULTI-CRITERIA ANALYSIS APPROACH

SOURCE: GHD

Criteria definition

A series of workshops were held with the Project Team and key specialists to define the criteria to be used in the analysis, and to agree the appropriate basis for measuring and scoring. Criteria were defined across four themes – environmental, social, physical and infrastructure. For each criterion, a scoring system was defined to identify locations with high or low suitability for a gas pipeline route. Proximity-based measures were created and assigned one of the following possible scores:

— 1 – no constraints
— 10 – low constraints
— 20 – some constraints
— 40 – highly constrained
— 999 – not feasible.

A summary of the chosen criteria is provided in **Table 5.2**, and a full definition of each criterion (along with measures and scores) is provided in Appendix C.

TABLE 5.2 SUMMARY OF INDEGO CRITERIA

Environmental	Social
– Proximity to National and State Parks – Proximity to RAMSAR wetlands – Proximity to environmentally sensitive areas – Proximity to native vegetation areas – Probability of acid sulfate soils – *Proximity to contaminated sites**	– Proximity to urban/populated areas – Proximity to registered European heritage sites – Proximity to registered aboriginal heritage sites* – Proximity to existing and future agricultural land uses – Proximity to military sites – *Likelihood of native title claims***
Physical	**Infrastructure**

– Proximity to water bodies	– Proximity to road network
– Proximity to water courses	– Proximity to rail network
– Slope percentage	– Proximity to existing gas and oil pipelines
– *Soil type**	– Proximity to high voltage powerlines
– *Flood risk**	– Proximity to mine areas

* Suitable data sources were not available to support assessment of these criteria

** This criterion was excluded from the InDeGO process for this exercise, as it was overly prohibitive for suitable route selection, and requires further consideration.

SOURCE:

Data collation and pre-processing

From the criteria, specific datasets were identified, collated and created. Data was collated from the following sources:

Western Australian, South Australian and Northern Territory Governments

- Geoscience Australia
- CSIRO
- National Native Title Tribunal
- National Heritage List Spatial Database
- Western Power

Full details of data sources and data sets used are provided in Appendix C.

Four of the identified criteria could not be assessed because suitable and reliable data representing these criteria could not be sourced and processed within the timeframe available for route selection. These criteria included:

- Proximity to contaminated sites
- Proximity to aboriginal cultural heritage sites
- Soil suitability
- Flood risk

Likelihood of native title claims was identified as an important criterion but was not included in the assessment because it was overly prohibitive for route selection, and an objective approach to determine likelihood of native title claim was not clearly established.

All of these criteria would need to be considered as part of any future feasibility study (refer to Section 5.2.3 - Matters for further consideration). Initial measures and scoring for these criteria have already been established, and the required data sources have been identified, but not yet sourced. This means that if a full feasibility study is undertaken and appropriate data has been sourced, the inclusion of these criteria into the route analysis will be straightforward.

Some datasets required filtering or pre-processing prior to use. For example, the water bodies dataset contained far too many features to enable a rapid assessment over such a broad geographic area. To make this data easier to handle for the pre-feasibility assessment, minor water bodies smaller than 2.5ha (that is, smaller than the 500x500m grid cell size used for the modelling and route selection) were excluded.

Weightings

The use of weightings allows the Project Team and other relevant stakeholders to rank criteria in relative importance using a ‘weight matrix’. A workshop was undertaken to identify the weightings for this analysis.

The weighting value assigned to each criterion reflects the importance or potential level of impact on the assessment process of that criterion relative to each of the other criteria. This “pairwise” weighting approach assesses, for each pair of criteria, which of the two is the more important.

Initially, the InDeGO modelling was run without weighting to review the unweighted route selection and to identify constraints requiring higher or lower weightings. Following this, the model was re-run with weightings as agreed by the Project Team to reflect the relative importance of the chosen criteria. The weighted model was used to identify routes that were more heavily influenced by high priority criteria such as National Parks and RAMSAR wetlands, and less heavily influenced by lower priority criteria such as proximity to rail.

FIGURE 5.2 PAIRWISE WEIGHTING OF THE INDEGO CRITERIA

	Road Network	Rail Network	High voltage major Powerlines	Proposed and Major Mines	Pipelines	Native Vegetation	Acid Sulfate Soils	Ramsar Wetlands	National and State Parks	Environmentally Sensitive Areas	Registed European Heritage (state and federal)	Existing and Future Agricultural Use	Urban/Populated Areas	Military Sites	Water Body	Water Course	Slope	TOTAL	Weight
Road Network		1	1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	3	**2%**
Rail Network	0		1	0	0	0	1	0	0	0	0	0	0	0	0	0	0	2	**1%**
High voltage major Powerlines	0	0		0	0	0	1	0	0	0	0	0	0	0	0	0	0	1	**1%**
Proposed and Major Mines	1	1	1		0	0	1	0	0	0	0	1	0	0	0	0	1	6	**4%**
Pipelines	1	1	1	1		0	1	0	0	0	0	1	0	0	0	0	1	7	**5%**
Native Vegetation	1	1	1	1	1		1	0	0	0	0	1	0	0	0	0	1	8	**6%**
Acid Sulfate Soils	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	0	**0%**
Ramsar Wetlands	1	1	1	1	1	1	1		1	1	1	1	1	0	1	1	1	15	**11%**
National and State Parks	1	1	1	1	1	1	1	0		1	1	1	1	0	1	1	1	14	**10%**
Environmentally Sensitive Areas	1	1	1	1	1	1	1	0	0		0	1	1	0	1	1	1	12	**9%**
Registed European Heritage (state and federal)	1	1	1	1	1	1	1	0	0	1		1	1	0	1	1	1	13	**10%**
Existing and Future Agricultural Use	1	1	1	0	0	0	1	0	0	0	0		0	0	0	0	1	5	**4%**
Urban/Populated Areas	1	1	1	1	1	1	1	0	0	0	0	1		0	1	1	1	11	**8%**
Military Sites	1	1	1	1	1	1	1	1	1	1	1	1	1		1	1	1	16	**12%**
Water Body	1	1	1	1	1	1	1	0	0	0	0	1	0	0		1	1	10	**7%**
Water Course	1	1	1	1	1	1	1	0	0	0	0	1	0	0	0		1	9	**7%**
Slope	1	1	1	0	0	0	1	0	0	0	0	0	0	0	0	0		4	**3%**
																	TOTAL	136	**100%**

SOURCE: GHD ANALYSIS

The final pairwise weightings used for the route selection are shown in **Figure 5.2**.

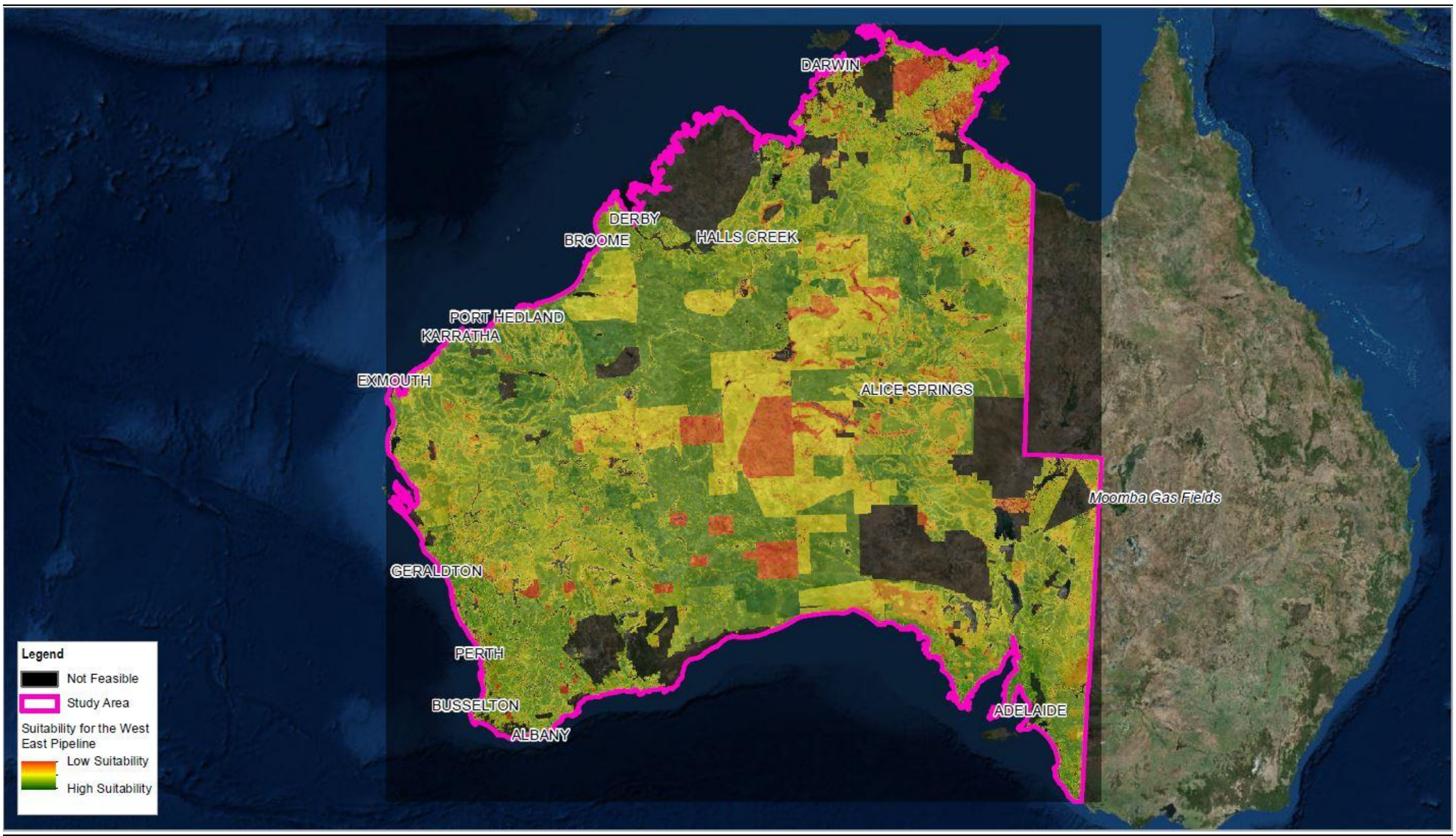
Modelling

A desktop modelling process was used to generate a route suitability surface using the identified criteria, scoring and weightings. This model utilises an overlay approach that requires all data to be converted into a cell-based grid (raster). Due to the large size of the study area (more than two thirds of the Australian continent), and the high-level nature of the pre-feasibility study, a relatively large grid size of 500m was chosen. All datasets were resampled to this grid size.

Figure 5.3 illustrates how the InDeGO model allows multiple overlays to be brought together to form a 'route suitability surface'. Essentially the route suitability surface is a total 'score' obtained for each data point by adding up the score for that data point in each layer (criterion). Low scores indicate low overall levels of constraint and high indicate high overall levels of constraint.

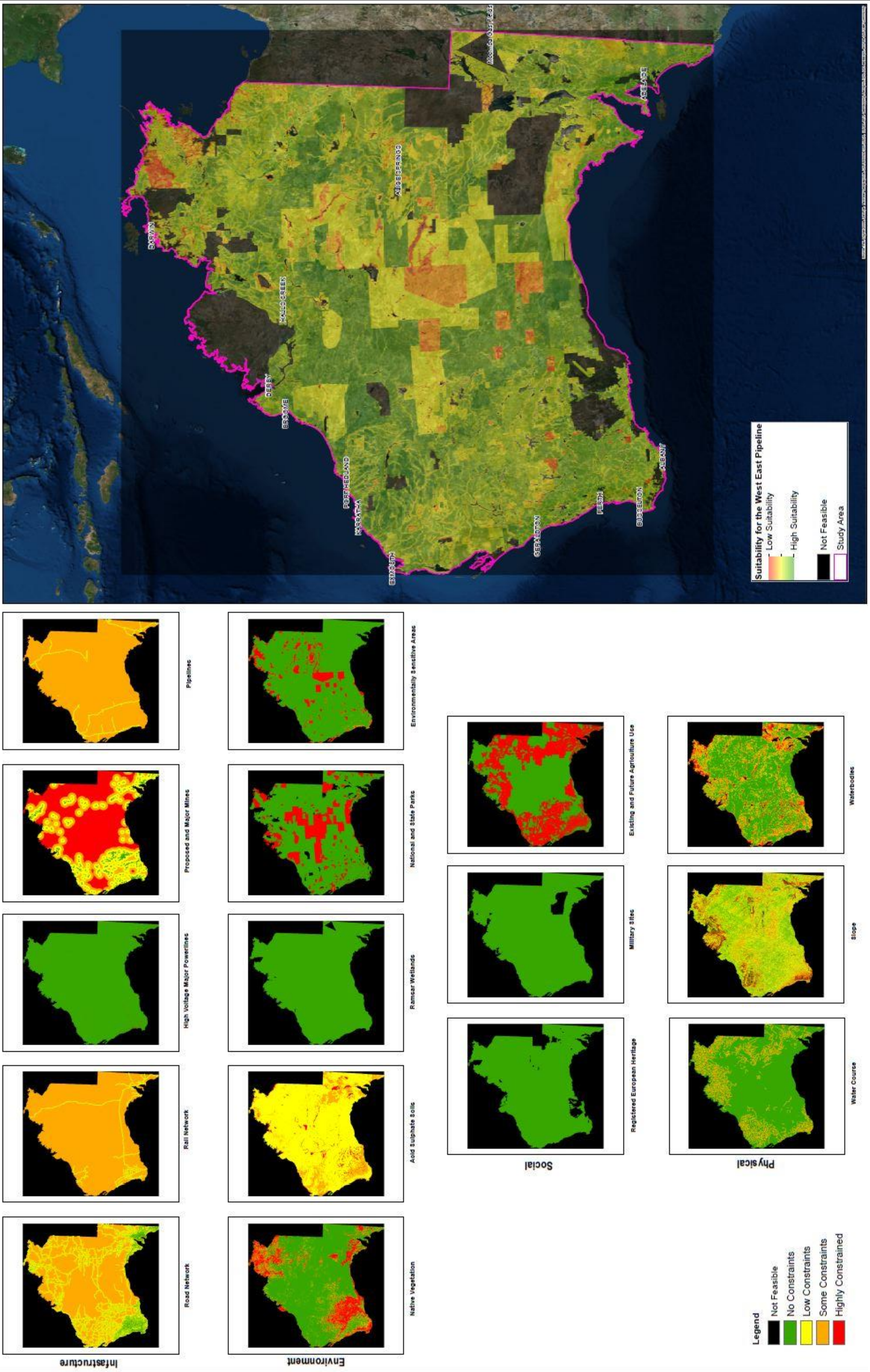
A more detailed representation of how the individual criteria combine to produce the route suitability surface is provided in **Figure 5.4**.

FIGURE 5.3 ROUTE SUITABILITY SURFACE FOR WEST–EAST PIPELINE



SOURCE: GHD

FIGURE 5.4 ROUTE SUITABILITY SURFACE LAYER DETAIL FOR WEST–EAST PIPELINE



Once the route suitability surface was created, the next step involved calculating the cost to traverse from each start point to each end point. For the purposes of this pre-feasibility study, we have assessed two possible start points (Karratha vicinity and Broome vicinity) connecting to two possible end points (Moomba and Adelaide). In each case, an appropriate start and end location was chosen based on logical connection points with existing or prospective new pipeline infrastructure.

The InDeGO model was used to determine the least cost path between each start point and end point. This resulted in four optimised routes that represent the least-cost combination of constraints and distance based on the criteria used for the analysis. These four routes are detailed in section 5.2.2.

Review and revision

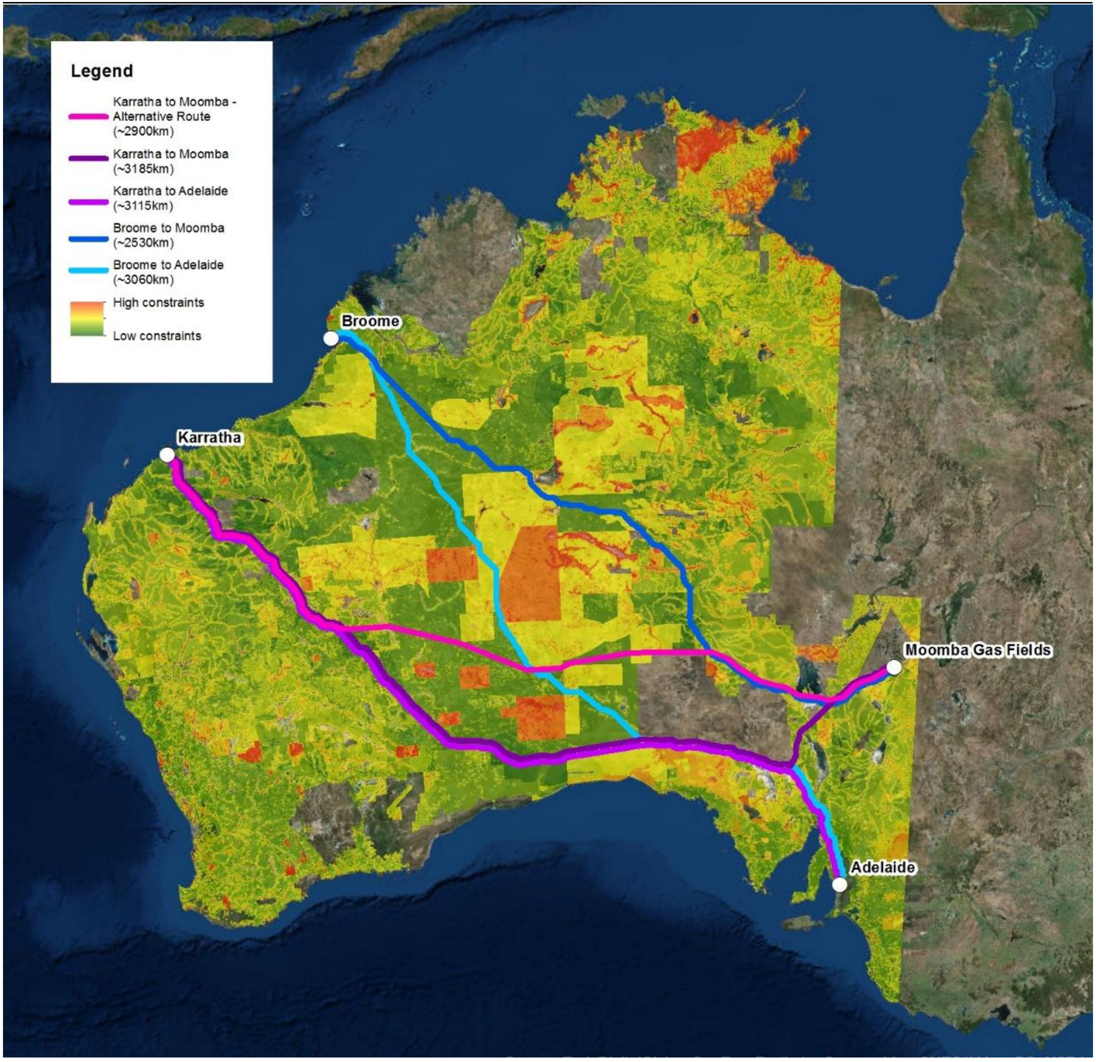
The InDeGO process used to undertake the route analysis for the West-East Pipeline involved several iterations of review and revision to ensure that the identified route alternatives were practical and appropriate. Based on review and revision of the initial outputs, several small changes were made to the criteria to optimise route identification.

The criterion regarding proximity to existing and proposed mine areas was modified after review. Initially, the measures for this criterion were designed to make it more attractive to run the pipeline route near (but not within) existing or proposed mine areas. This was done with the intention of capturing the potential for the West–East Pipeline to enhance regional mineral resource development opportunities by improving access to energy supply. However, after running the model it became apparent that, because of the large number of existing and proposed mine areas in south-western Western Australia, the route was being inappropriately deviated to service these areas at the expense of a more direct pipeline route. The weight given to proximity to mine areas was therefore reduced resulting in identified optimal routes that were more direct and efficient.

5.2.2 Assessment

The optimal routes for the West–East Pipeline, between the two defined starting points and the two end points, as defined by the InDeGO multi-criteria assessment are shown in **Figure 5.5**.

FIGURE 5.5 OPTIMAL ROUTE ALIGNMENTS FOR ALTERNATIVE START AND END POINTS FOR THE WEST–EAST PIPELINE (ROUTES 1 TO 4)



SOURCE: GHD INDEGO MODELLING

The routes shown above in **purple** and **blue** represent the optimal routes based on the agreed criteria and weighting. Areas of high constraints are represented in **red**, whilst areas of low constraint are in **green**.

Further iteration of these criteria may be required to produce a final route that is both practical and efficient. The high weighting attached to national and state parks meant that the optimised routes go out of their way to avoid crossing these areas. The resultant routes are far longer than they would be if the weighting on these areas was lower. There may therefore be merit in re-running this analysis allowing for the route to more easily cross national and state parks, thus providing a more direct path. This is particularly relevant for the Karratha to Moomba route, which deviates a long way south to avoid national and state parks in the centre of the study area, skirts the southern edge of the Woomera Prohibited Military Area, and then backtracks north to connect at Moomba. A more direct route could pass through small sections of state park and run north of the military zone, reducing the total route length by between 200 and 300 km. The route shown above in **pink** is an alternative (and more direct) route from Karratha to Moomba which represents the likely optimal path if the modelled cost of traversing areas of national and state park was reduced.

5.2.3 Matters for further consideration

The following route selection issues were identified for further consideration if more detailed feasibility studies of the West–East Pipeline are undertaken in the future:

— Further refinement of criteria and weightings to optimise the route selection, focusing on the cost of traversing national and state parks.

— Inclusion of the criteria that were excluded due the lack of availability of suitable data, including proximity to contaminated sites, proximity to aboriginal cultural heritage sites, soil suitability and flood risk.

— Proper consideration of likelihood of native title claims, and how this may influence the route selection.

— Inclusion of consistent national data sets, rather than state datasets of various levels of accuracy.

— Inclusion of more complex data for assessments at a higher level of detail within the broad corridors identified by the pre-feasibility assessment. For example, more detailed data on water bodies (where smaller water bodies are not filtered out of the process) should be used to determine the specific route alignment within the broad corridor(s) defined in this initial stage.

— Review of ‘no-go zones’ and specific constraints around start and end points. For example, the RAMSAR wetland area around Moomba is a broadly defined ‘triangular’ area, and this declared ‘no-go zone’ strongly influences the route that the pipeline may take at this end. Further investigations are required to determine whether it is feasible to run the pipeline more directly through this area if appropriate management and mitigation measures are put in place.

It is important to recognise that, at the pre-feasibility stage, the criteria applied to the MCA may not be exhaustive. There may be other constraints that will need to be considered as part of any more detailed feasibility studies of individual route options. A more comprehensive list of route selection criteria, scoring and weighting should be determined through a series of workshops with key project stakeholders, and potentially through public consultation. The existing routes should therefore be considered as broader ‘corridors’ within which more detailed route selections could be performed using a more exhaustive list of criteria and more detailed data.

5.3 Approvals assessment

5.3.1 Background

The West–East Pipeline will fall within the legal jurisdictions of the Commonwealth and the states/territories of Western Australia (WA), South Australia (SA) and potentially Northern Territory (NT), depending on the chosen route alignment.

The specific legislation that would govern the construction and operation of the West–East Pipeline and its associated infrastructure is the *Petroleum Pipelines Act 1969* and subsidiary regulations in Western Australia; the *Petroleum and Geothermal Energy Act 2000* in South Australia; and the *Energy Pipelines Act (NT)* in the Northern Territory. These Acts set out the requirements for the issue of licences required for the construction of gas pipelines. For construction to proceed under pipeline licences, the proponent would be required to obtain environmental and planning approvals under state/territory legislation, and to comply with the Commonwealth *Native Title Act 1993*.

This section of the report discusses the primary Commonwealth and state approvals required for the construction of the pipeline. Further approvals would be required to cover technical, environmental and safety issues associated with actual construction and operation of the pipeline.

The primary approvals for the West–East Pipeline covered in this report relate to:

— Pipeline licences

— Environmental approvals

— Land tenure

— Land access for planning purposes

Achieving approvals to build a pipeline that crosses state jurisdictions in an efficient and timely fashion will require co-operation and co-ordination between all jurisdictions given that the proponent will be required to satisfy the regulatory requirements for each jurisdiction. Co-ordination will be important in ensuring minimal risk of conflicting licence and other approval conditions. It will also be required to provide efficiency in the approvals processes, particularly where studies for environmental impact statements and management plans are concerned.

5.3.2 Commonwealth legislation

The relevant Commonwealth legislations applying to the West–East Pipeline are:

Native Title Act 1993

Environment Protection and Biodiversity Conservation Act 1999.

Native Title Act 1993

The *Native Title Act 1993* provides a national system for the ‘recognition and protection of native title and its co-existence with the national land management system’. The Act provides the means by which native title rights and interests that may exist over land or waters are acknowledged and addressed where the Project’s footprint impacts these rights.

Determining if native title exists or may exist over land, and what rights and interests may exist on a particular parcel of land, is complex and requires that the history of each parcel of land to be researched to establish whether or not a past act has extinguished native title. If native title exists or has been claimed to exist, then the rights and interests of the holders or claimants will need to be established.

In general terms, the grant of freehold land would have extinguished native title completely, while unallocated crown land would be expected to have unaffected native title that could have been established or claimed under the *Native Title Act*. In other cases, the land could still be open to claim. Any other tenure other than freehold land is best assumed to potentially subject to some form of native title that could be claimed, or may already have been established or claimed, under the Act.

Given the anticipated route of the West–East Pipeline, there will be very limited areas of freehold land that will be impacted. Most of the land will be Crown land (unallocated or pastoral lease) or land reserved for the use of indigenous people. As such, much of the pipeline route is, or may potentially be, subject to native title.

A team dedicated to the assessment of native title on each parcel of land and the identification of holders or claimants of that title for the purposes of the Act will be required. Specialists in meeting *Native Title Act* requirements for the issue of tenure for the agreed pipeline route will form part of the team.

Implications for schedule

The meeting of the requirements of the *Native Title Act* is complex and should be started as soon as practicable in the Project schedule and can occur in parallel with other approvals processes. It could require up to 12 months to identify the native title status of each parcel of land impacted by the Project and the holders/claimants of that title. Up to two years could be required to complete the *Native Title Act* requirements for each parcel of land.

Environment Protection Biodiversity Conservation Act 1999

This Project will require referral to the Department of the Environment and Energy (DoEE) under the *Environment, Protection and Biodiversity and Conservation Act 1999* (EPBC Act). There are certain to be impacts, likely to be determined ‘Significant’, on Matters of National Environmental Significance (MNES) as defined under the Act. These are the triggers for the need for a formal assessment of the Project as a ‘controlled action’. The impact on MNES is referred to the DoEE which then sets the required level of environmental assessment.

It is likely that the project would be assessed by the state/territory jurisdictions through which the pipeline will pass, under existing bilateral agreements. These allow for the state/territory to assess a proposal with Commonwealth advice in terms of impacted MNES. Approvals are then given separately under the state/territory legislation and the EPBC Act.

A desktop assessment of the 'likelihood of occurrence' of flora and fauna that are defined as being MNES matters will be required at the commencement of this approval process to determine the scope of work for the field investigations. Consultation with the DoEE on the final scope of work is recommended prior to the field investigations. An indicative list has been provided in a separate *EPBC Act Protected Matters Report* prepared using the online EPBC Act Protected Matters Tool, available through the Department of Environment and Energy website (see Appendix D). Those species identified as having a high likelihood of occurrence will need to be targeted in commissioned field surveys to provide the more detailed information required for environmental assessment reports.

Impacts on project-relevant MNES will be highest during construction due to logistic support activities such as the provision of access and material storage areas that will be later reinstated. The pipeline will be buried, allowing the majority of the impacted areas to be reinstated once construction is complete.

The project would most likely be classed as a 'Controlled Action'. As a result, offsets may be required since some disturbed areas will not be able to be restored, such as the corridor directly above the pipeline route, and areas required for operational needs. The agreed offsets will directly contribute to the ongoing viability of the protected matter impacted by the project and may be in the form of purchasing land with similar environmental values and protecting it by way of a conservation covenant on the Title. The Australian government has published its offset policy for the EPBC Act.[14]

Engagement with each jurisdiction's environmental regulator should occur concurrently with consultation undertaken with the Commonwealth ahead of any referral.

Implications for schedule

The Project will be assessed under the bilateral agreements between the Commonwealth and the relevant states/territories. Timing will be discussed under the sections of this report for each state/territory.

5.3.3 Western Australia

The relevant Western Australian legislation applying to the West–East Pipeline are:

— *Environmental Protection Act 1986* (EP Act; environmental approvals)
— *Petroleum Pipelines Act 1969* (PP Act; pipeline licence issue and land access for planning)
— *Land Administration Act 1997* (LA Act; land tenure and access)

Environmental Protection Act 1986

The West–East Pipeline is likely to be regarded by the Western Australian Environmental Protection Authority (WA EPA) as a significant proposal. The project would therefore require referral to the WA EPA under Part IV Division 1 of the EP Act for determination of the assessment level.

The WA EPA will generally consider the following in deciding if a project is a significant proposal:

— the sensitivity of the environment impacted
— the extent (including duration) of a Project's footprint
— resilience of the environmental to cope with the impact
— public interest about the likely effect of the proposal.

Because of the area of land likely to be impacted, and the environmental issues associated with building and operating the pipeline, the assessment level will most likely be set at the highest level, which is Public Environmental Review (PER).

There are five key stages in the WA environmental assessment process:

— referral of a proposal (by the proponent) to the EPA (s38)
— EPA decides whether to assess a referred proposal (s38 to s39B)
— assessment of the proposal (s40 to s43A)

[14] *Environment Protection and Biodiversity Act 1999*, Offset Policy, October 2012.

- EPA report on the assessment of a proposal (s44)
- Ministerial decision on proposal, and implementation of the proposal by the proponent in accordance with the conditions set out in the Ministerial decision (s45 to s48)

The Western Australian government signed a new assessment bilateral agreement with the Commonwealth Government on 3 October 2014. The agreement, which came into effect on 1 January 2015, allows WA to assess significant proposals on behalf of the Commonwealth.

All proposals that are likely to have a significant impact on MNES must still be referred under the EPBC Act for the Commonwealth to formally decide whether the proposal is a controlled action. Once this decision is made, the Project would be referred to the WA EPA. This would be the first step in the assessment process under the EP Act. When the assessment process is complete, an approval decision will be made by the Commonwealth under the EPBC Act, while the state Minister will make the state decision under the EP Act.

The formal assessment process will require the preparation and WA EPA approval of an Environmental Scoping Document (ESD) and an environmental document for public review based on the ESD. The ESD is usually prepared by the proponent. It describes the possible extent of impacts on factors and objectives set by the WA EPA and the environmental investigations required to support the assessment process. The ESD will include impact assessments and management plans for cultural heritage (*Aboriginal Heritage Act 1972* and *Heritage of Western Australia Act 1990*).

Public comment is invited at the referral and assessment stages. The EPA report is subject to a public appeals process. Any such appeals are determined by the Minister as part of the process of make a decision regarding the environmental acceptability of the Project.

Implications for schedule

A project of this scale may take up to two years (including field work and reporting) from the setting of an environmental assessment level for approvals to be provided by both Commonwealth and WA. Early consultation with the EPA would be recommended at the feasibility stage of the process. This consultation can occur in parallel with consultation on other approvals required for this Project. Approval under the EP Act is not required for survey purposes, assuming there is no environmental impact.

Petroleum Pipelines Act 1969 and Land Administration Act 1997

A licence granted under the PP Act authorises the holder to construct and operate a pipeline for the conveyance of petroleum (including natural gas). The issue of a licence is dependent on the proponent providing:

- final route
- technical details of the pipeline
- proposed lifetime of the pipeline
- evidence of title to land or approval from landowner (including the State on State Lands) for the use of the land for a pipeline
- compliance with the *Native Title Act*
- environmental approvals
- pipeline safety case

It is a pre-condition for the grant of a licence under the PP Act that the *Native Title Act* requirements for notification of native title holders and claimants of an application are met. There are no other *Native Title Act* requirements for the grant of the licence. However, compliance with other provisions of the *Native Title Act* is required as part of the process of obtaining tenure over the land required for construction and operation of the pipeline.

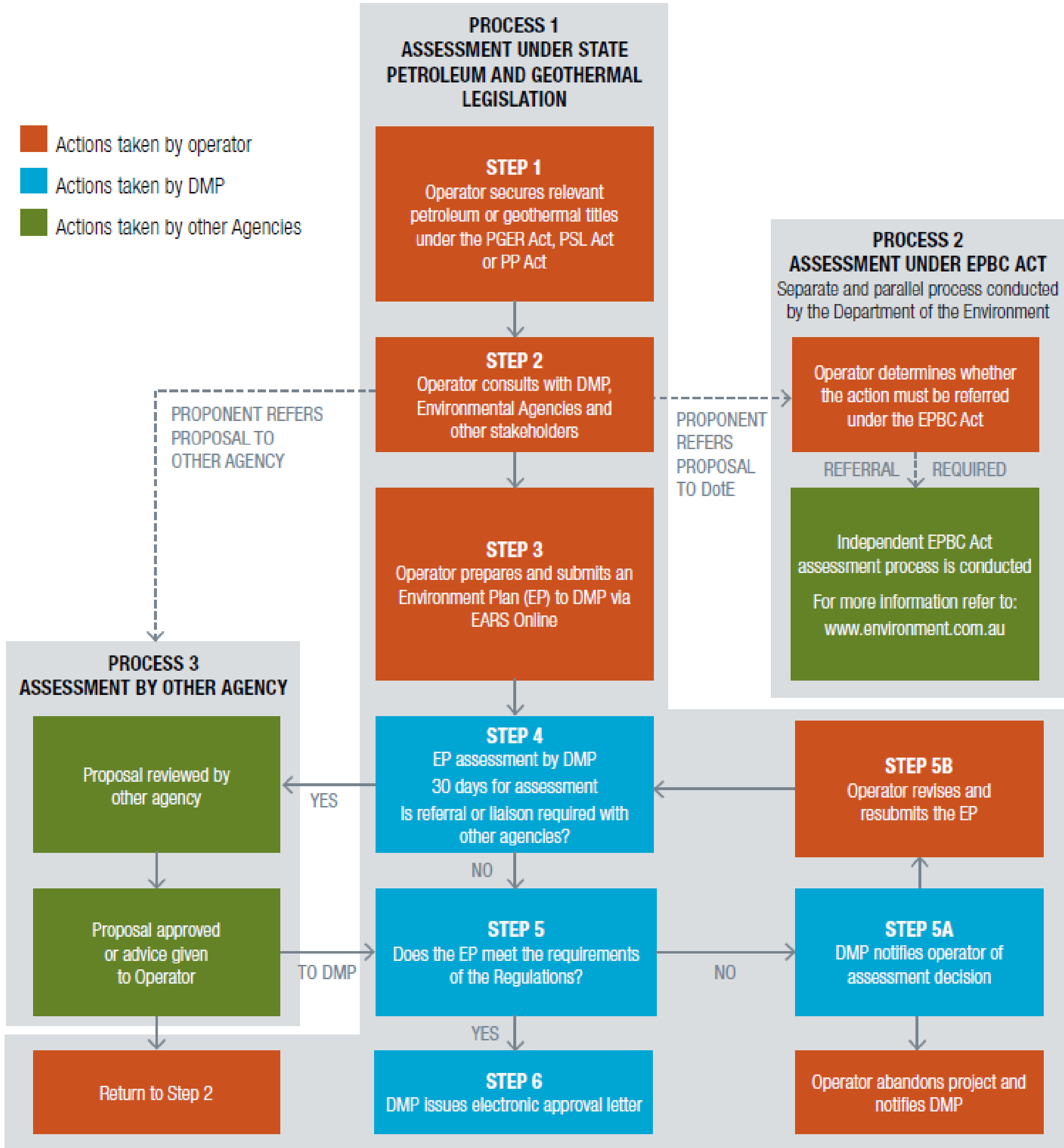
When a pipeline is to be constructed over land that is included within a registered Native Title claim or determination, agreement must first be reached with the Native Title parties concerning an easement or lease of land under the LA Act, or alternatively the land must be compulsorily acquired under Parts 9 and 10 of the LA Act.

Once all environmental approvals are obtained and all other PP Act requirements for the issue of a licence have been met, a licence will be issued to the pipeline proponent. A condition of this licence will require the preparation of a Construction Environmental Management Plan (CEMP) and an Operational Environmental Management Plan (OEMP), both of which must be approved by the Department of Mines, Industry Regulation and Safety (DMIRS) prior to commencement of construction.

Figure 5.6 summarises the process for environmental assessment of petroleum and geothermal projects (including gas pipelines) in Western Australia.

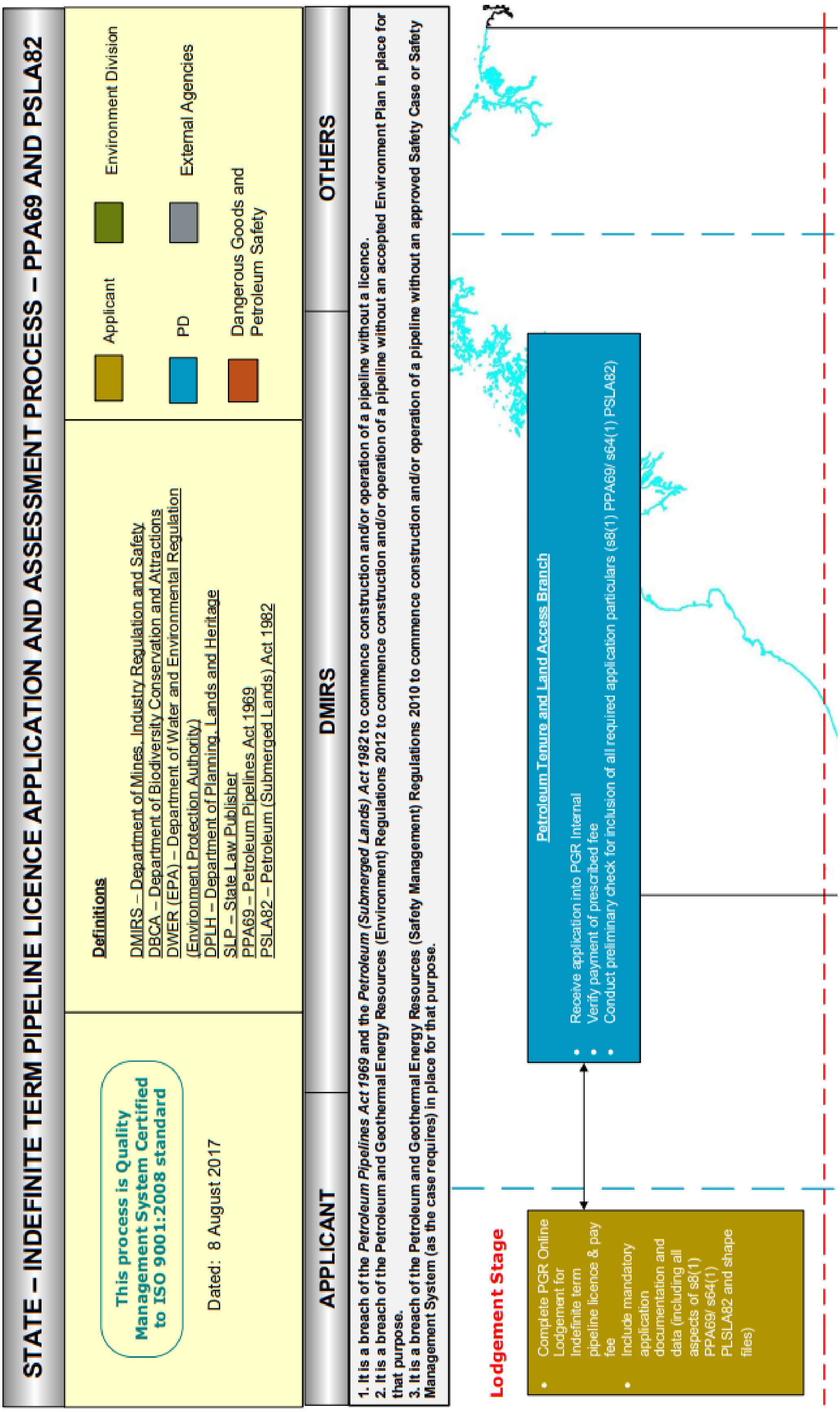
Figure 5.7 to **Figure 5.10** provide a more detailed explanation of the stages involved in the inter-agency pipeline approval processes that apply in Western Australia.

FIGURE 5.6 ENVIRONMENTAL APPROVALS PROCESS, WESTERN AUSTRALIA



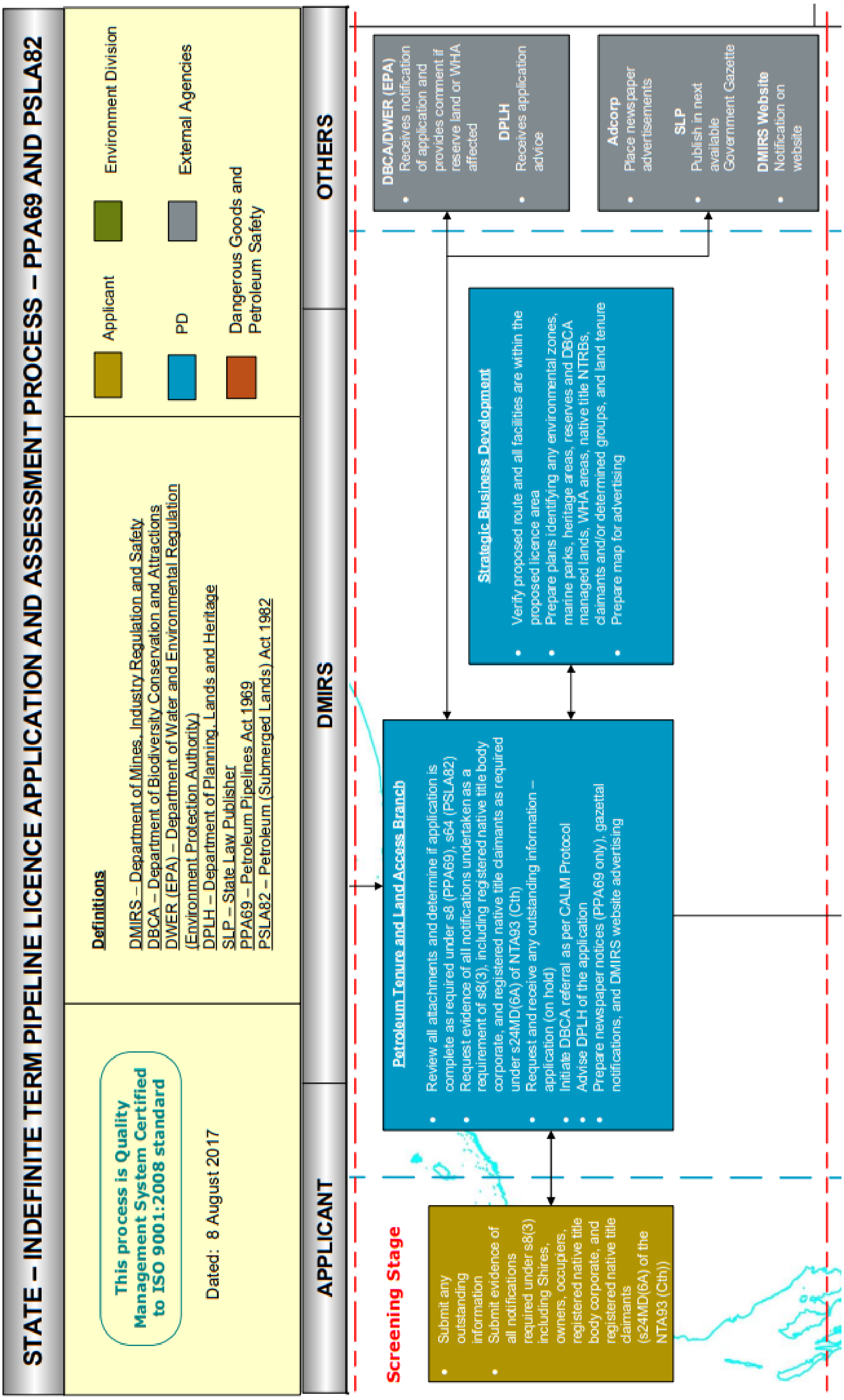
SOURCE: DEPARTMENT OF MINES AND PETROLEUM, WESTERN AUSTRALIA, 2016: 'GUIDELINE FOR THE DEVELOPMENT OF PETROLEUM AND GEOTHERMAL ENVIRONMENTAL PLANS IN WESTERN AUSTRALIA', NOVEMBER 2016

FIGURE 5.7 INTER-AGENCY PIPELINE APPROVALS PROCESS (LODGEMENT STAGE)



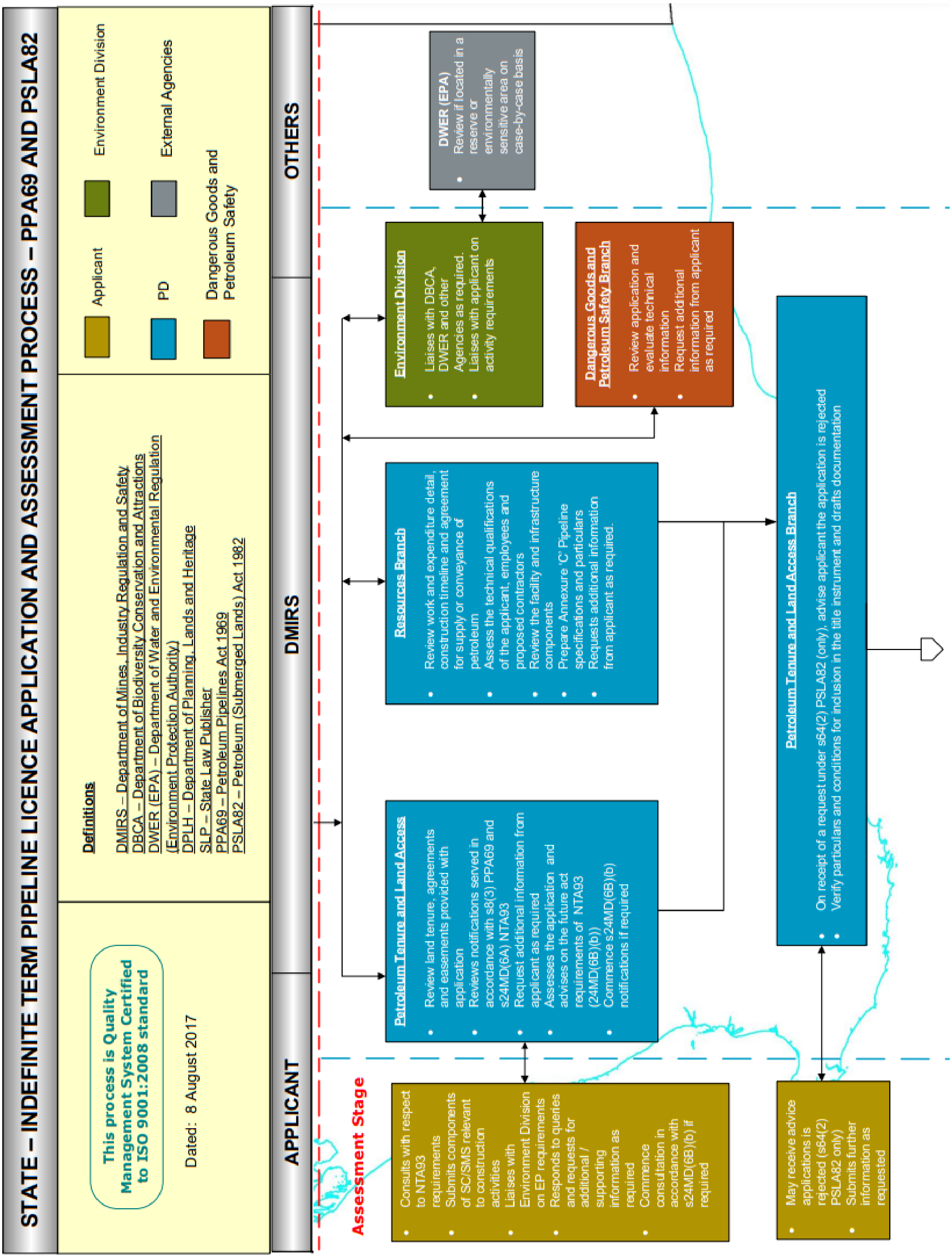
SOURCE: WESTERN AUSTRALIA DEPARTMENT OF MINES & PETROLEUM WEBSITE: HTTP://WWW.DMP.WA.GOV.AU/DOCUMENTS/PETROLEUM/PD-PTLA-OV-010_(WEB).PDF

FIGURE 5.8 INTER-AGENCY PIPELINE APPROVALS PROCESS (SCREENING STAGE)



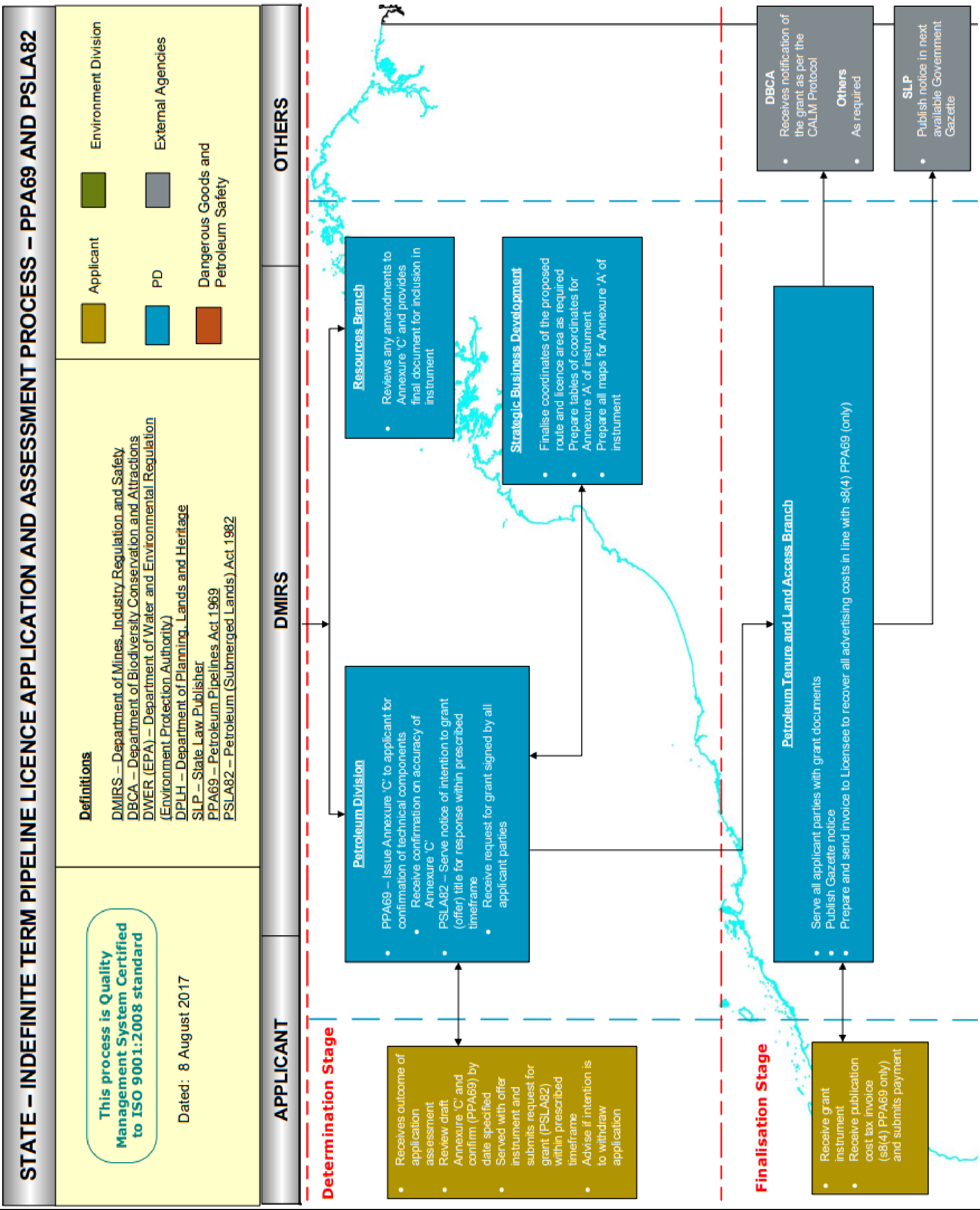
SOURCE: WESTERN AUSTRALIA DEPARTMENT OF MINES & PETROLEUM WEBSITE: HTTP://WWW.DMP.WA.GOV.AU/DOCUMENTS/PETROLEUM/PD-PTLA-OV-010_(WEB).PDF

FIGURE 5.9 INTER-AGENCY PIPELINE APPROVALS PROCESS (ASSESSMENT STAGE)



SOURCE: WESTERN AUSTRALIA DEPARTMENT OF MINES & PETROLEUM WEBSITE: HTTP://WWW.DMP.WA.GOV.AU/DOCUMENTS/PETROLEUM/PD-PTLA-OV-010_(WEB).PDF

FIGURE 5.10 INTER-AGENCY PIPELINE APPROVALS PROCESS (DETERMINATION AND FINALISATION STAGES)



SOURCE: WESTERN AUSTRALIA DEPARTMENT OF MINES & PETROLEUM WEBSITE: HTTP://WWW.DMP.WA.GOV.AU/DOCUMENTS/PETROLEUM/PD-PTLA-OV-010_(WEB).PDF

Implications for schedule

Obtaining access for surveys and preliminary activities, and then acquiring titles to the land required for the submission of a pipeline application could take up to two years. The identification of land to be used for the project therefore needs to commence early.

The issuing of a licence could take up to 12 months from submission of an application and can only occur once all required approvals (environment and native title) have been received.

Land access and tenure

Tenure over the pipeline route is a pre-condition for the issuing of a pipeline licence. Easements are frequently used to provide certainty to both the land user and the asset owner. An easement, once a pipeline is in place, ensures that the land can be used for its previous purposes, subject only to restrictions on use related to pipeline safety requirements. The proponent would need to work through the processes under the LA Act in order to obtain easements over Crown land (essentially all land other than freehold land). Arrangements on freehold land would be negotiated directly by the proponent with the holder of the freehold title.

An authorisation to access to land prior to the issuing of the Pipeline Licence may be provided to the proponent under Section 7 of the PP Act so that surveys and preliminary activities can be carried out. However, this section is not often used; pipeline proponents usually obtain access through negotiation with the landowner (as defined in the PP Act and including Crown land and land vested in a public authority).

WA Government facilitation

The West–East Pipeline Project would be likely to be regarded as a 'significant project' by the Western Australian government because of its potential implications for regional development, State revenue and employment. As such, the proponent would be likely to receive support from the Western Australian Department of Jobs, Tourism, Science and Innovation (DJTSI) to navigate the approvals process and streamline approvals where possible.

To further facilitate the project, the Department may consider forming an overall Government Agency Steering Committee to manage cross-jurisdictional matters.

State Agreement

The West–East Pipeline Project would require a substantial capital investment by the pipeline proponent as well as access to State-owned resources. For both parties, long term certainty and support for outcomes are likely to be desirable. In these circumstances, the WA government may consider whether a State Agreement is warranted. In the past, such agreements have been used to set out the key terms and conditions, rights and obligations of the parties. A State Agreement would provide a highly visible sign of the State's support for and commitment to the project. Relevant examples of previous State Agreements include the *Dampier to Bunbury Natural Gas Pipeline Act 1997*, the *Goldfields Gas Pipeline Agreement Act 1994* and the *Natural Gas (Canning Basin Joint Venture) Agreement Act 2013.*

5.3.4 South Australia

In South Australia, the construction and operation of transmission pipelines and associated facilities are regulated by the *Petroleum and Geothermal Energy Act 2000* and Regulations (PGE Act). The legislation is the responsibility of the Minister for Mineral Resources and Energy and is administered by the Energy and Resources Division (ERD) of the Department of Premier and Cabinet.

The PGE Act requires the design, manufacture, construction, operation, maintenance and testing of pipelines to be carried out in accordance with the relevant requirements of Australian Standard AS 2885 – Pipelines - Gas and Liquid Petroleum.

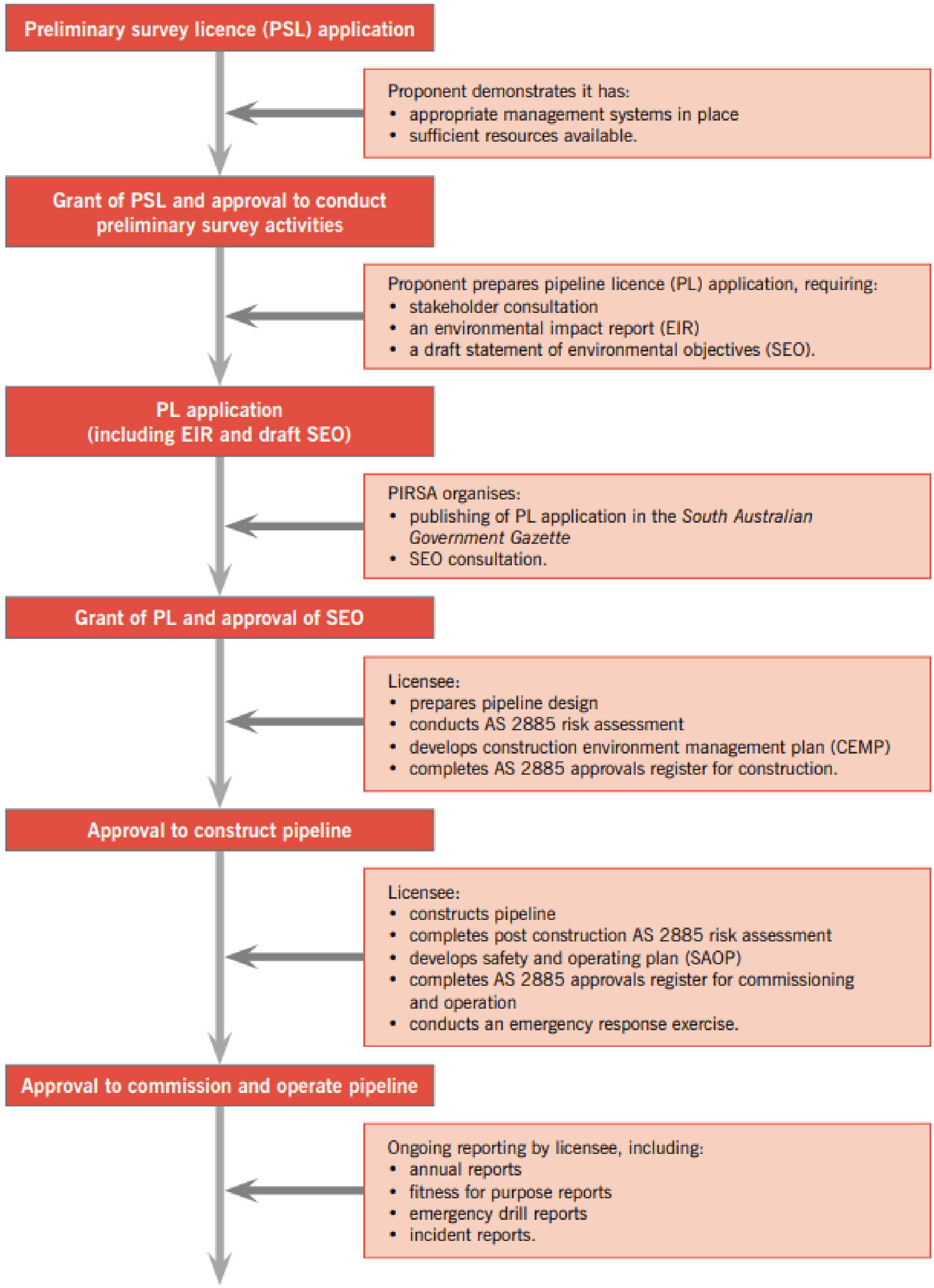
The legislation regulates certain activities which include: preliminary survey activities; construction of a pipeline and operation of a transmission pipeline. There are three key steps to gain approval to undertake these activities:

GHD

— Licence approval – grants rights to access land and undertake certain defined activities.
— Statement of Environment Objectives approvals – requires environmental objectives and appropriate measurement criteria to be set.
— Activity approval – grants approval to undertake pipeline projects based on a demonstration that the licensee has the capability and resources to meet objectives and requirements.

The pipeline approvals process in South Australia is summarised in flowchart form, in **Figure 5.11**.

FIGURE 5.11 PIPELINE APPROVALS PROCESS, SOUTH AUSTRALIA



SOURCE: GUIDELINES FOR PIPELINE LICENSING AND APPROVALS IN SOUTH AUSTRALIA, PRIMARY INDUSTRIES AND RESOURCES SOUTH AUSTRALIA, MARCH 2006, FIGURE 1.

Under SA legislation, any pipeline proponent is required to seek a Preliminary Survey Licence (PSL) to conduct surveys to establish likely routes, and to perform initial geotechnical, ecological and heritage surveys to confirm the suitability of the pipeline alignment. Most preliminary survey activities fall within the scope of the state-wide statement of environmental objectives (SEO).

During this stage landowners are consulted to identify issues and concerns regarding having the pipeline route. Generally, boundary fence lines are followed to minimise impacts. Pipeline proponents are required to compensate landowners for any loss or damage.

Following the PSL, an applicant would undertake a thorough consultation program with all relevant stakeholders. This would then inform the preparation of the Environmental Impact Report and a Statement of Environmental Objectives. These studies form part of the Pipeline Licence (PL) application package for the construction and operation of the transmission pipeline. This information is assessed by the Department to classify the level of environmental significance, using a matrix approach that considers both the predictability and manageability of environmental effects.

The PGE Act is essentially a one-stop-shop for pipeline approvals. However, there can be interactions with other legislation in specific circumstances. Whether or not specific provisions of other South Australian legislation will need to be taken into account for the West–East Pipeline is unlikely to become clear until more is understood about the potential pipeline route. The Department of Premier and Cabinet takes responsibility for dealing with inter-agency consultation and can provide advice at the early stages of project planning.

If the proposed licence area traverses a regional reserve, national park or conservation park, the ERD must consult with the Department of Environment Water and Natural Resources. The consultation period is 15 days and formal approval from the relevant Minister is required before a licence can be issued.

There are other administrative arrangements that help to coordinate requirements under different legislation. There are some interactions between the PGE Act, the *Development Act 1993* and potentially the *Environment Protection Act 1993*. For example, there are specific locations across the State that are listed in Schedule 20 of the Development Regulations that trigger interactions between the two Acts.

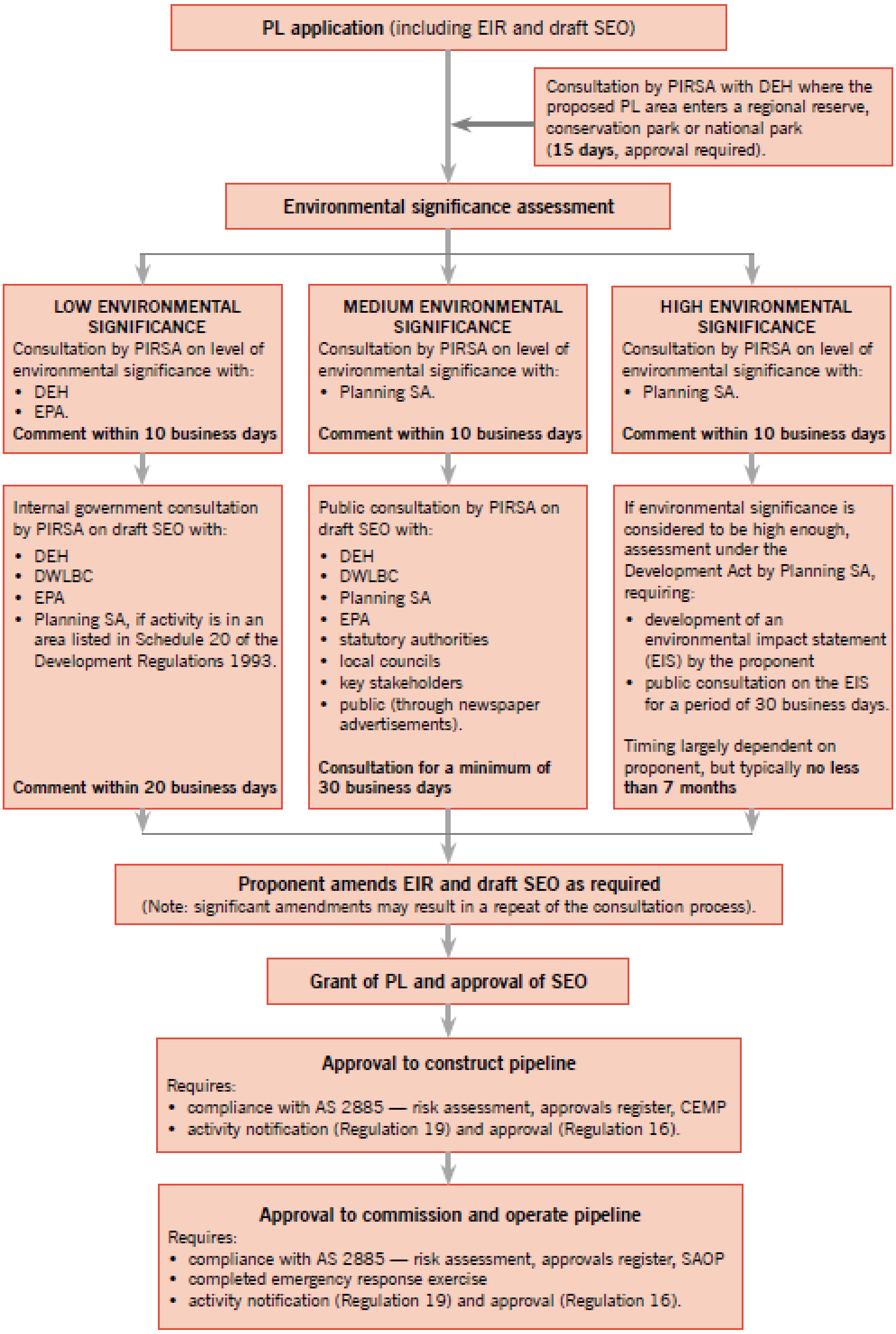
The nature and extent of these interactions depend very much on the route location, proximity of sensitive land uses and whether the route affects certain defined land.

Figure 5.12 provides an indication of the extent of agency interaction and consultation that may be required to construct a pipeline in South Australia.

Land access and tenure

To gain entry to land for the purposes of undertaking regulated activities, the licensee will be required to comply with the access requirements of the PGE Act. Access to land is generally by way of a negotiated agreement. Alternatively, a licensee may choose to seek access to land for construction by way of a notice of entry. Landowners (not lease holders under a pastoral lease) may object to the notice of entry, in which case, mediation between all parties and the Minister is required. If a party refuses to agree to land access (after reasonable attempts to gain agreement have failed), land for the pipeline may be compulsorily acquired under the *Land Acquisition Act 1969*. Formal negotiations for easements required for the construction and operation of the pipeline should commence as soon as possible following granting of the Pipeline Licence, although informal negotiations may commence at prior to licensing.

FIGURE 5.12 AGENCY INTERACTION FOR PIPELINE LICENCE, SOUTH AUSTRALIA



SOURCE: GUIDELINES FOR PIPELINE LICENSING AND APPROVALS IN SOUTH AUSTRALIA, PRIMARY INDUSTRIES AND RESOURCES SOUTH AUSTRALIA, MARCH 2006, FIGURE 1.

5.3.5 Northern Territory

Construction and operation of gas pipelines in the Northern Territory is required to comply with the following legislation:

— *Energy Pipelines Act* and Regulations
— *Environmental Assessment Act*

Energy Pipelines Act

The Energy Pipelines Act (EP Act) provides for the grant of the following authorisations:

— A **Pipeline Permit** which allows the permit holder to enter land for the purpose of determining the route of the proposed pipeline.
— A **Pipeline Licence** which is required for the construction and operation of the pipeline and associated infrastructure.

Pipeline Permit and land access

A pipeline proponent may apply for a permit to enter land for the purpose of determining the route of the proposed pipeline, suitable locations for equipment and the land, if any, needed to provide access to the proposed pipeline and equipment.

The permit application must include certain prescribed information, including details of any agreement entered into, or proposed to be entered into, by the applicant relating to entry onto the land.

The land acquisition programme for a major gas transmission pipeline such as the West–East Pipeline has three phases:

— Access for survey purposes
— Access for construction purposes and
— Tenure for the operation of the pipeline and associated activities.

Most land outside of towns in the NT is either aboriginal or pastoral freehold over which native title rights may exist. A Pipeline Permit is required to enter land for survey and route determination purposes. A permit application must show the details of the agreements entered into with landholders for the survey activities. Negotiation of Indigenous Land Use Agreements (ILUA's) may also be required. Searches and consultation with aboriginal landholders to ensure the protection of sacred sites in accordance with the *Northern Territory Aboriginal Sacred Sites Act (NT) 1978* and *Heritage Act NT* must also be undertaken.

In considering a permit application, the Minister must have regard to certain matters including interference or potential interference with: improvements on the land; flora, fauna and scenic attractions; heritage and geological features. The Minister will also consider effects on registered native title rights or interests and comments of representative Aboriginal or Torres Strait Islander bodies.

Pipeline Licence

Construction of a natural gas pipeline in the Northern Territory requires a Pipeline Licence.

The assessment of a Pipeline Licence application takes into consideration the likely environmental impacts of pipeline construction and operation as assessed under the *Environment Assessment Act*. It also considers the effect that the Licence would have, or would be likely to have, on registered native title rights and interests. Information required in the application includes:

— Full technical and engineering details about the design and construction of the pipeline including the following:
  – the size and capacity of the pipeline
  – what it will carry
  – cathodic measures to protect against corrosion
  – proposed work and expenditure
  – machinery and equipment to be used for construction

- technical qualifications and financial resources available to the applicant.

- A map showing the following:
  - the proposed pipeline route
  - proposed licence area and pipeline corridor
  - location of proposed equipment installations
  - land required for access
  - any aboriginal land and land held by the Commonwealth as well as any easements or land acquired or agreed to be acquired.
- Details of existing or proposed land access agreements.
- The name and address of anyone who could be affected by the pipeline or access requirements, including any agreements or arrangements.
- Proof of technical ability and financial capacity to undertake the project.

Operation of a pipeline requires a Pipeline Management Plan submitted for assessment by the Department and approved by Minister. Land tenure for the pipeline corridor requires Ministerial approval and consent as well as registration once construction is completed.

Environmental Assessment Act

Environmental assessment and approval in the Northern Territory is administered under the *Environmental Assessment Act* (EA Act).

The environmental assessment processes commence with the proponent submitting a Notice of Intent (NOI) to the Northern Territory Environment Protection Authority (NT EPA). This NOI is required to identify where the proposed project has the potential to impact on:

- biodiversity
- air quality (dust)
- soil quality (erosion)
- water resources
- social, cultural and economic impacts
- existing services and infrastructure.

The NOI provides the NT EPA with the information required to decide whether an assessment under the EA Act is required and if so, the appropriate level of assessment. In assessing the NOI, the NT EPA will take into account:

- potentially significant environmental impacts
- the significance and sensitivity of the surrounding biophysical environment
- processes inherent in the proposed action (inputs, outputs and discharges)
- potential on-site or off-site impacts
- requirements for statutory planning, heritage assessments, public health, water resource management, water quality and natural resource management.

If the NT EPA determines that assessment under the EA Act is required, the proponent is required to prepare, depending on the type and complexity of anticipated impacts, either a full Environmental Impact Statement (EIS) or a more limited Public Environmental Review (PER).

For the West–East Pipeline, an EIS could be reasonably anticipated. However, if the pipeline route section lying within the Northern Territory is confined to a relatively small area, and if the number and sensitivity of environmental impacts is expected to be small, the level of assessment may be limited to a PER. The preparation of the EIS or PER would be guided by Terms of Reference prepared by the Northern Territory EPA as shown in Appendix E.

5.4 Pipeline conceptual design

5.4.1 Approach

Key factors that will drive the consideration of alternative pipeline routes include:

— location of existing and potential gas supplies
— geological, environmental and native title issues along potential routes
— possible future mid-line users of natural gas, for example replacement of diesel in mining operations;
— existing infrastructure corridors
— existing infrastructure to support operation and maintenance of the pipeline (roads, airfields, communities, and so forth)
— connection points into the existing east coast gas transmission pipeline system.

As discussed in section 5.2, four main route alternatives were considered:

— Route 1 – Near Karratha to Moomba
— Route 2 – Near Karratha to Adelaide
— Route 3 – Near Broome to Moomba
— Route 4 – Near Broome to Adelaide

The initial approach to pipeline design was to consider the four potential route options commencing near either Dampier or Broome and terminating at either Moomba or Adelaide. Incremental development options taking into consideration upgrading of existing gas pipelines were not considered.

Based on a comparison of modelled rates of market penetration as well as stakeholder feedback, Route 1 was identified as being currently the most prospective route. Detailed assessment was therefore confined to that route. The overall commercial metrics for the other route options are likely to be broadly similar, but somewhat inferior, to those for Route 1.

The balance of this section presents the results of investigations into expected capital and operating cost of the West–East Pipeline assuming construction via Route 1.

5.4.2 Design considerations

The selected pipeline conceptual design was achieved by determining the diameter of pipeline and number of compressor stations required to transport the nominated volume of gas (up to 600 TJ/d) from the nominated inlet point (Dampier) to the delivery point (Moomba). Nominal pipeline diameters ranging from 24 inches to 36 inches were considered.

Key parameters used in determining the concept design include:

— Capacity = 600 TJ per day (~200 PJ/a)
— Pipeline MAOP = 15,020 kPag
— Supply point inlet pressure = 15,000 kPag
— Delivery point outlet pressure = 7,240 kPag
— Compressor station suction pressure = 9,500 kPag
— Compressor station outlet pressure = 15,000 kPag
— Nominal compression ratio = 1.58.

A key assumption for the conceptual design was that pipeline quality natural gas will be provided to the inlet of the pipeline at the supply point inlet pressure (no inlet compression allowed for). The delivery point outlet pressure has been assumed to be 7,240kPag minimum. This would enable the gas to be delivered into most of the east coast gas transmission pipelines at an appropriate pressure, without end-line compression. If a higher pressure is required (for example, for delivery into the South West Queensland Pipeline system) this could be achieved either by utilising existing compression facilities at Moomba or by the installation of additional end-of-line facilities sized to the appropriate volume. This should be reviewed further in any further feasibility studies on the pipeline.

Pressure drop calculations for various pipe diameters were performed to determine the free flow distance between compression stations. The pressure drop calculations were based on internally epoxy coated API 5L Grade X80 carbon steel pipe.

The results of these calculations are shown in **Table 5.3**.

TABLE 5.3 COMPRESSOR STATIONS REQUIRED FOR THE VARIOUS PIPELINE DIAMETERS

Karratha to Moomba 2,600 km					
Diameter (inches)	Section Length (km)	Inlet P (MPa)	Outlet P (MPa)	Compressor Stations	Comp Ratio
36	2900	15	8.91	0	0.00
32	1450	15	9.74	1	1.54
30	967	15	10.18	2	1.47
28	725	15	9.91	3	1.51
26	484	15	10.04	5	1.49
24	363	15	9.44	7	1.59

SOURCE: GHD ANALYSIS

As shown in **Table 5.3**, the number of compressor stations is directly related to the pipeline diameter and pressure profile. Larger pipe diameters result in fewer compressor stations for a given pressure profile. Fewer compressor stations result in lower fuel gas requirements and lower operating costs.

Each compressor station was assumed to include the following components:

— two gas turbine compressor sets operating in a parallel configuration
— compressor discharge coolers and ancillaries
— gas metering
— pig launching and receiving facilities
— Scada and telecommunications for remote monitoring and operation
— buildings and other site facilities.

The conceptual design includes pipeline scraper stations with remote operated emergency isolation valves at approximately 150 km spacing and remotely operated main line valves (MLV) located approximately midway between scraper stations.

5.4.3 Matters for further consideration

When further refining alternative pipeline routes and design concept the following points should be considered:

— pipeline demand profile informed by capacity requirements of prospective customers
— delivery point pressure requirement
— location of possible future intermediate offtakes and inlet points
— spacing and location of scraper stations, main line valves and compressor stations
— compressor station configuration – size, type and number of compressor units
— supporting infrastructure for maintenance access and operations.

6 COST ESTIMATION

6.1 Capital cost estimates

6.1.1 Approach

Capital costs for the pipeline routes have been estimated based on a 'dollars per kilometre per inch diameter' ($/km-in) benchmark basis for the construction of the pipeline, plus compressor station costs on a 'dollars per megawatt' basis. In determining an appropriate figure for this pre-feasibility study, GHD obtained input during the consultation phase from pipeline industry participants and other stakeholders on appropriate construction costs. GHD also consulted with pipeline constructors with recent relevant experience in remote area pipeline construction in Australia, as well as engaging a quantity surveyor to conduct a desktop bottom-up cost estimate for the pipeline. The cost range established through this process was $60,000 per km per inch to $80,000 per km per inch.

GHD selected $70,000/km-in for the purpose of this study as the mid-point of the range.

Compression capital costs of $13,000,000/MW were likewise confirmed during consultation process and desktop review by the quantity surveyor.

The following table sets out the estimated capital cost for different designs along with the required fuel gas (based on running at full capacity)

TABLE 6.1 ESTIMATED CAPITAL COST FOR VARIOUS PIPELINE DIAMETERS — PIPELINE ROUTE 1 (KARRATHA TO MOOMBA; 2,900 KM)

Pipe Diameter (inches)	Pipeline Cost ($ millions)	Compressor Cost ($ millions)	Total Cost ($ millions)	Fuel Gas (% of Throughput)
36	$ 7,308	$ 0	$ 7,308	0.00
32	$ 6,496	$ 108	$ 6,604	1.22
30	$ 6,090	$ 215	$ 6,305	2.43
28	$ 5,684	$ 323	$ 6,007	3.65
26	$ 5,278	$ 550	$ 5,828	6.08
24	$ 4,872	$ 753	$ 5,625	8.51

SOURCE: GHD ANALYSIS

Based on the results shown in **Table 6.1**, the 26-inch case was selected for further analysis because it provides the lowest whole-of-life cost, taking into consideration both the upfront capital cost and on-going cost of fuel gas.

6.2 Operating and maintenance cost estimates

6.2.1 Approach

Operating and maintenance costs were established based on industry norms and compared to actual operating costs for large diameter cross-country pipelines in Australia. For the purposes of this pre-feasibility study, these operating costs have been estimated to be:

— Pipeline operating and maintenance cost: 1.25% of pipeline capital cost

— Compressor station operating and maintenance cost: 5% of compressor capital cost. This excludes cost of fuel gas.

Annual operating and maintenance cost estimates for the 26-inch pipeline case with 5 compressor stations is as follows:

TABLE 6.2 ESTIMATED OPERATING COST (EXCLUDING FUEL COSTS): ROUTE 1, 26-INCH DIAMETER, 5 COMPRESSOR STATIONS

Operating Cost Category	Annual operating cost ($million)
Salary & Wages	$ 39
Asset Opex	$ 38
Administration	$ 13
IT, communications	$ 4
Total	**$ 94**

SOURCE: GHD ANALYSIS

Fuel gas usage is based on an annual load factor of 80 per cent, assuming a seasonal profile of 100 per cent capacity utilisation in the colder months and 60 per cent capacity utilisation in the warmer months. This results in an annual fuel usage of approximately 4 per cent of annual throughput. Assuming a fuel gas commodity cost of $5/GJ and annual throughput of 175 PJ (600 x 0.365 x 80%), this implies an annual compressor fuel cost of about $35 million.

On this basis, the estimated total annual operating, maintenance and fuel costs for the West–East Pipeline, following Route 1 (Karratha – Moomba), with a length of 2,900 km, diameter of 26 inches and 5 compressor stations, is as follows:

— Operating and maintenance costs: $94 million per year

— Fuel costs: $35 million per year

— **Total operating, maintenance & fuel costs: $129 million per year**

6.3 Project schedule

6.3.1 Project Phase and Indicative Timetable

This pre-feasibility study is the first phase in the overall development of this potential pipeline. **Table 6.3** sets out the key scope and indicative timetable for the subsequent phases.

As shown in **Table 6.3**, the estimated period required to complete feasibility studies and other activities required to reach a final investment decision is approximately 2 years.

The project execution phase, which includes obtaining of all necessary approvals and agreements as well as detailed engineering and design, procurement, construction and commissioning could be expected to take a further 4 to 5 years.

The pipeline system would be expected to have a physical operating life of at least 20 years for compressors and more than 50 years for the pipeline itself. However, commercial assessment would most likely be based around a 20-year operating life assumption. This reflects the fact that amortisation of capital expenditure over a shorter period of, say, 10 to 15 years would be likely to require unsustainably high pipeline tariffs, but that much longer life assumptions (greater than 20 years) would be likely to involve a great deal of uncertainty regarding both gas supply and gas demand, leading to unacceptable levels of commercial risk.

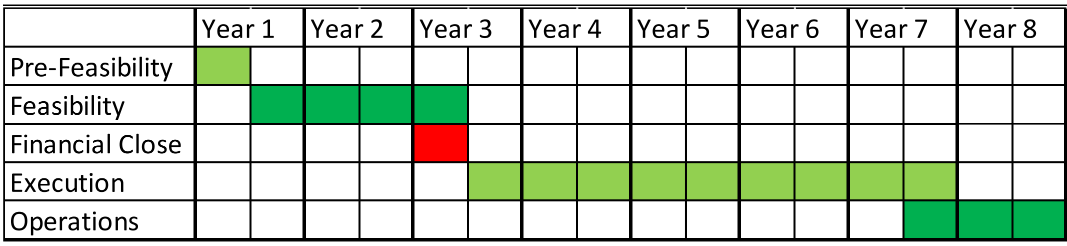
These timetable estimates are indicative only and any actual development timetable would be driven by market/customer demand as well as the appetite of the pipeline proponents and other key stakeholders to progress through the phases.

TABLE 6.3 WEST–EAST PIPELINE PROJECT PHASES AND TIMING

Stage	Pre-feasibility (Current Phase)	Feasibility	Project execution	Operations
Duration	6 months	2 years	4-5 years	20 years
Description	– Stakeholder consultation – High level route selection – Indicative capex and opex estimates – Market modelling	– Stakeholder consultation – Front End Engineering & Design (FEED) – Detailed route selection – Early engagement of land access and approvals – Geotechnical studies – Key financial metrics (IRR) – Tariff model – Binding commercial contracts with off-takers and interconnection parties (conditional on project financing and approvals) – Binding provision of equity and debt (conditional on project approvals) – Funding to commence execution phase	– Approvals – Design – Procurement – Construction – Commissioning	– Ongoing operation and maintenance

Figure 6.1 provides an indicative timetable for completion of the project. This represents the minimum timeframe likely to be required to complete the project. On this basis, a full feasibility study started in early 2018 could allow a West-East Pipeline to come into operation, at the earliest, by early 2024.

FIGURE 6.1 INDICATIVE TIMETABLE FOR SEQUENTIAL PROJECT PHASES



6.3.2 Construction phase

During consultations for this pre-feasibility study, we were told by industry participants that typically 1,000 km of gas pipeline could be constructed in remote areas of Australia in 16 to 18 months using two 'spreads' of equipment and crew.[15] Therefore, by utilising four spreads a 2,900 km pipeline could be constructed in around 22 to 26 months. This estimate may be subject to weather windows, with adverse weather (in particular, abnormally wet conditions) having the potential to cause significant

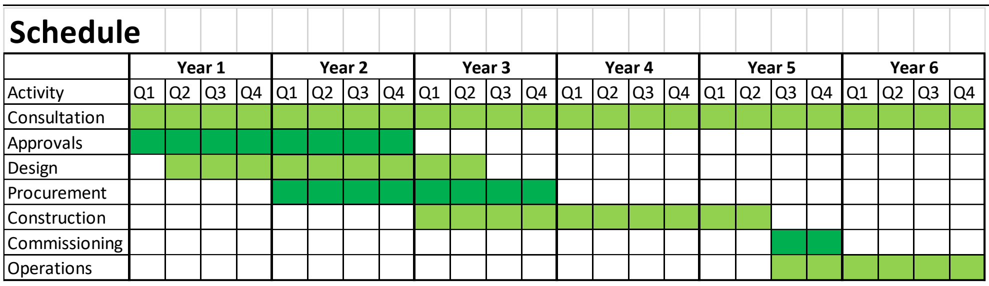
[15] Pipeline construction is typically carried out in a defined sequence with workers and equipment, in composite crews, working in a moving assembly line fashion. These equipment and personnel crews are commonly referred to in the pipeline industry as 'spreads'.

delays in pipeline construction because of the resultant difficulties in moving materials, equipment and personnel along the pipeline route.

Labour requirements for a four-spread construction program are expected to average around 900 personnel, with a maximum of approximately 1,300 workers. A project requiring four construction spreads is likely to challenge the resources of many Australian-based constructors in terms of plant, equipment and labour. It is therefore likely that two construction companies would be required to complete this project in the specified timeframe.

An indicative schedule for the design and construction of the pipeline is shown in **Figure 6.2**. This shows a five-year timeframe from financial close to first gas delivery. The schedule anticipates that key activities such as a front-end engineering and design (FEED), commercial contracts and financing activities would be completed as part of a detailed feasibility study prior to commencement.

FIGURE 6.2 INDICATIVE CONSTRUCTION SCHEDULE



SOURCE: GHD ANALYSIS

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7 PRELIMINARY RISK EVALUATION

7.1 Introduction and context of risk evaluation

Over the course of the pre-feasibility study, a number of areas were identified which present risks to the successful delivery of the project. The aim of the preliminary risk evaluation was to identify the key risk issues and to categorise them for consideration in subsequent phases of the project.

A project risk is one that would prevent the successful delivery of the objectives of the project. In this context, the project objectives are defined as follows:

— Develop an optimised pipeline (size, route, capex and opex) to deliver Western Australian gas to Eastern Australia at market competitive prices, with sufficient gas volumes to meet customer requirements, and having the overall effect of reducing domestic gas prices and improving security of supply in Eastern Australian markets.

— Identify the barriers (technical, market, commercial, regulatory) that may inhibit the development of the pipeline, and consider how those barriers could be reduced or eliminated.

— Identify the approvals and consents required by local, state and federal governments.

— Identify the Australian Standards to be used for the design, construction, operation, maintenance and decommissioning of the pipeline, including all pipeline safety management aspects.

The Project Risk Register is the key output of the project risk evaluation. This register will provide a valuable resource should the project proceed further.

7.2 Risk evaluation approach

The evaluation of project risks was undertaken using a qualitative risk assessment approach consistent with ISO 31000:2009[16] and involved the following steps:

— define logical areas to assess project risks (break project into component parts including market, geographic, pipeline infrastructure)

— confirm risk approach using relevant risk criteria

— pre-populate the risk register and undertake an independently facilitated risk assessment workshop with key stakeholders

— compile results for analysis

— summarise methodology and outcomes in a report.

Potential risks associated with the project were identified, along with the likelihood and consequence for each identified risk. The key risk categories used for the risk evaluation were:

[16] Standards Australia, ISO 31000:2009 'Risk Management – Principles and Guidelines'

- routing
- design, construction & delivery
- approvals
- economics
- commercial and market.

The risk evaluation included an initial rating of each risk (in the absence of mitigation strategies), proposed risk mitigation strategies, and rating of the residual risk.

The risk evaluation criteria were selected to be appropriate for a project at the pre-feasibility assessment stage. The consequence evaluation criteria chosen for the assessment are listed in **Table 7.1**.

TABLE 7.1 CONSEQUENCE EVALUATION CRITERIA

Consequence evaluation criterion	Impact
Safety	Impact on public safety
Financial	CAPEX OPEX REVENUE
Project Schedule	Impact on project delivery
Reputation / Political	Impact on principal organisation
Legal / Contractual	Impact on principal organisation
Engineering / Technical	Impact on project delivery
Community / Stakeholder	Impact on principal organisation
Environment / Heritage	Impact on external environment

SOURCE: GHD ANALYSIS

A full description of the risk evaluation criteria is provided in Appendix F.

7.3 Risk register

A risk register was prepared following a series of workshops to identify and analyse the key risk issues and to categorise them for subsequent phases of the project. The risk register is provided in Appendix F. The risk issues identified and analysed are summarised in **Table 7.2**

TABLE 7.2 RISK ISSUES SUMMARY

Risk Category	No. of Issues raised	Residual Risk Level			Opportunities identified
		High	Medium	Low	
Routing	4	Nil	2	2	1
Design, construction & delivery	7	Nil	Nil	7	Nil
Approvals	8	Nil	4	4	Nil
Economics	7	Nil	Nil	7	1
Commercial & Market	10	Nil	1	9	Nil
TOTAL	36	Nil	7	29	2

SOURCE: GHD ANALYSIS

7.4 Risk evaluation

The key technical, economic, marketing and commercial risk issues raised during the workshops are discussed in the following sections.

7.4.1 Technical issues

Routing

The identified risk is that the options selection process identifies an unsuitable route for the pipeline. In the worst case this may lead to loss of market opportunities for gas sales causing the project to become unviable.

Design, construction and delivery

The identified risk is that the construction contractor fails to complete the construction contract, causing construction delays, termination of the contract, and resumption with a new construction contractor. In the worst case this may cause lead to a >30% capital cost exceedance and a >12-month delay, with the loss of gas sales and potential reputational damage to the proponent.

Construction of the pipeline in difficult terrain and seasonal conditions is likely to occur and to cause cost overruns and project delays.

Approvals

Multi-jurisdictional development approvals are required for the project to proceed, but there is a risk that not all can be obtained. There are numerous approvals required for this project with each state and territory having its own approaches to the approvals process. This makes the cross-jurisdictional approach challenging, particularly in addressing the federal approvals (*EPBC Act* and *Native Title Act*).

New Native Title claims may jeopardise the project approval timeline. There is a lack of clarity on the sections of the Act that may apply to this project, which may require legal advice. This may result in significant time delays.

Given the above complexities, there is a risk that the timeframe for regulatory approvals exceeds the proposed two years due to poor scoping of work and scopes of work for field investigations. In the worst case this may lead to loss of market opportunities for gas sales causing the project to become unviable.

Economics

Lack of robustness in project costing could result in the pipeline owner committing to tariffs that are too low to provide an adequate return. In the worst case, the revised costing would make the project economically non-viable with the result that the project does not proceed, causing reputational damage to the proponent.

Sourcing of pipeline materials and compressors is subject to international currency exchange rates, whereas pipeline revenues will most likely be in Australian dollars. Adverse currency movements could increase effective costs of construction (in Australian dollar terms). Consequences could be similar to under-estimation of project costs or cost over-runs during construction.

New pipeline regulations may discourage investors. Pipeline owners have expressed concern that recent changes to the *National Gas Rules* will discourage shippers from entering into long-term firm capacity contracts. In the worst case this may lead to the project becoming non-viable.

Marketing and commercial issues

To keep delivered cost of gas competitive, the pipeline will need to deliver large volumes of gas—potentially around one-third of total eastern Australia domestic demand. Insufficient market demand would undermine project economics by driving up the required pipeline tariff, potentially making the delivered cost of gas uncompetitive.

There are several potential new sources of gas supply that would be closer to the main Eastern Australia demand centres and therefore have lower transport costs incurred in accessing those markets. These include new conventional gas fields both onshore and offshore (Bass Strait); CSG in NSW and Victoria; unconventional (tight gas, shale gas, basin-centred gas) in South Australia and the

Northern Territory), as well as LNG imports. Any or all of these new supply sources could emerge to challenge the pipeline's market opportunity.

There is a risk that there will be insufficient gas buyers willing to commit to long term gas purchase contracts, or that gas producers will be unwilling to commit sufficient gas reserves and production capacity, over a sufficient period, to underpin the project.

The various commercial, market and regulatory risks set out above, when taken together, may result in an overall risk profile that equity investors and debt providers are unwilling to support, leading to a failure to secure project financing.

Risk mitigation and residual risks

Known existing risk mitigations and recommendations for additional mitigations were considered for each of the risk issues raised to determine the residual risk to the project. As shown in **Table 7.2**, the analysis concluded that it would be possible to mitigate all risks to a residual rating of 'Moderate' or 'Low'. Since there are no residual risks rated as 'High' it has been established that the project would be viable from a risk perspective, and that all the key technical, economic, marketing and commercial risk issues raised during the workshops would be manageable.

Key risk mitigations are described in Table 7.3.

TABLE 7.3 KEY RISK MITIGATIONS

Risk Category	Known existing mitigations	Recommended additional mitigations
Routing	Stakeholder negotiations to proceed prior to selecting final route to identify any constraints and to identify alternative routes that are less constrained.	Undertake field aerial survey to identify areas of concern w.r.t. pipeline construction and operation. Include alternative routes. Undertake parallel negotiations for alternative routes based on InDeGO analysis using different parameters - e.g. mine tenements seen as only slightly constrained.
Design, construction & delivery	Contract tender process to include an expression of interest / prequalification / shortlisting phase to ensure only qualified contractors are invited to bid.	Seek commercial protections under the contract to insure against a contractual failure. Consider novating design contract to construction contractor so the contractor has control of the design schedule and can adapt construction schedule to suit. Use a third party for validation of the pipeline design
Approvals	Early and constant engagement with all parties (Commonwealth and State), consistency of approach between core project teams within the parties. Early and constant engagement with stakeholders including the DOEE, regulators, landowners and the community. Provide clear scope of work to field teams.	Establish a steering committee across the jurisdictions to coordinate the Approvals process across the respective jurisdictions in the context that this is a major project.
Economics	Cost estimates will be refined over time through feasibility studies and design processes that are well understood. Secure sufficient gas buyer commitments prior to FID.	Seek and gain appropriate relief from provisions of the National Gas Rules that may otherwise prevent securing sufficient shipper commitments.

Risk Category	Known existing mitigations	Recommended additional mitigations
Commercial & market	No commitment to project until market demand shows justification. Selection of low cost activities to undertake to position for advancement of project on a just in time basis. Identification of critical points where decisions must be taken to advance the project for gas to be available when market demand exists. Secure gas supplier commitments to put together a commercial case to put to the market. Secure sufficient gas buyer commitments prior to FID. Secure sufficient commercial commitments to derisk the project enabling FID.	Government to keep this option and alternative developments under surveillance, and review on a regular basis the status of other gas supply options.

7.5 Opportunities

In addition to the risks identified, key opportunities are provided by this project.

The presence of a new large source of gas supply, with access to a substantial volume of line pack providing short-term offtake flexibility, would substantially improve energy security in the Eastern Australia by increasing the options available to gas consumes to meet both base load energy and peak seasonal demand requirements.

The potential introduction of a new, large-scale source of gas supply would increase competitive tension in the market, helping to maintain pricing discipline and putting downward pressure on prices.

The may also be opportunities to provide other intermediate gas supply offtakes along the route identified. This would not only enhance the economics of the project but could also improve the prospects for development of otherwise stranded mineral and energy resources.

7.6 Summary findings

The technical risks associated with this project—routing, approvals, design, construction and delivery—can be largely mitigated using conventional project management strategies that are well established and proven. These are not seen as a barrier to the project proceeding.

The commercial and market risks present major challenges. For the project to proceed, it would be necessary to secure sufficient long-term commitment on the part of both gas producers and gas buyers to de-risk the project and make it financeable. This alignment of sellers and buyers would need to be achieved in an environment of considerable market uncertainty that is not generally conducive to entering into long-term contractual commitments. Achieving the necessary buy-in will also need to occur despite the potential emergence of new competitive sources of gas which are closer to the Eastern Australian market and could present buyers with more compelling alternatives.

If the commercial and market challenges outlined above can be overcome, construction of the project could deliver significant security of supply benefits to the Eastern Australian market. It could provide regional development opportunities by helping to unlock otherwise stranded mineral and energy resources located near the pipeline route. Such opportunities should be further investigated in the course of any future feasibility studies.

The market analysis presented in Chapter 4 demonstrates that while the West–East Pipeline could eventually the achieve the levels of penetration of the Eastern Australian gas market required to make the project commercially viable, that is unlikely to occur for at least ten years. In the meantime, other competitive supply alternatives may emerge that would further delay or eliminate the market opportunity for the West–East Pipeline. Therefore, rather than making any costly pre-emptive commitments, the Government should keep the various options under surveillance, and should take whatever prudent, low-cost steps it can to maintain the West–East Pipeline as a viable option to meet any future severe and sustained gas supply shortage in Eastern Australia. Major financial commitments to the project should only be made if and when it emerges that the West–East Pipeline is likely to provide the best, least-cost way of meeting the long-term needs of gas users and improving energy security in Eastern Australia.

8 COST–BENEFIT ANALYSIS

This chapter describes the methodology and results of the economic Cost Benefit Analysis (CBA) conducted for the preferred route option (Route 1) developed for the West–East Pipeline pre-feasibility study. It is an assessment of the economic costs and benefits to the Australian east coast gas customers, west coast gas producers and the pipeline developer and operator, as a result of the project.

Investment in pipeline infrastructure can affect the economy in various ways. Such an investment can create employment during the construction and operation phases of the pipeline. By providing access to more competitively-priced gas sources, east coast gas users may experience lower prices. New pipeline infrastructure can also act as a catalyst to the development of on-shore and off-shore gas resources that weren't previously accessible and can help to open up mineral resources that previously lacked access to energy supply.

To inform the possible future course of gas shortages in east coast, a Base Case (no West–East Pipeline) and a 'with pipeline' Route 1 option were developed in this chapter to consider a wide range of possible economic outcomes. Underlying the Route 1 option is a level of investment in pipeline infrastructure along the Burrup to Moomba pipeline corridor and additional production in Western Australia which are assumed to generate additional economic activity including the activity associated with construction and maintenance of gas production and pipeline infrastructure.

The analysis presented in this chapter considers who would potentially receive the benefits or incur the costs in developing the West–East Pipeline.

Generally, the direct costs of the gas fields infrastructure, the gas extraction costs and the pipeline development and operational costs will be borne primarily by the commercial investors and operators.

Similarly, the direct monetary benefits will also accrue mostly to the commercial operators of gas production and pipeline facilities. The pipeline could also be expected to deliver a monetary to east coast customers in the form of lower gas prices.

There would also be a range of indirect benefits and costs as a result of the additional gas production and pipeline development. The indirect impacts are considered in the next chapter using computable general equilibrium modelling (CGE). For example, the additional output and employment generated by the pipeline project would have an impact on Gross Domestic Product (GDP). Similarly, governments would benefit from higher tax revenues generated by these additional economic activities. These effects are examined in Chapter 9.

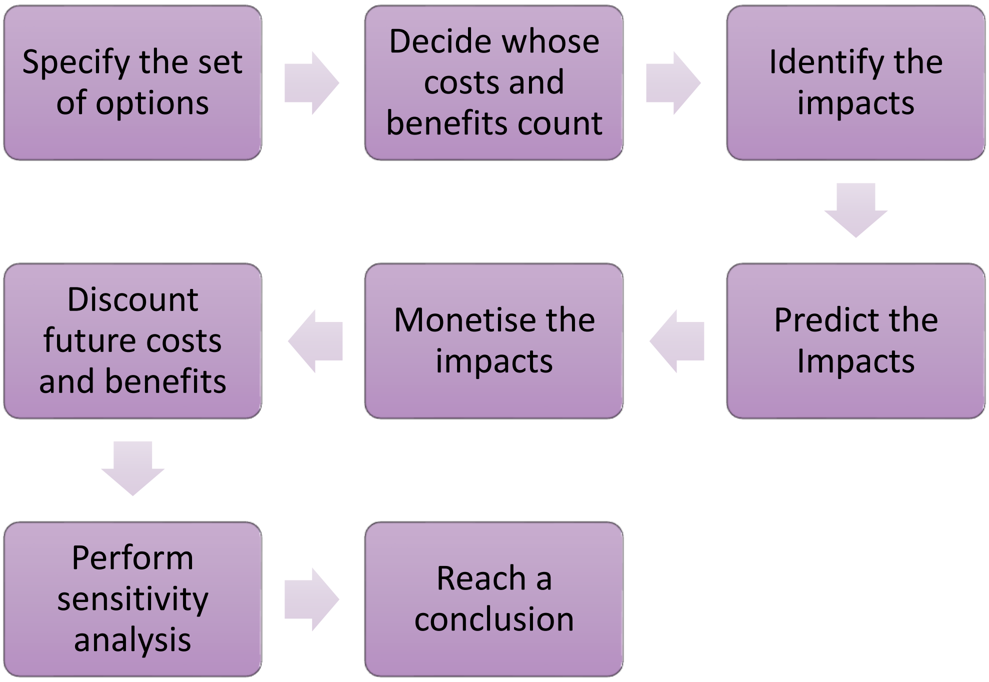
The CBA assesses the economic benefits and costs of the West–East Pipeline if developed following the Route 1 option (Burrup to Moomba) which was identified as the preferred route option through the market modelling (see Chapter 4). The other route options assessed in Chapter 4 are not assessed using CBA; the results would be likely to be directionally similar but inferior to the Route 1 outcomes.

8.1 Assessment methodology

A CBA is an economic approach used to judge the economic merits of a proposed project. The anticipated future flows of costs and benefits of the project are discounted to arrive at a 'present value' for each annual flow. By adding up the present value of the future flows of costs and benefits, a net present value (NPV) is calculated for the project. The NPV is a dollar estimate of how much would be gained, or lost, by going ahead with the proposed project. A positive NPV means the project has economic merit.

The broad approach used for the CBA is provided in **Figure 8.1**. These steps are detailed below.

FIGURE 8.1 KEY STEPS IN CBA APPROACH



SOURCE: ACIL ALLEN CONSULTING BASED COMMONWEALTH OF AUSTRALIA 206, COST-BENEFIT ANALYSIS GUIDANCE NOTE, P. 2.

8.2 Options

The market modelling provided an assessment of a number of route options with variations as described in Chapter 4.

For the CBA, two options are analysed:

— a business-as-usual or Base Case scenario

— the 'with pipeline' Route 1 option scenario

8.2.1 Base Case

The Base Case provides a 'do nothing' or *status quo* scenario without the West–East Pipeline.

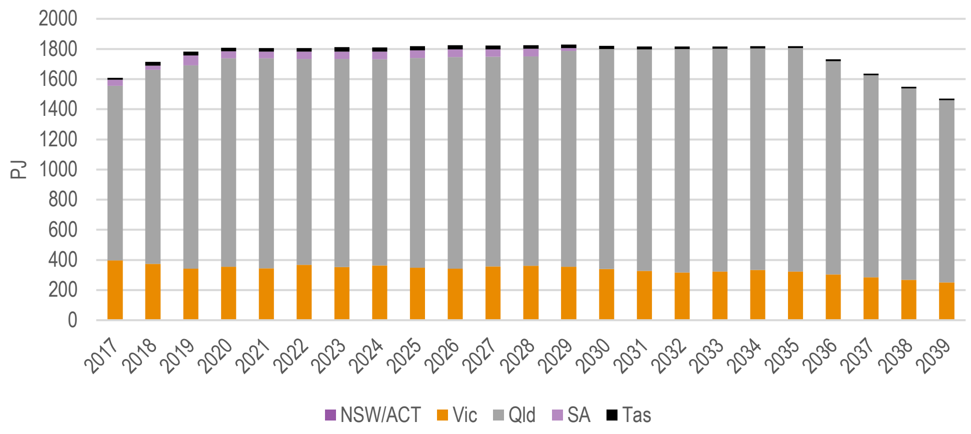
The time frame for both the Base Case and Route 1 options are between 2018 and 2039.

In Chapter 4, ACIL Allen's *GasMark* model was used to estimate the production, consumption and delivered gas prices at various nodes under the Base Case assumptions, and for the various route options analysed.

For example, in the Base Case, the model showed that total east coast gas production will increase to around 1,800 PJ by 2020 and remain at that level until 2035, and that production levels would then decrease to 1,470 PJ by 2039 as shown in **Figure 8.2**.

The decline in east coast gas production levels in the Base Case is mainly due to reduced LNG production in Queensland beyond mid-2030s and depletion of gas fields in Victoria.

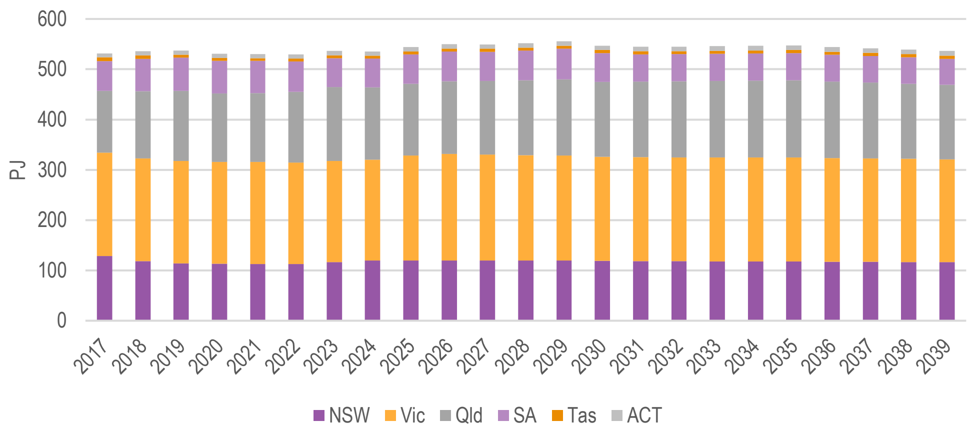
FIGURE 8.2 BASE CASE GAS PRODUCTION IN EAST COAST



SOURCE: ACIL ALLEN GASMARK MODEL

The estimated domestic consumption of gas (excluding the consumption by Queensland LNG plants) on the east coast, by state/territory, for the Base Case is shown in **Figure 8.3**. The annual average consumption of gas in east coast is around 540 PJ.

FIGURE 8.3 BASE CASE DOMESTIC GAS CONSUMPTION IN EAST COAST (EXCLUDING LNG)

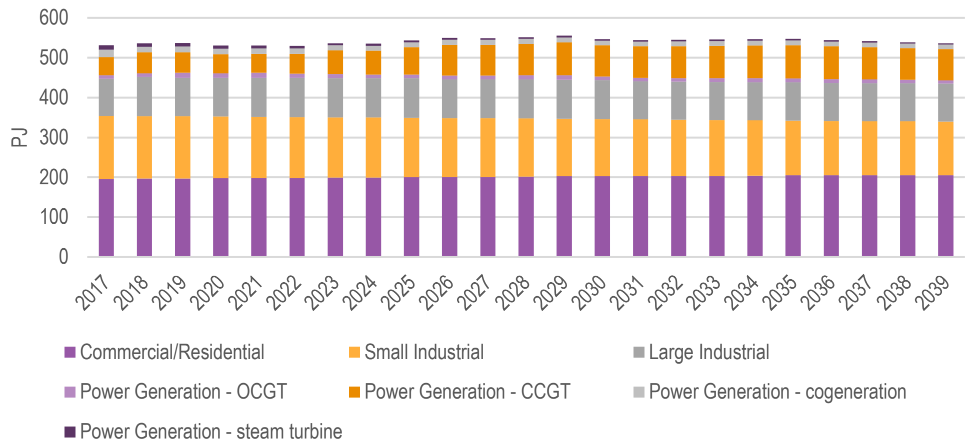


SOURCE: ACIL ALLEN GASMARK MODEL

The corresponding consumption of gas by customer type (again excluding LNG) is illustrated in **Figure 8.4**.

Nearly 40 per cent of demand for gas is from commercial and residential users, followed by small scale and large scale industrial users. Electricity generation — OCGT, CCGT, cogeneration and steam turbine — consumes nearly 20 per cent of gas in East Coast market under the Base Case assumptions.

FIGURE 8.4 BASE CASE DOMESTIC GAS CONSUMPTION IN EASY COAST BY CUSTOMER (EXCLUDING LNG)

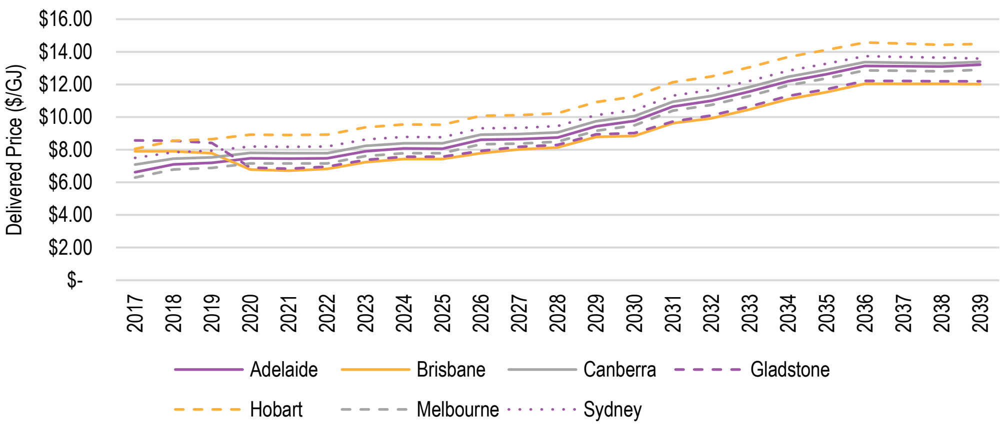


SOURCE: ACIL ALLEN GASMARK *MODEL*

The Base Case delivered gas prices at various locations on the east coast are summarised in **Figure 8.5**. Since all east coast states are part of the NEM, the average annual delivered gas prices are (highly correlated/closely linked/move together) closely move together.

The delivered east coast gas prices would grow in real terms at an annual average rate of around 2.7 per cent between 2018 and 2039 from around A$7.5/GJ in 2018 to $13/GJ in 2039. There are some regional differences in delivered prices reflecting differences in transmission costs and capacity constraints.

FIGURE 8.5 DELIVERED GAS PRICES IN BASE CASE



SOURCE: ACIL ALLEN GASMARK *MODEL*

8.2.2 Pipeline Route 1 Option – Burrup to Moomba

The key features of the proposed West–East Gas Pipeline are provided in **Table 8.1**. The proposed pipeline length is 2,600 kilometres (Route 1 optimised [northern] route) and diameter is 26 inches. It will use 5 compressors and has a daily capacity of 600 TJ.

TABLE 8.1 PIPELINE DESIGN ROUTE 1 OPTION (OPTIMISED) — BURRUP TO MOOMBA

Features	units	data
Pipeline Diameter	(inches)	26
Pipeline length (optimised route)	(km)	2,600
Compressors	(no.)	5
Capacity	(TJ/d)	600
Maximum Throughput	(PJ/a)	219
Load Factor	(%)	80%
Annual Throughput	(PJ/a)	175.2

SOURCE: GHD

Pipeline Route 1 as modelled is shown in **Figure 4.4**; the corresponding optimised pipeline route alignment as determined using multi-criteria analysis (MCA) is shown in **Figure 5.5**.

The Route 1 pipeline links gas fields in the Carnarvon Basin (Dampier area) to the Moomba gas supply hub in central Australia. The Carnarvon Basin, and in particular the Barrow and Dampier Sub-basins, is regarded as the premier hydrocarbon basin in Australia, and is one of the more intensively explored areas of the country. The basin lies mainly offshore, extending north from the Pilbara Craton to the continental–oceanic crust boundary, and covers about 500,000 km^2. The northern part of Carnarvon Basin is transitional to and overlies the predominantly onshore southern Carnarvon Basin. Several islands provide locations for production facilities and operations bases (e.g. Barrow Island, Airlie Island, Varanus Island and Thevenard Island). The onshore part of the northern Carnarvon Basin is readily accessible from the North West Coastal Highway. The towns of Carnarvon, Exmouth, Onslow, Dampier, Karratha and Port Hedland provide support facilities for offshore exploration and production. Karratha is the loading terminal for LNG exports from the North West Shelf and Pluto projects, and a processing centre for supply of gas to domestic markets including Perth, Bunbury and the Eastern Goldfields.[17]

West–East Pipeline Route 1 passes through Western Australia and South Australia, mostly through the native title lands located in the following Statistical Area Level 2 (SA2) regions.

— East Pilbara (WA)
— Leinster – Leonora (WA)
— Petermann – Simpson (NT)
— APY Lands (SA)
— Outback (SA)

8.3 Directly affected parties

The West–East Pipeline will potentially affect the following groups and individuals:

— Gas producers in both Western Australia and Eastern Australia
— Energy consumers in both Western Australia and Eastern Australia
— People affected by the construction and operation of gas production and transportation facilities, including Native Title holders, pastoralists and other groups and individuals with interests in alternative land uses along the pipeline corridor.

Only the direct costs and benefits arising from the project are considered in this Chapter 8. High-level broader economic impacts at state and national levels are considered in the economic impacts chapter (Chapter 9). Potential socio-economic impacts at regional level, and implications for individuals and groups along the pipeline corridor are not assessed in this pre-feasibility study.

As discussed in Chapter 4, there will be several potential suppliers of gas in Western Australia that could supply gas into the proposed pipeline. The benefits and costs of additional gas production to

[17] WA Government

support the West–East Pipeline project is considered, along with the benefits and costs of building and operating the pipeline itself.

As shown in Chapter 4, the supply of gas via the West–East Pipeline results in some displacement of higher marginal cost gas production in Eastern Australia and also acts to increase overall consumption levels in the east coast market. The CBA has considered the costs and benefits of additional production and consumption of gas on the east coast of Australia.

8.4 Identification of impacts and measurement indicators

Establishing the range of impacts to be included is a crucial step in the CBA. The study considers a full range of impacts for Route 1 option, identifying and including the *incremental* costs and benefits relative to the Base Case including:

— how the project may affect and be affected by the market impact of connecting the Western Australian and east coast gas markets, including supply, demand, competition between suppliers, possible reduction in market share of current suppliers, gas prices, gas flows and potential implications for LNG producers

— how the proposal could impact or be impacted by State and Territory government environment approvals or policy

— potential impacts on the project by possible Native Title claims or litigation of State or Federal environmental approvals (including on timing of the delivery of pipeline).

These impacts are monetised and included in the cost benefit analysis.

Key measurement indicators considered in the CBA are:

— Incremental costs and benefits incurred by gas producers and pipeline developers and operators. These costs include capital costs and operational costs

— The gas energy cost savings by customers on the east coast of Australia.

8.4.1 Pipeline development and operation

An indicative schedule for planning and construction of the West–East Pipeline is provided in **Figure 6.1**. It will take around six years to complete the planning and construction of the pipeline from initial consultation to the commencement of operations.

Capital expenditure

West–East Pipeline capital expenditure details by category are provided in **Table 8.2**.

To build a pipeline between Burrup and Moomba via the optimised (2,600 km) route would cost the pipeline developer around A$5,282 million.

Major cost categories are site preparation (24 per cent) and steel line pipe (23 per cent).

The pipe itself would be imported from overseas since there are no manufacturers in Australia currently able to make pipe of the required specification.

Pipeline installation would cost around 14 per cent of total capital expenditure. Preliminaries which include development approvals from governments, native title payments, compensation and so forth constitute around 5 per cent of capital expenditure, most of which will be spent in the first two years.

There will be five compression stations along the route which would cost A$550 million in total. The compressors are also likely to be imported.

Labour costs constitute around 36 per cent of capital expenditure and non-labour or materials costs around 64 per cent of capital expenditure.

TABLE 8.2 PIPELINE CAPEX DETAILS (A$ MILLION)

Cost item	Year 1	Year 2	Year 3	Year 4	Year 5	Total	% of Total
Pipe Supply	0	0	618	618	0	**1,237**	23%
Pipe Delivery	0	0	82	82	0	**164**	3%
Site Preparation	0	0	1,273	0	0	**1,273**	24%
Pipeline Installation	0	0	189	378	189	**757**	14%
Compressor Stations	0	0	220	275	55	**550**	10%
Direct Cost Loading	0	0	131	263	131	**525**	10%
Preliminaries	92	185	0	0	0	**277**	5%
Contractors Margin	0	0	0	0	499	**499**	9%
TOTAL	**92**	**185**	**2,514**	**1,617**	**875**	**5,282**	**100%**

SOURCE: GHD

Operating expenditure

West–East Pipeline operational expenditure details are provided in **Table 8.3**.

To operate the West–East Pipeline, it would cost around A$121.7 million per year which includes a gas cost for operation of compressors of A$35 million. The other operating costs include:

— Wages, salaries and supplementary payments to employees (45 per cent)
— Pipeline opex (materials, parts, supplies, contractors, vehicles, fees) (18 per cent)
— Compressor opex (materials, parts, supplies, contractors, vehicles, fees) (18 per cent)
— Administration, rent and outgoings, insurance, licenses, fees, audit, legal (15 per cent)
— Hardware, software, managed services, network services (5 per cent)

TABLE 8.3 PIPELINE OPEX DETAILS (A$ MILLION) PER ANNUM

Cost item	Cost (A$ million)	% of total non-gas operating cost
Salary & Wages	39.0	45%
Pipeline Opex	15.2	18%
Compressor Opex	15.2	18%
Administration	13.0	15%
IT and communications	4.3	5%
Gas cost	35.0	
TOTAL	**121.7**	

SOURCE: GHD

The gas cost is assumed to be A$5/GJ with around 7 PJ of fuel gas is required annually to operate the compressors resulting in an annual fuel cost of around A$35 million.

The pipeline is assumed to operate between 2022 and 2039 and would cost around A$2,190 million to operate over an 18-year period.

Total estimated pipeline capital and operational expenditure in current prices would be around A$7,472 million.

Pipeline revenue

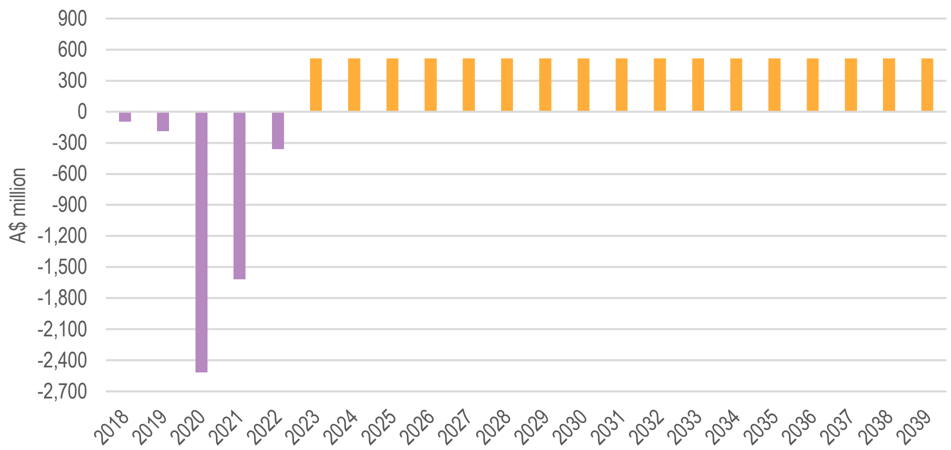
The pipeline receives revenue from the contracted tariff rate on capacity reserved on the West–East Pipeline. The estimated efficient tariff rate for modelling purposes is A$2.91 in current prices.

The estimated annual contracted capacity is 219 PJ.

The estimated annual gross revenue is A$637 million and net revenue after deducting operational expenditure is A$515.6 million. The developer and operator of pipeline would receive a total of nearly A$4 billion undiscounted pre-tax cashflows over an 18-year period.

The pre-tax cashflows of the West–East Pipeline are shown in **Figure 8.6**.

FIGURE 8.6 ESTIMATED PRE-TAX CASHFLOWS OF WEST EAST PIPELINE



Source: ACIL Allen based on GHD data

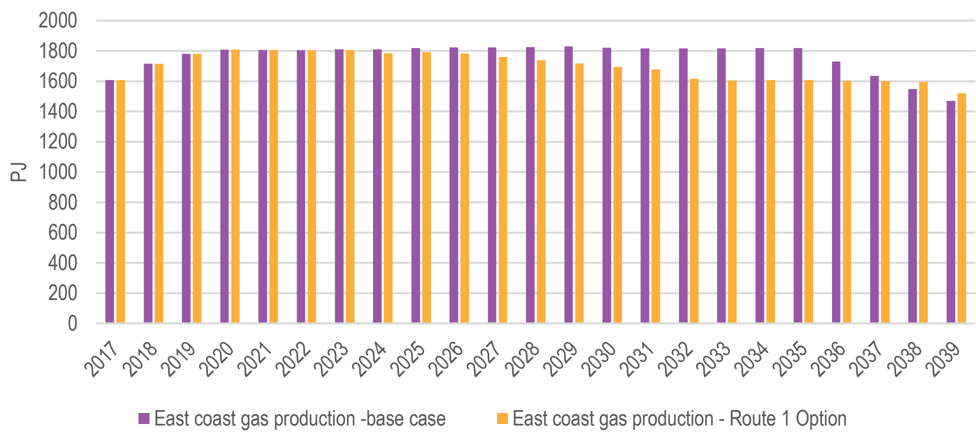
8.5 Predicted impacts on east coast gas market

With the pipeline, east coast gas production, consumption and prices are expected to change compared to the Base Case.

The *GasMark* modelling estimated the production, consumption and delivered gas prices at various market nodes for the West–East Pipeline and the Base Case.

As discussed in Chapter 4, apart from gas produced and consumed by Queensland LNG projects and the gas produced in Victoria and Tasmania, the gas production and consumption levels were not significantly changed in Route 1 scenario relative to the Base Case (**Figure 8.7**). This is because the gas delivered via the West–East Pipeline is projected to replace gas produced from higher cost marginal fields in the east coast gas market.

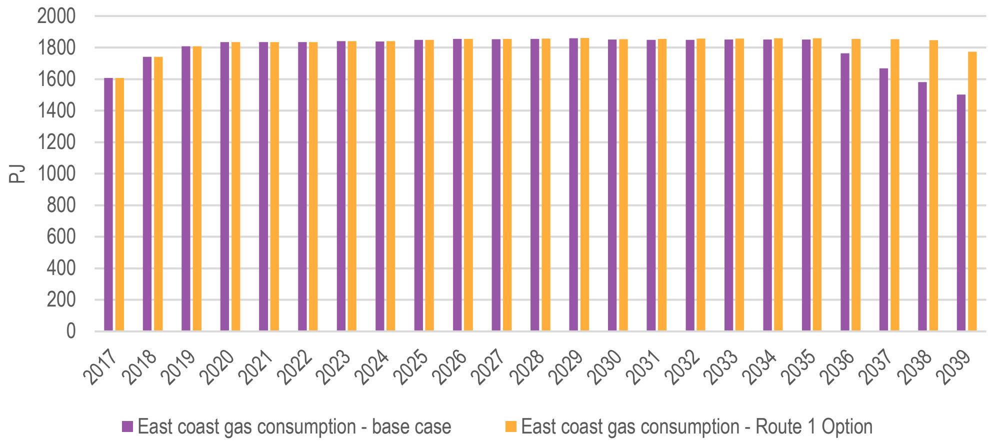
FIGURE 8.7 EAST COAST GAS PRODUCTION (PJ), 2017-2039



SOURCE: ACIL ALLEN'S GASMARK MODEL

East coast gas consumption is provided in **Figure 8.8**.

FIGURE 8.8 EAST COAST GAS CONSUMPTION (PJ), 2017-2039: BASE CASE VS WEST–EAST PIPELINE

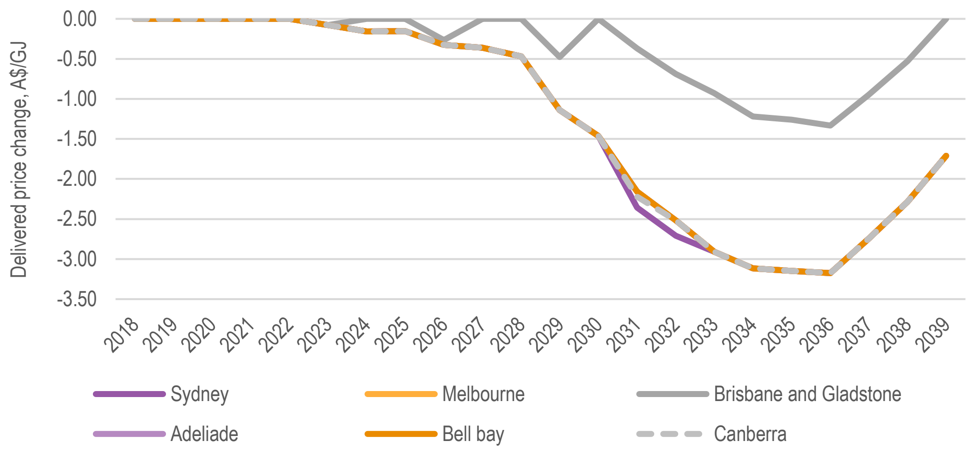


SOURCE: ACIL ALLEN'S GASMARK MODEL

The modelling shows that the West–East Pipeline would significantly affect the delivered prices at various nodes in east coast market.

Major metropolitan delivered price changes for the West–East Pipeline case (Route 1 — Burrup to Moomba) when compared with the Base Case are shown in **Figure 8.9**. Apart from Queensland, the delivered price in other locations changes by around \$3/GJ by the mid-2030s and then converges back toward the Base Case.

FIGURE 8.9 DELIVERED GAS PRICE CHANGES (A\$/GJ) FOR WEST–EAST PIPELINE RELATIVE TO BASE CASE



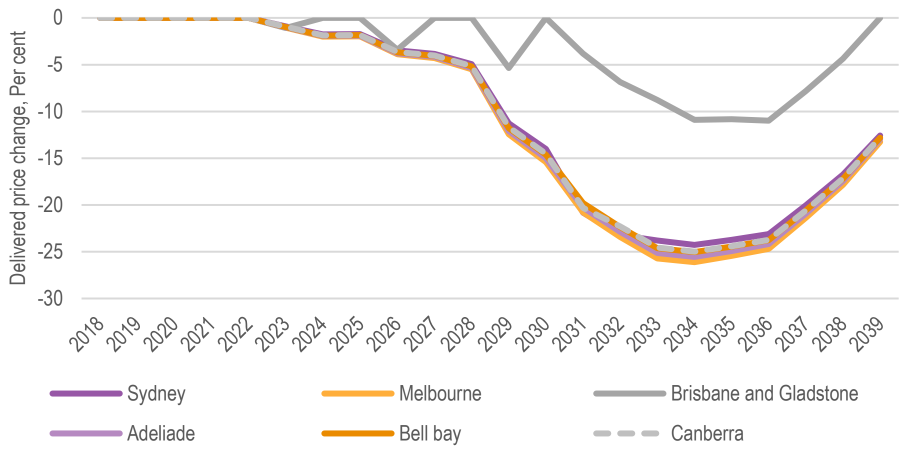
Note: Bell bay node represent the Tasmanian prices

SOURCE: ACIL ALLEN GASMARK MODEL

Delivered gas price changes in percentage terms is shown in **Figure 8.10**.

Potential delivered price benefits to mid-2030s are around 25 per cent for non-Queensland states and around 10 per cent to Queensland customers.

FIGURE 8.10 DELIVERED GAS PRICE CHANGES (PER CENT) IN ROUTE 1 — BURRUP TO MOOMBA — RELATIVE TO BASE CASE



Note: Bell bay node represent the Tasmanian prices

SOURCE: ACIL ALLEN GASMARK MODEL

8.6 Undiscounted value of impacts

The estimated undiscounted cost and benefit trends for various affected parties reported in the previous sections are summarised in this section (**Table 8.4**).

Total undiscounted net benefits generated by the West–East Pipeline vary by the affected party over the life of the project. For example, the pipeline developer and operator would benefit by nearly A$8.1 billion over the assumed operating life of the pipeline (to 2047). Savings for east coast customers would be around A$12.6 billion over the period to 2039 (the limit of the gas market modelling results).

The estimated undiscounted impacts do not provide any information on whether the proposed project is practicable or beneficial. Undiscounted cash flows do not consider the time value of monetised impacts.

TABLE 8.4 TOTAL UNDISCOUNTED COSTS AND BENEFITS

Undiscounted	Pipeline developer and operator (Period 2018 to 2047)	East coast gas consumers (Period 2018 to 2039)
	A$ million	A$ million
Total capex and opex costs	8,446	Not applicable
Total estimated gross benefit	13,406	12,649
Total net benefits or pre-tax cashflows	**8,124**	**12,649**

SOURCE: ACIL ALLEN ESTIMATES BASED ON THE GASMARK MODEL AND GHD

8.7 Discounted future costs and benefits

To compare the future costs with the future benefits, the future flows need to be discounted and brought into present value terms. The need to discount future cash flows can be viewed from two main perspectives, both of which focus on the opportunity cost of the cash flows implied by proposed pipeline.

The first perspective is the general observation that individuals prefer a dollar today to a dollar in the future. This is most obvious in the fact that banks need to pay interest on deposits to entice individuals to forgo current spending. This general preference for current consumption is reflected by the ‘rate of time preference’ and relates to all economic benefits (and costs), not just those that are financial in nature. Since individuals are not indifferent between cash flows from different periods, those flows cannot be directly compared. For monetised flows to be directly comparable in a benefit-cost analysis, those costs or benefits incurred in the future need to be discounted back to current dollar terms. This reflects society’s preferences, which place greater weight on consumption occurring closer to the present.

The second perspective is that flows of costs and benefits resulting from proposed pipeline also have an opportunity cost for investment. The proposed pipeline would impose costs on investors, and those costs will need to be funded in some way. This funding imposes costs on the affected party, either through the interest paid for borrowing the money, or the returns forgone when equity funds are not available to be used for other purposes.

The West–East Pipeline would therefore only be beneficial if it provides a return in excess of the cost to society of deferring consumption, or of the return that could have been earned on the best alternative use of the funds. By applying a discount rate to future cash flows, the required rate of return is explicitly taken into account in the net present value calculation.

Either approach demonstrates that the need to discount future cash flows can be viewed in terms of the opportunity cost of the cash flows, whether this is the cost of delaying consumption or the alternative investment opportunities forgone. Since most of the costs and benefits of pipeline are spread out over time, and their value depends on when they are received, discounting is crucial to the analysis.

The Office of Best Practice Regulation (OBPR) requires the calculation of net present values at an annual real discount rate of 7 per cent. As with any uncertain variable, sensitivity analysis should be conducted. So, in addition to the central discount rate, the net present values are calculated with real discount rates of 3 per cent and 10 per cent.

The benefits of the proposed West–East Pipeline are mainly realized in the future at around mid-2030s. Apart from the initial outlays by gas producers and pipeline operators, the operating costs incurred in operating the pipeline are spread out over the operating life of the pipeline. Thus, there is a distinct time-profile of benefits and costs corresponding to the proposed pipeline project. It is therefore appropriate to consider the time value of monetised net benefits.

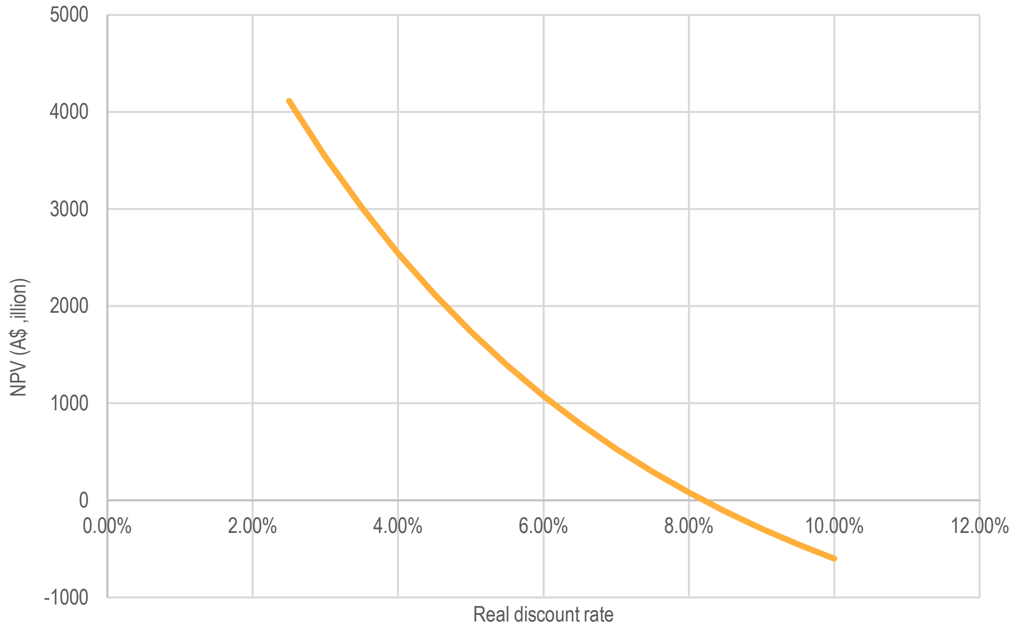
8.7.1 Pipeline developer and operator

The NPV of the West–East Pipeline expresses the difference between the discounted present value of future benefits and discounted present value of future costs. A positive NPV indicates that the project benefits are greater than its costs and vice versa. Since the pipeline capital costs occur at the start of the project and most of the expected revenue or benefit accrue much later, it is reasonable to expect that the discounted net benefits will be smaller than the undiscounted impacts.

In general, the higher the discount rate, the lower the present value of future benefits, because the value of the future stream of benefits is reduced relative to the up-front costs. Like other typical infrastructure investments, the pipeline has a downward sloping NPV curve as shown in **Figure 8.11**.

At a real discount rate of 8 per cent the pipeline NPV is zero over a 30-year period. The Internal Rate of Return (IRR) is based on the same principles as the NPV. When the discount rate equates to the IRR, the NPV is zero. Therefore, if the IRR is higher than the discount rate, there is a positive NPV. IRR can be viewed as the rate of return on the investment of the pipeline. For this investment to be financially viable, a pipeline owner would be seeking an IRR equal to or higher than their weighted average cost of capital (discount rate). Companies also require timely returns, making the ‘break even’ year important to them. This is the year in which the NPV turns positive.

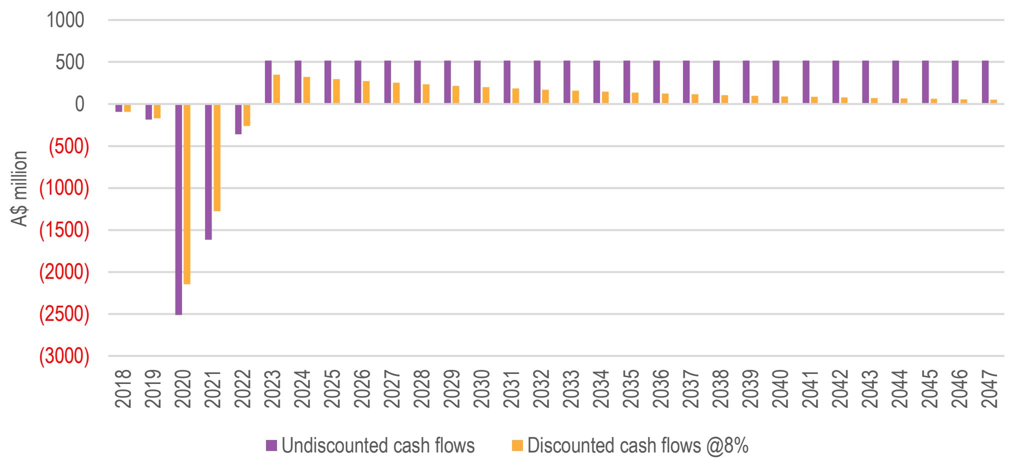
FIGURE 8.11 NPV CURVE FOR WEST–EAST GAS PIPELINE



SOURCE: ACIL ALLEN ESTIMATES BASED ON THE GASMARK MODEL AND GHD

At 6.4 per cent real discount rate the NPV benefits to the pipeline owners is nil. The discounted cash-flows of pipeline owner are shown in **Figure 8.12**.

FIGURE 8.12 PIPELINE OPERATOR'S DISCOUNTED CASHFLOWS



SOURCE: ACIL ALLEN ESTIMATES BASED ON THE GASMARK MODEL AND GHD

8.7.2 East coast customers

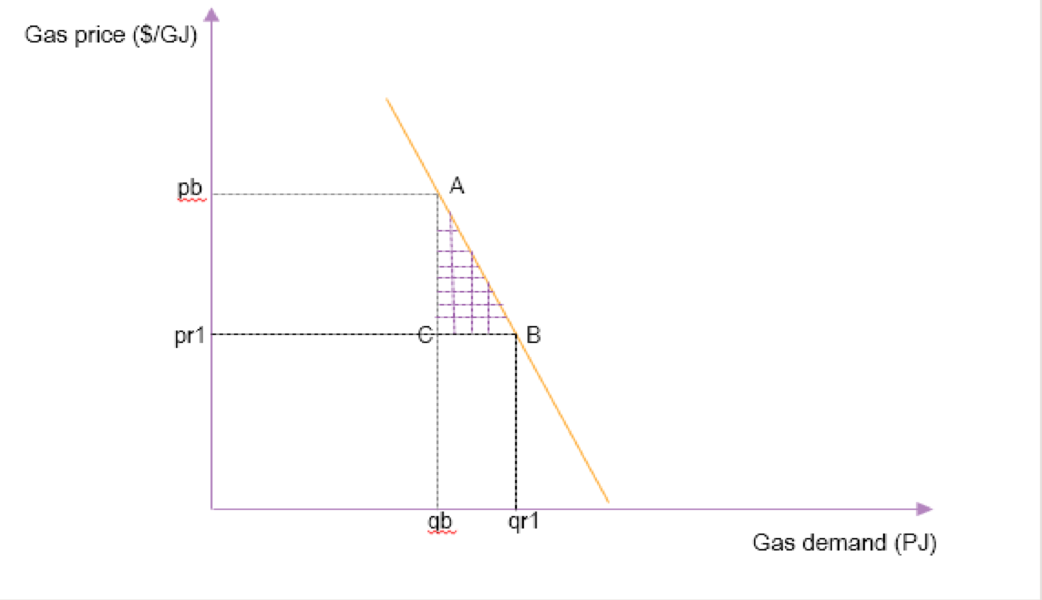
Consumers on the east coast will benefit from the lower gas prices relative to Base Case and from increased consumption of gas. The benefits are calculated by multiplying the delivered price difference between the Route 1 Option and the Base Case with the change in consumption. This is illustrated in **Box 8.1**. The expected cost savings amount to:

– For NSW and ACT customers over the period 2018–2039 period, undiscounted savings are A$3,446 million and the discounted gas cost savings are A$1,021 million at 8 per cent discount rate.

- For Victorian customers over the period 2018–2039 period, undiscounted savings are A$5,627 million and the discounted gas cost savings are A$1,664 million at 8 per cent discount rate.
- For Queensland customers (including LNG) over the period 2018–2039 period, undiscounted savings are A$2,133 million and the discounted gas cost savings are A$1,415 million at 8 per cent discount rate.
- For South Australian customers over the period 2018–2039 period, undiscounted savings are A$1,275 million and the discounted gas cost savings are A$381 million at 8 per cent discount rate.
- For Tasmanian customers over the period 2018–2039 period, undiscounted savings are A$168 million and the discounted gas cost savings are A$49 million at 8 per cent discount rate.

BOX 8.1 A CHANGE IN CONSUMER SURPLUS DUE TO A PRICE DECREASE

Microeconomic theory provides the basic technical foundations for cost benefit analysis. The aggregate net consumer surplus estimated in this study is illustrated in diagram below. Under most circumstances change in consumer surplus can be used as a reasonable measure of a policy change. The figure has gas price as a function of quantity of gas consumed. At Base Case – no West–East Pipeline – the price and quantity consumed are given by **pb** and **qb** respectively. With the West–East Pipeline, the price of gas decreases to **pr1** and quantity consumed increases to **qr1** (an inelastic demand curve). This would result a benefit to consumers in east coast equal to the area of the trapezoid pb A B pr1. This benefit results due to the existing customers paying lower prices at the **qb** quantity they previously purchased and some consumer gains due to the additional consumption of **qr1- qb**. The triangle **ABC** is a net consumer benefit.



SOURCE: ACIL ALLEN CONSULTING

Because of the complexity of choosing the correct discount rate, and the potential impact that alternative discount rates can have on the net benefit, OBPR has recommended that three selected rates be used separately in the analysis.

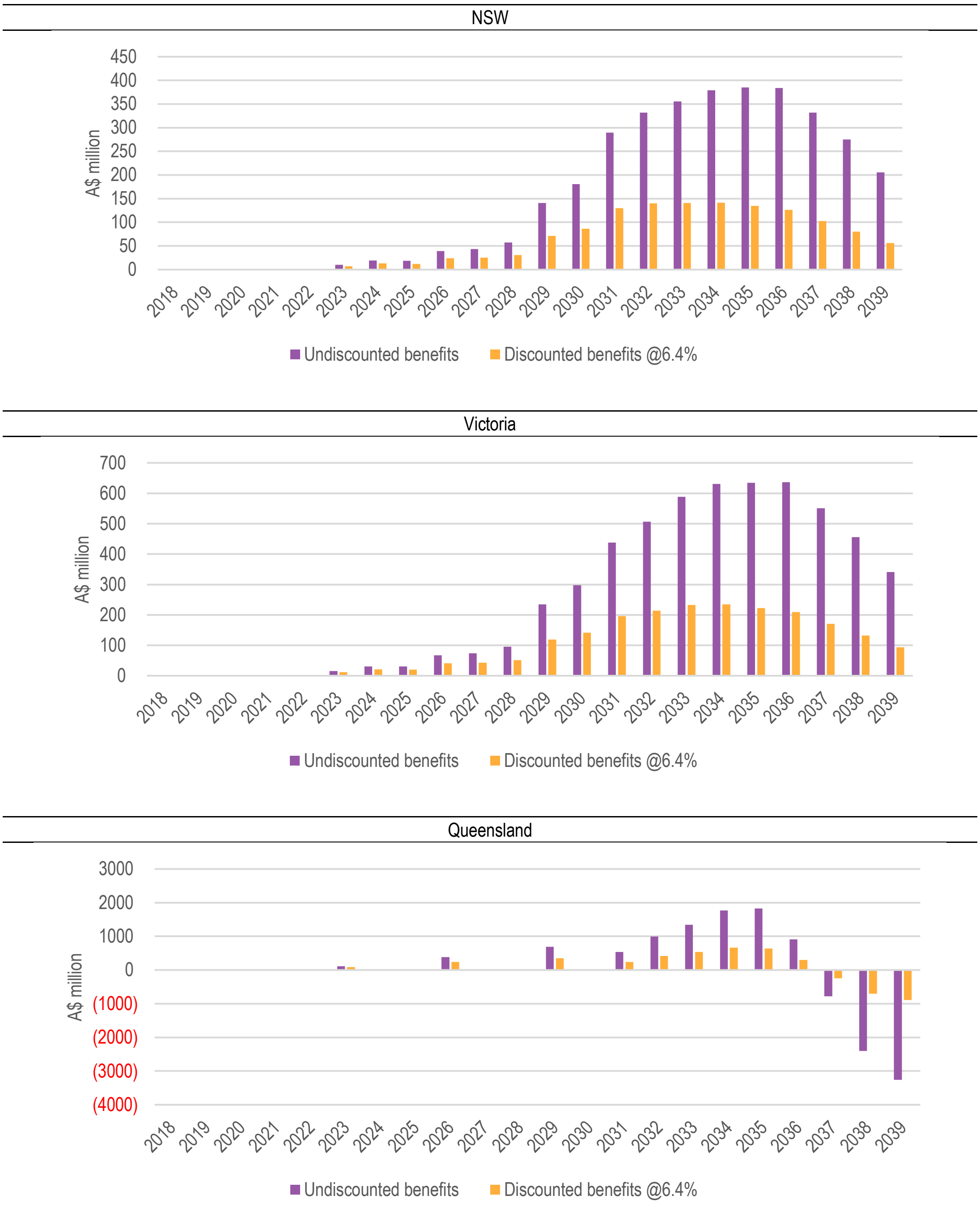
Typically, each option is conducted with one discount rate applied to all benefits and all costs over the entire time frame of interest. In 1970, Kenneth Arrow and Robert Lind[18] explained that this may be inappropriate, because different discount rates should be used depending on the nature of the benefits and costs, including risk and uncertainty, and depending on who is affected. For example, if all costs and benefits are spread across the whole community it could be appropriate to use a risk-free rate. However, if sizeable benefits and costs accrue directly to particular people or groups, they also bear the cost of bearing risk and uncertainty, which may be significant. Then, the discount rate should

[18] K. J. Arrow and R. C. Lind, "Uncertainty and the Evaluation of Public Investment Decisions," Amer. Econ. Rev., June 1970, 60, 364-78

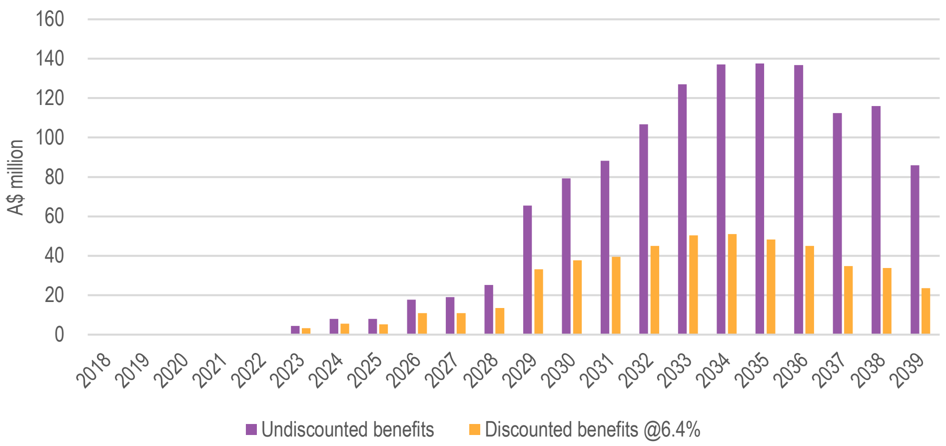
be consistent with the preferences and attitudes of the relevant people. Therefore, different streams of benefits and costs should be discounted differently, according to whether they accrue publicly or privately. Application of the insights of Arrow and Lind to an assessment of the proposed pipeline would suggest using a risk-free discount rate for public benefits in the form of gas cost savings effects, but a risk-inclusive discount rate for private benefits to gas producers and pipeline operators. The real options literature has also made a strong case for use of multiple discount rates for different streams of costs and benefits, with different risk and uncertainty attributes.

The projected undiscounted and discounted benefits to gas consumers, at the 8 per cent discount rate which reflects the IRR of the West–East Pipeline under the gas market modelling assumptions are provided in **Figure 8.13** by state. The state that benefits the most from lower gas costs will be Victoria.

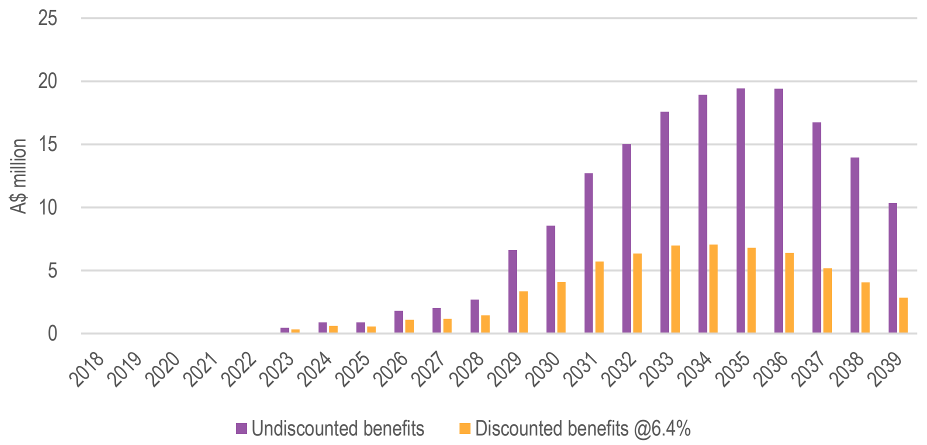
FIGURE 8.13 TIME PROFILE OF GAS COST SAVINGS BY STATE



South Australia



Tasmania



SOURCE: ACIL ALLEN ESTIMATES BASED ON THE GASMARK MODEL

The discounted value of impacts for customers in Eastern Australia are summarised in **Table 8.5**. Real discount rates of 8 per cent, 3 per cent and 10 per cent are used to calculate net present values of benefits. Customers in the east coast market could potentially save gas costs between $3.7 billion and $8.6 billion in Net Present Value terms over the period to 2039 as a result of the West–East Pipeline. This translates to an annual discounted gas cost savings between $203 million and $479 million.

TABLE 8.5 WEST EAST PIPELINE BENEFITS TO CUSTOMERS IN EAST COAST

State	Customer type	Undiscounted	Discounted		
		A$ million	A$ million	A$ million	A$ million
			NPV 8%	NPV 3%	NPV 10%
NSW/ACT	Commercial/Residential	1,388	410	872	321
	Small Industrial	1,413	421	890	329
	Large Industrial	378	112	238	88
	Power Generation - OCGT	24	7	15	5
	Power Generation - CCGT	239	71	150	55
	Power Generation - cogeneration	4	1	3	1
	Sub-total	**3,446**	**1,021**	**2,166**	**799**
Vic.	Commercial/Residential	3,670	1,082	2,302	846

State	Customer type	Undiscounted		Discounted	
	Small Industrial	1,593	476	1,004	373
	Power Generation - steam turbine	0	0	0	0
	Power Generation - OCGT	46	14	29	11
	Power Generation - CCGT	318	91	198	71
	Sub-total	**5,627**	**1,664**	**3,534**	**1,301**
Qld	Commercial/Residential	63	18	39	14
	Small Industrial	101	30	63	23
	Large Industrial	513	150	321	117
	Power Generation - OCGT	51	15	32	12
	Power Generation - CCGT	377	110	236	86
	Power Generation - cogeneration	70	21	44	16
	LNG	957	1,071	1,269	951
	Sub-total	**2,133**	**1,415**	**2,005**	**1,218**
SA	Commercial/Residential	279	83	175	65
	Small Industrial	320	95	201	74
	Large Industrial	144	45	92	36
	Power Generation - steam turbine	109	33	69	26
	Power Generation - OCGT	13	4	8	3
	Power Generation - CCGT	349	103	220	81
	Power Generation - cogeneration	60	18	38	14
	Sub-total	**1,275**	**381**	**803**	**299**
Tas.	Commercial/Residential	91	27	57	21
	Small Industrial	32	10	20	7
	Large Industrial	42	13	27	10
	Power Generation - OCGT	2	1	2	1
	Power Generation - CCGT	0	0	0	0
	Sub-total	**168**	**49**	**105**	**39**
	TOTAL (over period to 2039)	**12,649**	**4,530**	**8,613**	**3,656**
	Annual gas cost savings	**703**	**253**	**479**	**203**

SOURCE: ACIL ALLEN ESTIMATES BASED ON GASMARK MODEL

8.8 Conclusion

The benefit cost analysis undertaken to assess the proposed West–East Pipeline (Route 1 from Burrup to Moomba) demonstrates a net benefit to customers in the east coast market. The estimated total net benefits of gas cost savings over an eighteen-year period range between $3,656 million (10 per cent discount rate) and $8,613 million (3 per cent discount rate) depending upon the assumptions. On an annualised basis, the estimated net benefits would range between $203 million and $479 million per year.

9 ECONOMIC IMPACT ANALYSIS

9.1 Introduction

To provide information on the broader economic impacts potentially arising from the project at the state, territory and national levels, ACIL Allen has undertaken computable general equilibrium (CGE) modelling of the Route 1 option. This analysis complements and extends the cost benefit analysis discussed in the previous chapter and provides a better indication of the nation-building potential of the project. For this analysis we used ACIL Allen's CGE model, *Tasman Global*. *Tasman Global* is a multi-sector dynamic model of the Australian and world economy that has been used for many similar modelling projects including for numerous gas development and gas pipeline projects. An overview of the model is provided in Appendix G.

The capital and operating expenses from the engineering assessment along with the gas use and price trends projected from the *GasMark* modelling with and without the pipeline have been used to inform the *Tasman Global* Base Case (without the pipeline) and the Route 1 policy cases (with the pipeline). The differences between the economic projections with and without the pipeline provides a forecast of the total economic impacts of the various route options, including the wider economic impacts associated with the construction and operation of the pipeline and the impact of changes in the availability and price of natural gas (and flow-ons into other economic sectors including LNG production and electricity) in each region and across the nation as a whole.

CGE models produce a wide variety of economic metrics. To assist the Department in understanding the National Interest effects of the pipeline, key metrics reported in this Chapter include:

— **Real economic output** (as measured by real Gross Domestic Product (GDP) and real Gross State Product (GSP)): GDP/GSP is defined as the sum of value added by all producers who are Australian/State residents, plus any product taxes (minus subsidies) not included in output. A positive deviation of real economic output from the Base Case implies that the proposed West–East Pipeline investment will enable the Australian economy to produce more real goods and services potentially available for consumption.

— **Real income:** The change in real income in CGE models such as *Tasman Global* is a measure of the change in economic welfare of the residents of the state or country. The change in real income is equal to the change in real economic output plus the change in net foreign income transfers plus the change in terms of trade. In contrast to measures such as real GDP, real income accounts for the impacts of foreign ownership and debt repayments as well as changes in the purchasing power of Australian residents as a result of a project or policy.

— **Employment and real wages:** *Tasman Global* also produces the net labour market impact of the construction and operations of a major project.

9.2 Assessment methodology

The macroeconomic impacts of a policy, project or other activity can be estimated using a variety of economic analysis tools. The most common methods utilised are input-output multiplier analysis and computable general equilibrium (CGE) modelling. The selection of the right tool is critical to the accuracy of the estimated impacts and depends upon the characteristics of the project/industry. Sometimes a range of tools are required. Appendix G contains a brief discussion of input-output multipliers and CGE models.

By their nature, input-output multipliers and CGE models focus on 'market impacts' across the economy (that is, impacts on activities with observed market prices). Analysis of various 'non-market impacts', such as property right infringements, potential loss of biodiversity, changes in air quality, social justice implications and so forth may also be relevant in assessing the full implications of a project or policy.

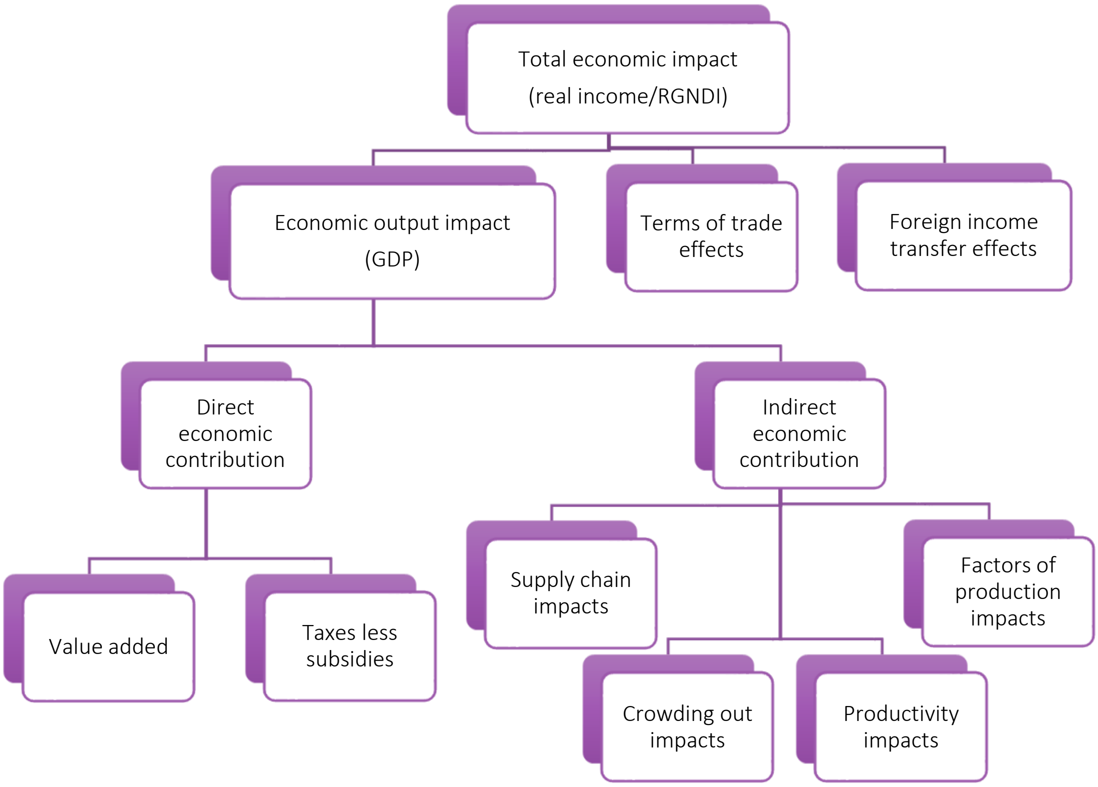
Fundamentally, although various aspects of a policy or project—such as the number of jobs or the size of the investment expenditure—are of relevance to certain stakeholders, the key aggregate measure of the macroeconomic impact of a project is the extent to which the total income of the economy changes as a result of the policy or project. Typically, this is measured by real gross national disposable income (RGNDI), although real gross domestic product (GDP) and consumer surplus (among others) can also be important aggregate measures depending on the nature of the policy or project being analysed.

The main factors that need to be considered when analysing the macroeconomic impacts of a project or policy include:

- the direct and indirect contribution to the economy as a result of the activities associated with the project
- any crowding out implications as resources are potentially diverted from other productive activities to undertake the project being analysed
- any productivity effects generated as a direct result of the policy or project activities – particularly any enduring productivity changes or productivity impacts on other activities not directly associated with the project or policy
- any changes to the factors of production in the economy
- any implications associated with changes in terms of trade or foreign income transfers
- whether there is a dynamic element to the size of any of the above effects (due to different phases of the project for example).

Figure 9.1 shows these components graphically. Some of these effects may be negligible while others may be very significant and an understanding of the effects helps determine the most appropriate tool(s) for the analysis.

FIGURE 9.1 ESTIMATING THE MACROECONOMIC IMPACT OF A PROJECT OR POLICY



SOURCE: ACIL ALLEN CONSULTING

For many projects, static estimates of the direct economic contribution and supply chain implications can be obtained by using I-O multipliers. Estimating the size of other components using multiplier techniques is either not possible or very complex, as is estimating the economic impacts through time. In contrast, most CGE models can estimate all the components shown in **Figure 9.1** with dynamic CGE models able to estimate the impacts through time.

A project the size of the West–East Pipeline will have the potential for crowding out implications as well as terms of trade and foreign income transfers effects. Consequently, CGE modelling has been used for this economic impact assessment.

For this analysis, ACIL Allen's CGE model, *Tasman Global*, was used to estimate the impacts of the construction and operation activities associated with the Project.

9.3 The *Tasman Global* CGE model

Tasman Global is a large scale, dynamic, CGE model of the world economy that has been developed in-house by ACIL Allen. *Tasman Global* is a powerful tool for undertaking economic analysis at the regional, state, national and global levels.

CGE models mimic the workings of the economy through a system of interdependent behavioural and accounting equations which are linked to an input-output database. These models provide a representation of the whole economy, set in a national and international trading context, starting with individual markets, producers and consumers and building up the system via demands and production from each component. When an economic shock or disturbance is applied to the model, each of the markets adjusts according to the set of behavioural parameters which are underpinned by economic theory. The generalised nature of CGE models enable a much broader range of analysis to be undertaken (generally in a more robust manner) compared to I-O multiplier techniques, which are also often applied in economic impact assessments

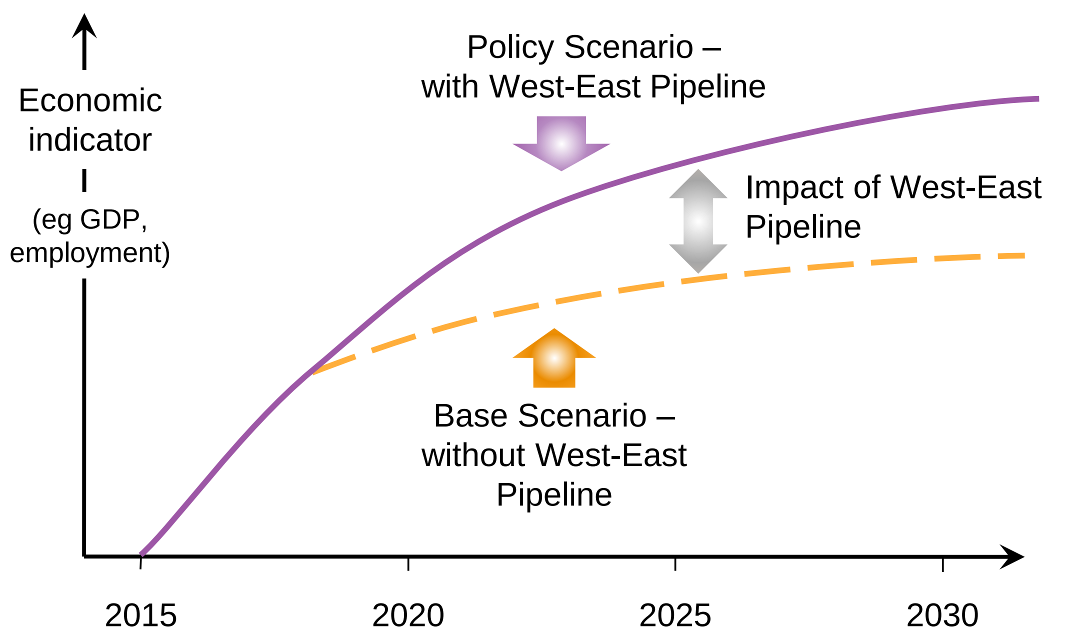
More detail of the *Tasman Global* model is provided in Appendix G of this report.

9.3.1 A dynamic model

Tasman Global is a model that estimates relationships between variables at different points in time. This is different from comparative static models, which compare two equilibriums (one before a policy change and one following). A dynamic model such as *Tasman Global* is useful when analysing issues where both the timing of economic impacts and the adjustment path that economies follow are relevant in the analysis.

In applications of the *Tasman Global* model, a Base Case simulation forms a 'business-as-usual' basis with which to compare the results of various simulations. The Base Case provides projections of growth in the absence of the Project (such as GDP, population, labour supply, industry output, etc.) and provides projections of endogenous variables such as productivity changes and consumer tastes. The Policy Case assumes all productivity improvements, tax rates and consumer preferences change as per the Base Case projections but also includes the proposed Project. The two scenarios give two projections of the economy and the net impact of the Project is then calculated as deviations from the Base Case (see **Figure 9.2**).

FIGURE 9.2 ILLUSTRATIVE SCENARIO ANALYSIS USING TASMAN GLOBAL



Note: Indicative only. In reality the projected impacts of a project or policy can be positive, negative, neutral or mixed.

SOURCE: ACIL ALLEN CONSULTING

9.3.2 Database aggregation

The database which underpins the model contains a wealth of sectoral detail. The foundation of this information is the set of input-output tables that underpin the database. Industries in the model can be aggregated or disaggregated as required for a specific project. For this project the industries have been aggregated to 47 industries/commodities as presented in **Table 9.1**.

The aggregation was chosen to provide the detail relevant for this analysis.

TABLE 9.1 INDUSTRY/COMMODITY AGGREGATION USED FOR TASMAN GLOBAL MODELLING

	Industry/commodity		Industry/commodity
1	Vegetables, fruit and nuts	25	Wood and paper products; publishing and printing (excluding furniture)
2	Other crops	26	Fabricated metal products
3	Cattle	27	Motor vehicle and parts
4	Other livestock	28	Other transport equipment
5	Fishing	29	Electronic equipment
6	Forestry	30	Other machinery and equipment
7	Meat products	31	Other manufacturing
8	Other processed food and beverages	32	Water
9	Coal	33	Gas distribution
10	Oil	34	Construction
11	Gas	35	Trade services (includes all retail and wholesale trade, hotels and restaurants)
12	LNG	36	Road transport
13	Iron ore	37	Rail and pipeline transport
14	Bauxite	38	Water transport
15	Other mining	39	Air transport
16	Iron & steel	40	Other transport services
17	Alumina	41	Communications services
18	Primary aluminium	42	Insurance services
19	Petroleum & coal products	43	Other financial services
20	Electricity	44	Other business services
21	Other nonferrous metals	45	Recreational and other services
22	Non-metallic minerals (including cement, plaster, lime, gravel)	46	Government services (including public administration and defence)
23	Chemicals, rubber, plastics	47	Dwellings
24	Textiles, clothing and footwear		

Note: Excludes micro-industries developed specifically for this analysis

SOURCE: ACIL ALLEN CONSULTING

9.3.3 Micro industry approach

To accurately assess the economic impacts or economic contribution of a major project, such as the West–East Pipeline, the project must be accurately represented in the model's database. An accurate representation can be guaranteed by establishing the proposed project as a new 'micro' industry in the database.

The micro industry approach is so called because it involves the creation of one or more new, initially very small, industries in the *Tasman Global* database. The specifications of each of the micro industry's costs and sales structures are directly derived from the financial data for the project to be analysed. At the outset, the new industry is necessarily very small so that its existence in the *Tasman Global* database does not affect the database balance or the "business-as-usual" Base Case outcomes.

Besides having a separate cost structure for the project of interest, a further challenge is to faithfully represent the time profile of the individual cost items. This is particularly important for the investment phase where there are typically large changes in demands for machinery, labour and imported components year on year. This challenge is met in *Tasman Global* through incorporating detailed year on year, input specific shocks by source

Using the micro industry approach for project evaluations is the most accurate way to capture the detailed economic linkages between the project and the other industries in the economy. This approach has been developed by ACIL Allen because each project is unique relative to the more aggregated industries in the *Tasman Global* database.

Consequently, in addition to the 47 industries identified in **Table 9.1**, the database also identifies the construction and operation phases of the Project as separate industries with their own input cost structure, sales, employment, tax revenues and emissions based on detailed information generated as part of this analysis.

Another important aspect in the CGE modelling approach used for this analysis is to have separate identification of the capital stock created as part of the project's investment phase and isolating it until the capital is available for use, thereby preventing the economy gaining false benefits from, say, half a bridge. In the past, some CGE models potentially overstated the impact of an investment, because investment in one period was automatically added to capital stock in the next period and was made available to the rest of the economy, thereby spuriously increasing GDP.

9.4 Measures of macro-economic impacts

One of the most commonly quoted macroeconomic variables at a national level is real GDP, which is a measure of the aggregate output generated by an economy over a given period (typically a year). From the expenditure side, GDP is calculated by adding together total private and government consumption, investment and net trade. From the income side, GDP can be calculated as the sum of returns to the primary factors (labour, capital and natural resources) employed in the national economy plus indirect tax revenue. The regional level equivalent to GDP is Gross Regional Product (GRP) – at the state level it is called GSP (Gross State Product). To reduce the potential confusion with the various acronyms, the term **economic output** has been used in the discussion of the results presented in this report.

These measures of the real economic output of an economy should be distinguished from measures of the economy's real income, which provide a better indication of the economic welfare of the residents of a region. It is possible for real economic output to increase (that is, for GDP to rise) while at the same time real income (economic welfare) declines. In such circumstances people and households would be worse off despite economic growth.

In *Tasman Global*, the relevant measure of real income at the national level is RGNDI as reported by the Australian Bureau of Statistics (ABS).

The change in a region's real income as a result of a new project change is the change in real economic output plus the change in net external income transfers plus the change in the region's terms of trade (which measure the change in the purchasing power of the region's exports relative to its imports). As Australians have experienced first-hand in recent years, changes in the terms of trade can have a substantial impact on residents' welfare independently of changes in real economic output.

In global CGE models such as *Tasman Global*, the change in real income is equivalent to the change in consumer welfare using the equivalent variation measure of welfare change resulting from exogenous shocks. Hence, it is valid to say that the projected change in real income (from *Tasman Global*) is also the projected change in consumer welfare.

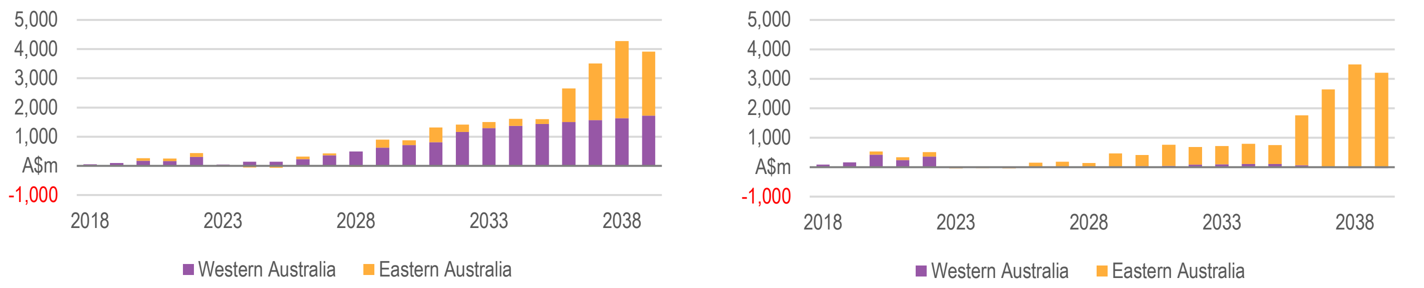
9.5 Economic modelling results

9.5.1 Real economic output and real income

Figure 9.3 shows the change in real economic output and real income in Eastern and Western Australia for each year of the projection period (2018 to 2039) under the Route 1 policy case (with the West–East Pipeline) compared to the Business as Usual Case (without the West–East Pipeline). A summary of the aggregate projected impacts is presented in **Table 9.2**.

FIGURE 9.3 CHANGE IN REAL ECONOMIC OUTPUT AND REAL INCOME AS A RESULT OF THE PROJECT, RELATIVE TO THE BASE CASE (IN 2016-17 TERMS)

A. Real economic output | B. Real income



SOURCE: ACIL ALLEN CONSULTING

In Western Australia, the largest changes in real economic output occur broadly in line with the projected value of production (see **Figure 9.3**A**)**. This is not surprising as the operations phase is where the key benefits of the project will be realised for Western Australia—namely, through the increased value of production obtained from the current resources. In contrast, the construction phase is largely increasing demand for scarce factors of production and so has a smaller effect on economic output compared to the size of the investment.

However, the additional construction activity associated with the project has a noticeable effect on the real income of residents in Western Australia as there is increased demand for labour and goods and services and this boosts local incomes relative to the Base Case (see **Figure 9.3**B**)**. During the operations phase, however, the projected increase in the real incomes of Western Australia is much less than the projected increase in real economic output. This is because although the gas production is happening in Western Australia, the taxes and profits are distributed elsewhere—notably to Eastern Australian residents (on the basis of relative population size) and to foreign equity owners. On a per capita basis, the growth in real incomes of Western Australians is comparable with the growth in Eastern Australia.

The story for Eastern Australia is more complicated. While there is a loss of gas production to Western Australia, the crowded out fields are more expensive than the new gas supplied by Western Australia. In economic terms, this means that they effectively embodied more scarce factors than the new gas supply. Replacing the gas produced from more marginal fields with the cheaper gas frees up scarce factors of production and, combined with the reduction in gas prices improving the competitiveness of Eastern Australian industries, allows Eastern Australia to increase output from alternative industries. In net terms, while the crowding out effect is bigger in the period 2023-2025 (leading to a projected loss of real economic output relative to the Base Case), the price benefit over the period 2026-2039 is projected to more than offset the crowding out effect leading to a net increase in real economic output over this period.

The projected jump in the real economic output of Eastern Australia in the last few years of the projection period (2036-2039) is due to the ability to extend the economic life of the Gladstone LNG facilities.

TABLE 9.2 PROJECTED CUMULATIVE CHANGE IN REAL ECONOMIC OUTPUT AND REAL INCOME IN EACH REGION AS A RESULT OF THE WEST–EAST PIPELINE PROJECT, RELATIVE TO THE BASE CASE (IN 2016-17 TERMS)

	Real economic output			Real income		
	Total (2018 to 2039)	NPV (3% discount rate)	NPV (7% discount rate)	Total (2018 to 2039)	NPV (3% discount rate)	NPV (7% discount rate)
	2016-17 A$m	2016-17 A$m	2016-17 A$m	2016-17 A$m	2016-17 A$m	2016-17 A$m
Western Australia	16,042	10,264	5,966	1,663	1,416	1,192
Eastern Australia	9,989	5,856	3,004	15,877	9,466	4,967
Total Australia	**26,031**	**16,121**	**8,970**	**17,541**	**10,882**	**6,159**

Note: NPV = net present value. Real economic output for Western Australia is equivalent to real GSP, while real economic output for Australia is equal to GDP.
SOURCE: ACIL ALLEN CONSULTING

Real economic output

Over the period 2018 to 2039, the West–East Pipeline under the Route 1 option is projected to increase the real economic output of:

- *Western Australia* by a cumulative total of $16.0 billion relative to the Base Case (with a net present value of $6.0 billion, using a 7 per cent real discount rate)
  - $805 million of the projected benefit occurs during the construction phase with the remainder spread during the modelled operations phase
- *Eastern Australia* as a whole by a cumulative total of $10.0 billion relative to the Base Case (with a net present value of $3.0 billion, using a 7 per cent real discount rate)
  - $273 million of the projected benefit occurs during the construction phase with the remainder spread during the modelled operations phase.
- *Australia* as a whole by a cumulative total of $26.0 billion relative to the Base Case (with a net present value of $9.0 billion, using a 7 per cent real discount rate)

To place the projected changes in economic output estimates in perspective, the discounted present value (using a 7 per cent discount rate) is equivalent to 2.4 per cent of Western Australia's current GSP and 0.5 per cent of Australia's current GDP.

Real income

Real income is a measure of the ability to purchase goods and services, adjusted for inflation. A rise in real income indicates a rise in the capacity for current consumption, but also an increased ability to accumulate wealth in the form of financial and other assets. The change in real income from a development is a measure of the change in welfare of an economy.

The extent to which local residents will benefit from the additional economic output depends on the level of ownership of the capital (including the natural resources) utilised in the business as well as any wealth transfers undertaken by Australian governments as a result of the taxation revenues generated by the Project.

While most of the additional economic activity is associated with the increased gas production in Western Australia, only a portion of the project capital is assumed to be owned by Western Australian residents[19]. Consequently, a significant portion of the total wealth generated by the economic activity is transferred outside Western Australia.

The Western Australian Government will receive some additional taxes (such as payroll taxes) because of the project. Similarly, the Australian Government will receive higher taxes through higher personal income and company tax receipts. Where this additional income will be spent is unknown; it has been assumed for the purposes of this study that it will be spent proportionately to the population in each region of Australia.

[19] More specifically, it has been assumed that 40 per cent of after-tax revenues accrue to foreign investors (including foreign debt holders) with the remainder distributed among each region of Australia based on their relative population.

Consequently, a significant portion of the real income benefit associated with the project (in absolute terms rather than *per capita* terms) is projected to accrue to residents outside of Western Australia.

More specifically, over the period 2018 to 2039, the project is projected to increase the real income of:

— *Western Australia* by a cumulative total of $1.7 billion, relative to the Base Case (with a net present value of $1.2 billion, using a 7 per cent real discount rate)
  – $1.3 billion of the projected benefit occurs during the construction phase with the remainder spread during the modelled operations phase
— *Eastern Australia* as a whole by a cumulative total of $15.9 billion, relative to the Base Case (with a net present value of $5.0 billion, using a 7 per cent real discount rate)
  – $313 million of the projected benefit occurs during the construction phase with the remainder during the modelled operations phase.
— *Australia* as a whole by a cumulative total of $17.5 billion, relative to the Base Case (with a net present value of $6.2 billion, using a 7 per cent real discount rate)

To place these projected changes in income in perspective, the discounted present values (using a 7 per cent discount rate) are equivalent to a one-off increase in the average real income of all current residents of:

— *Western Australia* by approximately $462 per person
— *Australia* as a whole by approximately $250 per person.

9.5.2 Employment

As well as creating some ongoing employment in the Western Australian economy, the project will generate short-term jobs related to the construction phase of the project. In addition to the direct jobs generated on-site, the construction and installation, and production phases will require a range of Western Australian sourced goods and services. Production of these inputs will further increase the demand for labour across the Western Australian economy.

A key issue when estimating the impact of a project is determining how the labour market will clear.[20] For this analysis, increases in the demand for labour in Western Australia can be met by three mechanisms: increasing migration from Eastern Australia; increasing participation rates and/or average hours worked; and by reducing the unemployment rate. In the model framework, the first two mechanisms are driven by changes in the real wages paid to workers in the local region while the third is a function of the additional labour demand relative to the Base Case. Given the moderate unemployment rate assumed throughout the projection period, changes in the real wage rate account for the majority of the additional labour supply in the policy scenario relative to the Base Case.

It should be noted that this analysis does not assume any change in net foreign migration as a result of the Project.

Compared to other industries—particularly with respect to the growing manufacturing and services industries in Eastern Australia—the operations of the conventional gas industry in Western Australia is capital intensive rather than labour intensive. Contrary to what may be expected therefore, this means the restructuring of the Australian economy toward increased gas production in Western Australia and other activity in Eastern Australia creates a pull factor for labour *away* from Western Australia towards Eastern Australia.

[20] As with other CGE models, the standard assumption within *Tasman Global* is that all markets clear (i.e. demand equals supply) at the start and end of each time period, including the labour market. CGE models place explicit limits on the availability of factors and the nature of the constraints can greatly change the magnitude and nature of the results. In contrast, most other tools used to assess economic impacts, including I-O multiplier analysis, do not place constraints on the availability of factors. Consequently, these tools tend to overestimate the impacts of a project or policy.

Employment creation

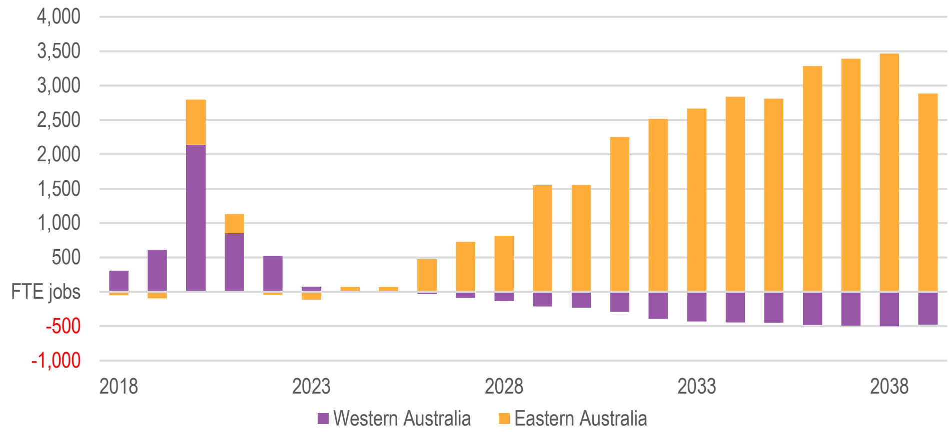
Over the life of the West–East Pipeline it is projected that approximately 31,800 employee years[21] of full time equivalent (FTE) direct and indirect jobs will be created. More specifically, it is projected that the Project will increase employment in:

— *Western Australia* by –133 employee years (+4,426 employee years during the construction phase and–4,560 employee years during operations, see **Figure 9.4**)

— *Eastern Australia* as a whole by +31,972 employee years (+750 employee years during the construction phase and +31,222 employee years during operations)

— *Australia* as a whole by +31,839 employee years (+5,176 employee years during the construction phase and +26,663 employee years during operations).

FIGURE 9.4 PROJECTED CHANGE IN TOTAL EMPLOYMENT AS A RESULT OF THE PROJECT, RELATIVE TO THE BASE CASE (FULL-TIME EQUIVALENT JOBS)



Note: FTE = full-time equivalent.

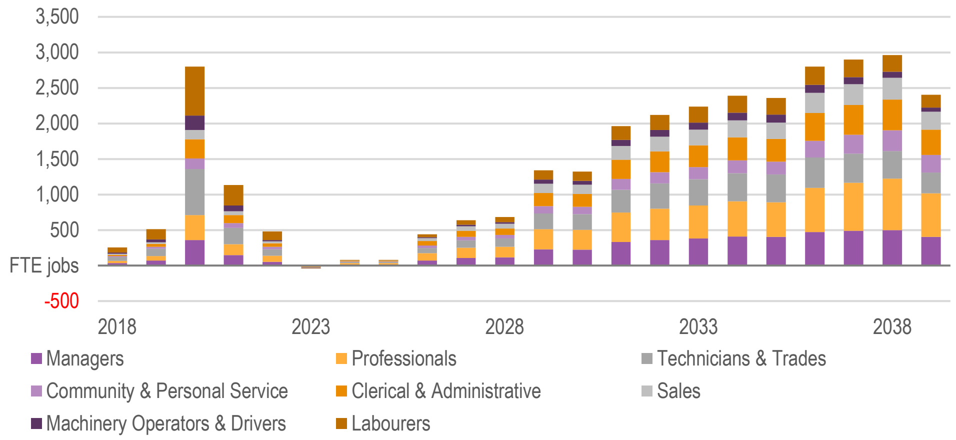
SOURCE: ACIL ALLEN CONSULTING

The projected decline in employment Eastern Australia during certain years of the construction phase is due to movement of labour towards Western Australia to meet some of the skilled labour demanded by the project and the relative demand for labour from each region during different stages of the construction.

Under the Route 1 option, there will be a change in the employment across a range of different skills. **Figure 9.5** shows the broad classifications and numbers of employees stimulated across Australia by the project over its life. The data reflect the high proportion of skilled machinery operators and drivers as well as technical and professional personnel required to construct a project of this type. Other jobs are stimulated in response to consumer's consumption patterns and their higher incomes, relative to the Base Case.

[21] An employee year is equivalent to the employment of 1 FTE person for one year. Alternatively it can represent employment of, say, two full-time people for half a year each, or one 0.5 FTE person for two years.

FIGURE 9.5 PROJECTED ADDITIONAL AUSTRALIAN EMPLOYMENT BY OCCUPATION AS A RESULT OF THE PROJECT, RELATIVE TO THE BASE CASE (FULL-TIME EQUIVALENT JOBS)



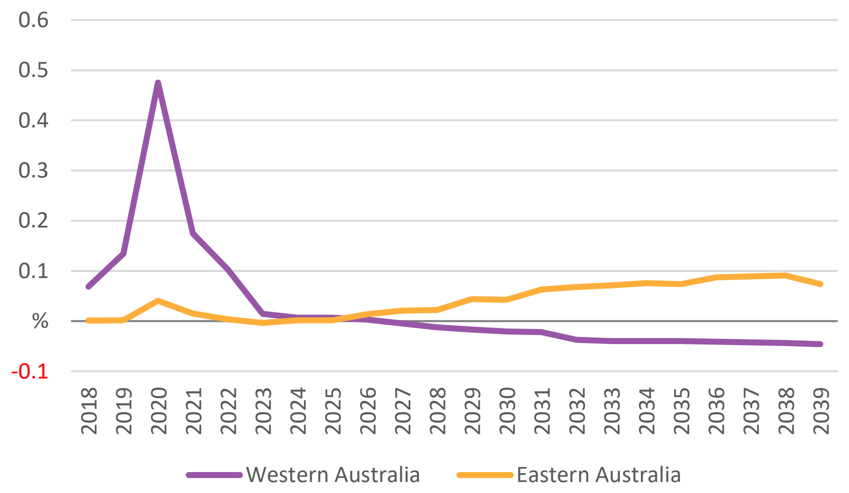
Note: FTE = full-time equivalent.

SOURCE: ACIL ALLEN CONSULTING

9.6 Real wages

Figure 9.6 shows the projected changes in real wages in each region as a result of the construction and operation of the West–East Pipeline. The projected changes in real wages follow the changes in labour demand, with wages in each region acting to balance demand and supply in each year. In addition, the magnitude of the projected changes in real wages is a function of the relative size of the demand and supply imbalance with respect to the overall size of the labour market (that is, large percentage increases in labour demand relative to the Base Case will tend to result in large percentage increases in real wages relative to the Base Case). In the context of the project, average real wages are also affected by the higher average wages (including allowances) paid to direct employees compared to other industries.

FIGURE 9.6 PROJECTED CHANGE IN REAL WAGES UNDER ROUTE 1 OPTION, RELATIVE TO THE BASE CASE



SOURCE: ACIL ALLEN CONSULTING

As can be seen from the figures above, there is a significant increase in average real wages in Western Australia during the construction phase of the project, with the peak increase in real wages in each region occurring during the years when labour demand is the highest.

During the pre-production phase, real wages in Western Australia are projected to increase by an average of 0.2 per cent relative to the Base Case, with a peak of 0.5 per cent in 2020.

Over the operations phase, real wages in Western Australia are projected to fall by an average of –0.02 per cent relative to the Base Case, while real wages in Eastern Australia increase by an average of 0.05 per cent (**Figure 9.6**). Given the size of the Eastern Australian labour market, this is a significant increase.

10 THE WAY FORWARD: MAINTAINING THE WEST–EAST PIPELINE OPTION

Real options approaches to decision making involve maintaining a set of alternative decision pathways that allow flexible adjustments to changing circumstances. There are costs associated with establishing and maintaining each option, but the investment is justified by the opportunity to lower the risk of incurring high costs because of premature lock-in to irreversible decisions that prove to be sub-optimal.

Real options approaches are particularly valuable for decision making under conditions of uncertainty, because they provide decision-makers with flexibility to adjust their positions as new information comes to hand.

A sensible real options approach to dealing with the longer-term issue of security of gas supply for the Eastern Australian market would include maintaining the option to proceed, or not to proceed, with the West-East Pipeline at a future date by undertaking prudent low-cost monitoring and preparatory activities. Such activities would advance the project and help to reduce its delivery timeframe, while deferring any commitment to major capital expenditure unless and until it becomes clear that the West–East Pipeline has emerged as a necessary and commercially robust solution.

Some of the early, low cost activities that might be undertaken include:

- careful monitoring of progress of alternatives
- identification of potential gas supply sources and the technical and commercial requirements for their delivery
- testing of customer interest in purchasing gas from the project and the commercial terms on which such sales might be transacted
- pipeline route investigations aimed at optimising the pipeline corridor and better identifying important physical, environmental, heritage and socio-economic constraints and opportunities
- establishing baseline environmental monitoring along the pipeline corridor
- preliminary community and stakeholder consultation in potentially affected areas
- steps to secure and maintain access to the pipeline corridor
- consideration of possible models of ownership structures
- consideration of alternative funding models.

In considering what should be done now to progress the West–East Pipeline option, some important questions arise:

- Who should plan, execute and fund any further work?
- What should be the respective roles of government and industry stakeholders in maintaining the option to develop the West–East Pipeline?
- How should activities be co-ordinated?

Answering these questions requires consideration of the respective roles of government and commercial organisations and how those roles might change over time, as well as the basis on which the activities of various stakeholders should be co-ordinated.

There are several possible models for establishing a co-ordination framework through which roles can be identified and plans of action agreed. At a high level, there are three basic designs for such a framework:

1. **Government-led:** work is undertaken principally by a government committee or working group involving representatives of Commonwealth and relevant State/Territory Governments. This could be arranged, for example, through the existing Gas Major Projects Implementation Team (GMPIT) or via a special purpose committee or working group established through the COAG Energy Council. The government-led working group could be supported by an Industry Advisory Committee.

   Under this model, consideration should be given to the scope of issues dealt with by the working group:

   a) narrow focussed, for example a West–East Pipeline Working Group
   b) more broadly focussed, for example a National Gas Infrastructure Co-ordination Group
   c) widely focussed, for example a Gas Supply Security Working Group.

2. **Government-convened, industry led:** work is undertaken in a 'roundtable' or periodical forum format. The South Australian Roundtable for Oil & Gas is an example of this model.

   Such an approach would most likely be successful if focussed broadly—for example a National Gas Supply Security Roundtable—rather than by adopting a narrow focus on the West–East Pipeline, which would be likely to attract much narrower participation.

   The role of such a roundtable or forum would be to facilitate development of industry-led, commercial solutions to improving gas supply security. Multiple working groups could be established, addressing different aspects of gas supply security.

   Working Groups could be identified and prioritised through a 'road-mapping' exercise, for example development of a 'National Gas Supply Security Roadmap'.

   A West–East Pipeline Working Group could be tasked with developing and executing a program of activities aimed advancing the West–East Pipeline concept and helping to reduce its delivery timeframe. Other work streams could address issues such as Promoting New Gas Supply, Gas Storage, Unconventional Gas, and so forth.

   Membership would be open to all interested organisations. Participants would self-nominate to individual work streams.

   Member organisations would meet their own costs of participation. Commissioned activities (for example, the West–East Pipeline Working Group commissioning more detailed route investigations) could be funded under a Commonwealth/State/Industry funding agreement providing a budget for commissioned activities, allocated through an application/award process overseen by a Research Steering Committee.

3. **Industry-led:** under this model the Commonwealth Government would call for expressions of interest or run a competitive tender process seeking proposals from commercial organisations or consortia to progressing the West–East Pipeline. This process would lead to selection of an organisation or consortium as 'Preferred Developer'. The Northern Territory Government's process for soliciting industry involvement in the construction of a Northern Territory – Eastern Australia Gas Interconnector (NEGI) is an example of this model.

   Such an approach would effectively encourage industry players (producers, pipeliners, gas users) to come together of their own volition to pursue the West–East Pipeline concept on a commercial basis.

   Depending on timing, the Commonwealth Government could mandate more than one consortium to progress the concept. Early on, it may be feasible to mandate multiple consortia, with a view to narrowing the field to a single Preferred Developer if the project firms up as a feasible and desirable option.

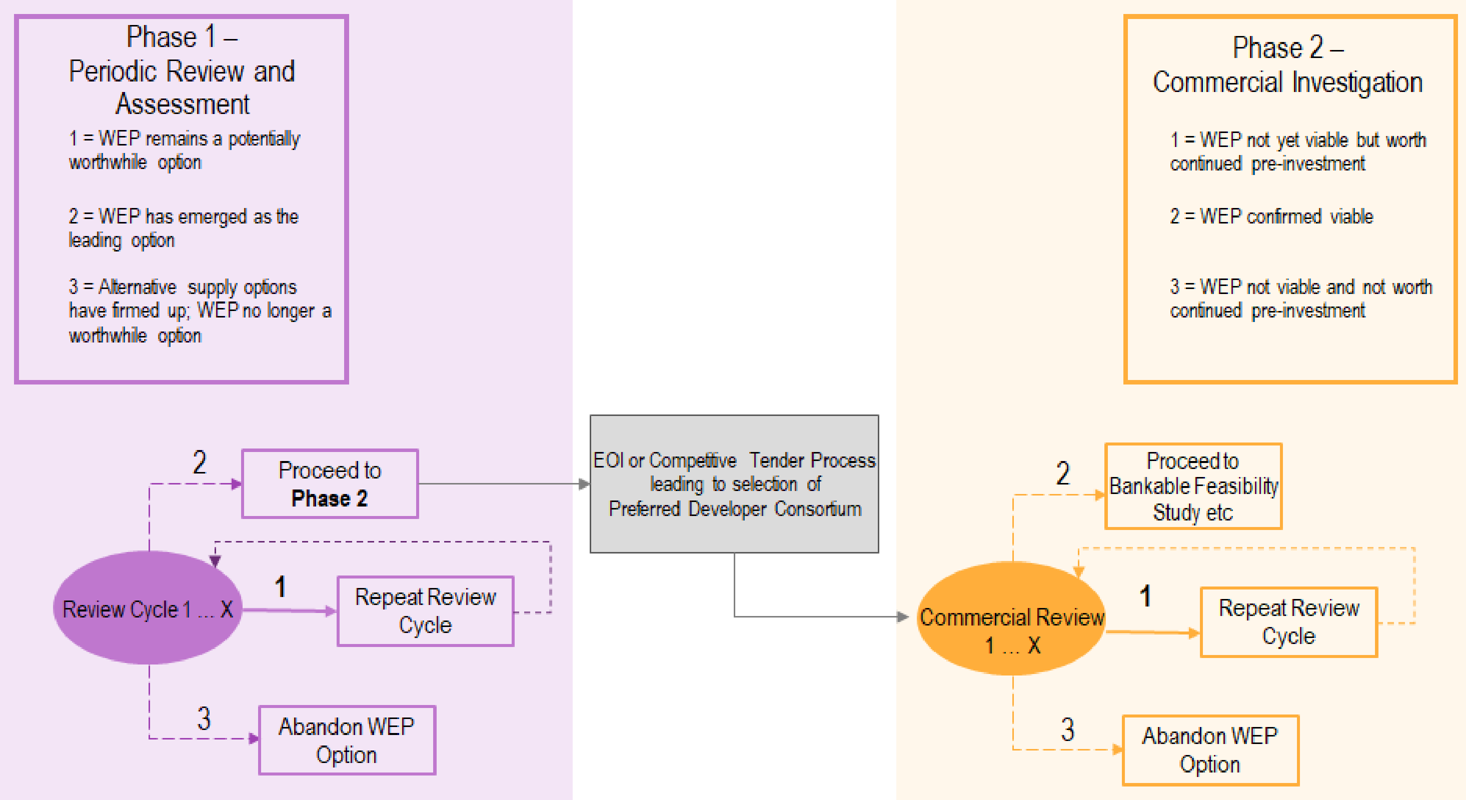
The selected Developer/s could be required to provide regular formal updates to Government on plans, activities, progress and prospects for development.

There is, of course, a risk under this model that, at the time when expressions of interest are called, no commercial Developer would be prepared to pursue the project. Such an outcome would provide a clear reading on industry views regarding the then-current commercial prospects for the project.

10.1.1 A phased, gated approach

Consistent with a real options decision-making paradigm, a 'phased, gated approach' is proposed to progress the West–East Pipeline concept. This decision process is summarised in **Figure 10.1**.

FIGURE 10.1 PHASED, GATED DECISION PROCESS FOR PROGRESSING THE WEST–EAST PIPELINE



SOURCE: ACIL ALLEN CONSULTING

Phase 1 would involve a process of monitoring and periodic review of the West–East Pipeline's prospects as a commercially feasible and desirable option for bolstering east coast gas supply. This process would best be undertaken by a government committee or working group involving representatives of Commonwealth and relevant State/Territory Governments (see Co-ordination Framework Design 1 above). Each review would include an assessment of progress on other east coast gas supply options allowing conclusions to be drawn whether a West–East Pipeline had become more or less prospective since the previous assessment. The conclusion of each review cycle would involve passing a 'decision gate' with three options:

1. Continue to monitor and repeat the review cycle, on the basis that the West–East Pipeline remains a potentially worthwhile option, but has not yet emerged as a solution likely to be commercially viable and financeable; or
2. Proceed to Phase 2, on the basis that the West–East Pipeline has emerged as a valuable solution likely to be commercially viable and financeable; or
3. Abandon the West–East Pipeline option and discontinue monitoring activities, on the basis that the pipeline is no longer considered to be a worthwhile option and would be unlikely ever to be commercially viable and financeable.

Phase 2 would involve commercial investigation by a mandated organisation or consortium of gas producer, pipeliner and/or gas consumer organisations ('Preferred Developer'), selected following an expression of interest or competitive tender process (see Co-ordination Framework Design 3 above).

The Preferred Developer would progress feasibility investigations on a commercial basis. It would periodically assess progress and report to the Government on the results of investigations, leading in each case to a 'decision gate' with three options:

1. Continue to progress the project, without pushing to a final investment decision, on the basis that the West–East Pipeline remains a potentially worthwhile option justifying continued pre-investment; or
2. Proceed to a full Bankable Feasibility Study and Final Investment Decision, on the basis that the West–East Pipeline now has a high probability of being able to proceed as a commercially viable and financeable project; or
3. Abandon the West–East Pipeline option and cease further expenditure, on the basis that it has become unlikely that the pipeline will ever be commercially viable or financeable.

A STAKEHOLDER CONSULTATION: KEY QUESTIONS

A.1 Key questions

The following provides a non-exhaustive list of key questions that we would like to explore through the consultation process.

A.1.1 Sources of gas supply

Does Western Australia have sufficient gas reserves to be able to provide supply to eastern Australia, while still meeting Western Australia's current and future gas requirements for domestic and export use?

What source or sources of gas are or could be made available to supply gas from Western Australia to the eastern States via a West – East Pipeline?

What are the relative advantages and disadvantages of the various gas supply options?

Would the development of a West – East Pipeline be likely to impact (negatively or positively) on the future supply of gas for LNG production in WA?

Would opening up access via pipeline to the east coast market trigger new production opportunities that would also benefit competition/ domestic supply in WA by increasing overall supply?

Broadly speaking, under what sort of commercial terms do you expect that gas could be made available for sale via a West – East Pipeline?

Specifically, what sort of pricing principles do you expect might apply to any such sale of gas?

A.1.2 Pipeline route options

What are the key considerations with regard to selection of potential pipeline routes for a West – East Pipeline?

What point or points of interconnection with the east coast gas transmission system should be considered in evaluating pipeline route options?

Are there any particular considerations influencing the relative attractiveness of different delivery point options?

What would be the relative advantages and disadvantages of the various interconnection point alternatives?

Are there any mid-line gas supply or demand opportunities that should be taken into consideration in evaluating pipeline route options?

Are there any high level land use, environmental or other constraints that should be taken into consideration in evaluating pipeline route options?

Is there likely to be a requirement for additional capital investment in the east coast gas transmission system, beyond the interconnection points, in order to deliver gas to customers in the eastern states?

A.1.3 Gas demand and prices

Who would be the wholesale buyers of WA gas delivered via the West – East Pipeline?

How much WA gas would those buyers be likely take, and over what time frame?

How, if at all, would a market response to the proposed National Energy Guarantee (NEG) be likely to influence future gas demand and prices?

What indicative delivered price would be required at the interconnection point/s with the east coast gas transmission system in order for WA gas delivered via the West – East Pipeline to be seen as a competitive supply option?

Are there any particular risks or opportunities associated with long term gas demand and prices that would be relevant to a decision to invest in a West – East Pipeline?

A.1.4 Market effects

How would construction of a West – East Pipeline be likely to impact on the WA gas market? Are there any particular benefits or risks that should be taken into account?

How would construction of a West – East Pipeline be likely to impact on the eastern states gas markets? Again, are there any particular benefits or risks that should be taken into account?

Is the current WA government policy on hydraulic fracture stimulation of petroleum reservoirs likely to have any implications for a West – East Pipeline, or for the likely impacts of such a pipeline on the WA gas market? If so, how?

A.1.5 Other matters

Are there any other matters that the Study Team should take into account in the course of the pre-feasibility study?

B

GASMARK MODEL

GasMark Global (GMG) is a generic gas modelling platform developed by ACIL Allen. GMG has the flexibility to represent the unique characteristics of gas markets across the globe, including both pipeline gas and LNG. Its potential applications cover a broad scope — from global LNG trade, through to intra-country and regional market analysis. *GasMark* is an Australian version of the model which focuses specifically on the Australian market (including both Eastern Australian and Western Australian modules), but which has the capacity to interface with international LNG markets.

B.1 Settlement

At its core, *GasMark* is a partial spatial equilibrium model. The market is represented by a collection of spatially related nodal objects (supply sources, demand points, LNG liquefaction and receiving facilities), connected via a network of pipeline or LNG shipping elements (in a similar fashion to 'arks' within a network model).

The equilibrium solution of the model is found through application of linear programming techniques which seek to maximise the sum of producer and consumer surplus across the entire market simultaneously. The objective function of this solution, which is well established in economic theory[22], consists of three terms:

- the integral of the demand price function over demand; minus
- the integral of the supply price function over supply; minus
- the sum of the transportation, conversion and storage costs.

The solution results in an economically efficient system where lower cost sources of supply are utilised before more expensive sources and end-users who have higher willingness to pay are served before those who are less willing to pay. Through the process of maximising producer and consumer surplus, transportation costs are minimised and spatial arbitrage opportunities are eliminated. Each market is cleared with a single competitive price.

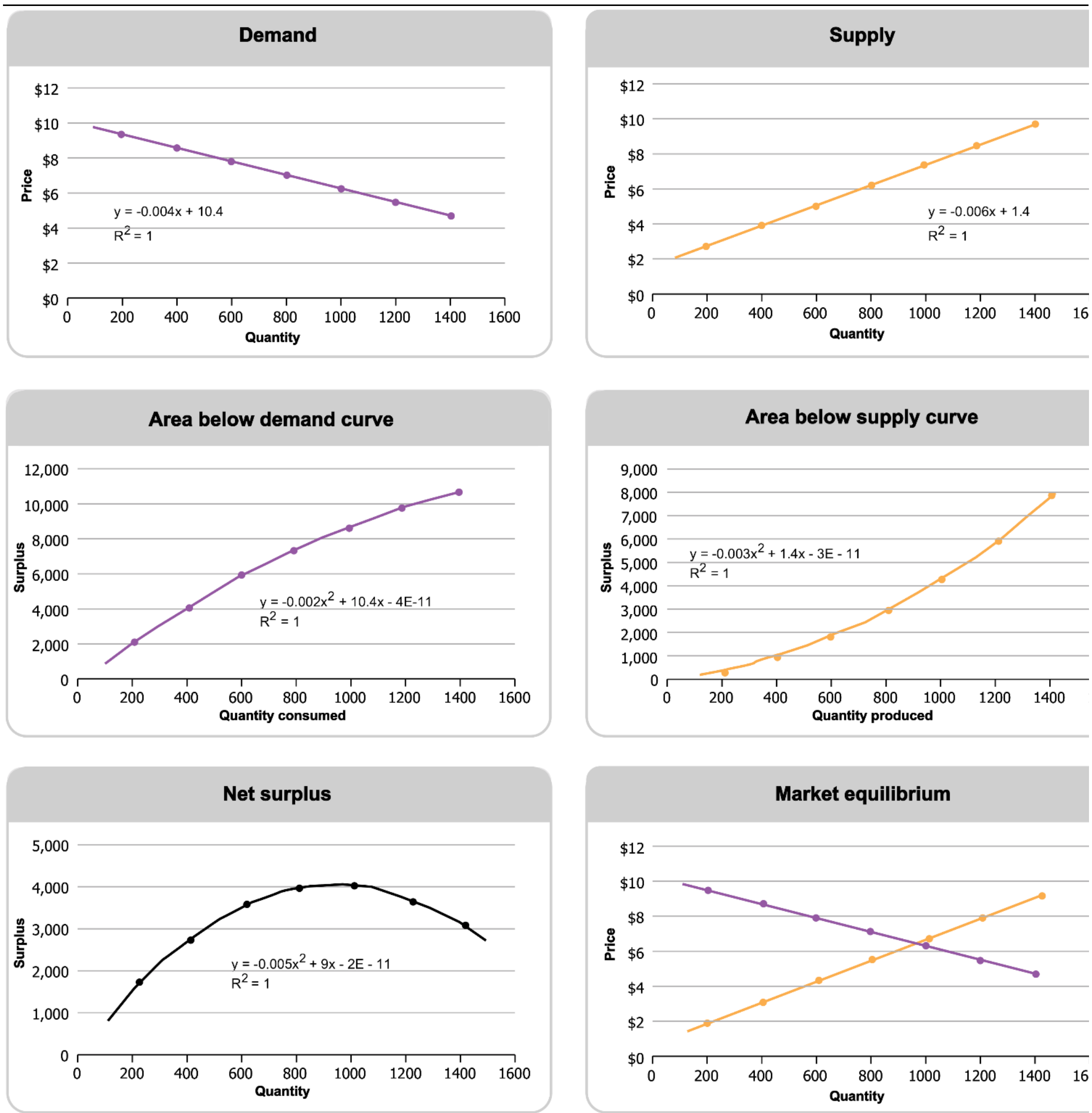
Figure B.1seeks to explain diagrammatically a simplified example of the optimisation process. The two charts at the top of **Figure B.1** show simple linear demand and supply functions for a particular market. The figures in the middle of **Figure B.1** show the integrals of these demand and supply functions, which represent the areas under the demand and supply curves. These are equivalent to the consumer and producer surpluses at each price point along the curve. The figure on the bottom left shows the summation of the consumer and producer surplus, with a maximum clearly evident at a quantity of 900 units. This is equivalent to the equilibrium quantity when demand and supply curves are overlayed as shown in the bottom right figure.

22 The theoretical framework for the market solution used in *GasMark* is attributed to Nobel Prize winning economist Paul Samuelson.

The distinguishing characteristic of spatial price equilibrium models lies in their recognition of the importance of space and transportation costs associated with transporting a commodity from a supply source to a demand centre. Since gas markets are interlinked by a complex series of transportation paths (pipelines, shipping paths) with distinct pricing structures (fixed, zonal or distance based), *GasMark* also includes a detailed network model with these features.

Spatial price equilibrium models have been used to study problems in a number of fields including agriculture, energy markets, mineral economics, as well as in finance. These perfectly competitive partial equilibrium models assume that there are many producers and consumers involved in the production and consumption, respectively, of one or more commodities and that as a result the market settles in an economically efficient fashion. Similar approaches are used within gas market models across the world.

FIGURE B.1 SIMPLIFIED EXAMPLE OF MARKET EQUILIBRIUM AND SETTLEMENT PROCESS



SOURCE: ACIL ALLEN CONSULTING

B.2 Data inputs

Data inputs to *GasMark* are made via a map-based graphical user interface which allows easy visualisation of the relationships between gas reserves and production sources, pipelines and demand centres including market nodes and LNG production facilities. Data is stored in Microsoft® Access® databases that operate in the background.

The user can establish the level of detail by defining a set of supply regions, customers, demand regions, pipelines and LNG facilities. These sets of basic entities in the model can be very detailed or aggregated as best suits the objectives of the user. A 'pipeline' could represent an actual pipeline or a pipeline corridor between a supply and a demand region. A supplier could be a whole gas production basin aggregating the output of many individual fields, or could be a specific producer in a smaller region. Similarly a demand point could be a single industrial user or an aggregation of small consumers such as the residential and commercial users typically serviced by energy utility companies.

The inputs to *GasMark* can be categorised as follows:

— **Existing and potential new sources of gas supply**: these are characterised by assumptions about available reserves, production rates, production decline characteristics, and minimum price expectations of the producer. These price expectations may be based on long-run marginal costs of production or on market expectations, including producer's understandings of substitute prices.

— **Existing and potential new gas demand**: demand may relate to a specific load such as a power station, or fertiliser plant. Alternatively it may relate to a group or aggregation of customers, such as the residential or commercial utility load in a particular region or location. Loads are defined in terms of their location, annual and daily gas demand including daily demand profiles, and price tolerance.

— **Existing, new and expanded transmission pipeline capacity**: pipelines are represented in terms of their geographic location, physical capacity (which may vary over time), flow characteristics (uni-directional or bi-directional) and tariffs.

— **Existing and potential new LNG facilities**: LNG facilities include liquefaction plants, regasification (receiving) terminals and assumptions regarding shipping costs and routes. LNG facilities play a similar role to pipelines in that they link supply sources with demand. LNG plants and terminals are defined at the plant level and require assumptions with regard to annual throughput capacity and tariffs for conversion.

B.3 Model outputs

GasMark generates standardised output files including:

— **Gas production** over time by field, field type, production region, State and operator

— **Gas consumption** over time by market, load, load type, consumption region and State

— **Gas prices** over time, on a wholesale delivered basis, by market location

— **Gas pipeline flows** over time, by pipeline segment

— **LNG liquefaction plant shipments** by terminal and State.

Results can be routinely generated on a monthly, quarterly or annual basis.

C

MULTI-CRITERIA ANALYSIS

The Multi-Criteria Analysis (MCA) criteria and data sources are summarised in **Table C.1**.

TABLE C.1 MCA ANALYSIS CRITERIA AND DATA SOURCES

Theme	Criteria	Data Source	Justification for Inclusion/Exclusion	Measure	Score	Score Meaning
Infrastructure	Road Network	WA - Landgate Roads SA - DoPTI Roads NT - Geoscience Australia	Preferable to be close to existing roads to facilitate easier access for construction. Low weight.	within 1km	1	No Constraints
				1 km - 10 km	10	Low Constraints
				10 km +	20	Some Constraints
				N/A	40	Highly Constrained
				N/A	999	Not Feasible
	Rail Network	Geoscience Australia	Preferable to be close to existing rail to facilitate easier access for construction. Low weight.	within 1km	1	No Constraints
				1 km - 10 km	10	Low Constraints
				10 km +	20	Some Constraints
				N/A	40	Highly Constrained
				N/A	999	Not Feasible
	High voltage major Powerlines	Geoscience Australia - Transmission Overhead Powerlines Western Power - Distribution Overhead Powerlines (SW Only)	Preferable to avoid disruption to existing powerlines. Low weight.	Outside 500m	1	No Constraints
				N/A	10	Low Constraints
				N/A	20	Some Constraints
				within 500m	40	Highly Constrained
				N/A	999	Not Feasible
	Proposed and Major Mines	NT - Mining Lease Boundaries (DoPIR) WA - Mining Tenements (DMP) SA - Extractive Mineral Lease, Mineral Claims, Mineral Leases,	Must avoid existing mine areas. Preferable to avoid proposed mine areas. Low weight.	Outside existing and proposed mine areas	1	No Constraints
				N/A	10	Low Constraints
				Crossing proposed mine area	20	Some Constraints
				N/A	40	Highly Constrained
				Crossing existing mine area	999	Not Feasible
	Pipelines	WA, SA, NT - National Onshore Gas Pipelines Database (GA) WA, SA, NT - National Onshore Oil Pipelines (GA)	Preferable to be close to existing pipelines to leverage existing infrastructure or easements. Medium weight.	within 1km	1	No Constraints
				1 km - 10 km	10	Low Constraints
				10 km +	20	Some Constraints
				N/A	40	Highly Constrained
				N/A	999	Not Feasible

Theme	Criteria	Data Source	Justification for Inclusion/Exclusion	Measure	Score	Score Meaning
Environment	Native Vegetation	WA, SA, NT - Native Vegetation Areas (GA)	Important to avoid significant areas of native vegation. High weight.	Outside 1000m	1	No Constraints
				Within 500m - 1000m	10	Low Constraints
				Within 500m	20	Some Constraints
				Intersects	40	Highly Constrained
				N/A	999	Not Feasible
	Acid Sulfate Soils	WA, SA, NT - Atlas of Australian Acid Sulfate Soils (CSIRO)	Preferable to avoid areas of high probability for acid sulfate soils due to contamination risk and remediation cost. Low weight.	Else	1	No Constraints
				Extremely Low Probability	10	Low Constraints
				Low Probability	20	Some Constraints
				High Probability	40	Highly Constrained
				N/A	999	Not Feasible
	Ramsar Wetlands	WA, SA, NT - Ramsar Wetlands of Australia (DoE)	Must avoid declared RAMSAR wetlands to avoid any damage to sensitive habitat. High weight.	Outside	1	No Constraints
				N/A	10	Low Constraints
				N/A	20	Some Constraints
				N/A	40	Highly Constrained
				Intersect	999	Not Feasible
	National and State Parks	Collaborative Australian Protected Areas - DOEE	Must avoid National Parks, and should avoid State Parks if possible. High weight.	Else 1	1	No Constraints
				N/A	10	Low Constraints
				N/A	20	Some Constraints
				State Parks (all other land types)	40	Highly Constrained
				National Parks	999	Not Feasible
	Environmentally Sensitive Areas	WA - Environmentally Sensitive Areas NT - Sites of Botanical Significance NT - Sites of Conservation Significance	Important to avoid environmentally sensitive areas to avoid any damage to sensitive ecosystems. High weight.	Outside 1000m	1	No Constraints
				Within 500m - 1000m	10	Low Constraints
				Within 500m	20	Some Constraints
				Intersects	40	Highly Constrained
				N/A	999	Not Feasible
Social	Registed European Heritage (state and federal)	National - National Heritage List Spatial Database WA - Heritage Council State Register SA - Heritage Places NT - N/A	Must avoid existing listed European Heritage sites. High weighting	Outside	1	No Constraints
				N/A	10	Low Constraints
				N/A	20	Some Constraints
				N/A	40	Highly Constrained
				Within	999	Not Feasible
	Existing and Future Agricultural Use	Catchment Scale Land Use of Australia - Commodities - September 2017 (DoAWR) http://data.daff.gov.au/anrdl/metadata_files/pb_clsucd9aal20171114_11a.xml - Grazing native vegetation - Grazing modified pastures	Important to avoid existing agricultural land. Medium weighting.	Outside	1	No Constraints
				N/A	10	Low Constraints
				N/A	20	Some Constraints
				Within	40	Highly Constrained
				N/A	999	Not Feasible
	Urban/Populated Areas	WA, SA, NT - Urban Centre and Locality Boundaries	Must avoid dense urban areas. Medium-high weighting	More than 5 Km from highly dense urban areas	1	No Constraints
				N/A	10	Low Constraints
				Within 5km of highly dense urban areas	20	Some Constraints
				N/A	40	Highly Constrained
				Intersects with highly dense urban areas	999	Not Feasible
	Military Sites	WA, SA, NT - Prohibited Areas (GA)	Must avoid military sites. High weighting	Outside	1	No Constraints
				N/A	10	Low Constraints
				N/A	20	Some Constraints
				N/A	40	Highly Constrained
				Within	999	Not Feasible
Physical	Water Body	WA, SA, NT - Waterbodies (GA)	Avoid costly crossings of known water bodies. Medium-high weight.	Greater than 5 km from water body	1	No Constraints
				Between 2 and 5 km from water body	10	Low Constraints
				Between 1 and 2 km from water body	20	Some Constraints
				Less than 1 km from water body	40	Highly Constrained
				Crossing	999	Not Feasible
	Water Course	WA, SA, NT - Watercourses (GA)	Avoid costly crossings of known water courses. Medium weight.	Greater than 5 km from watercourse	1	No Constraints
				Between 2 and 5 km from watercourse	10	Low Constraints
				Between 1 and 2 km from watercourse	20	Some Constraints
				Less than 1km	40	Highly Constrained
				N/A	999	Not Feasible
	Slope	Geoscience Australia	Avoid running pipeline through highly variable or steep terrain. Medium weight.	0 - 1	1	No Constraints
				1 - 3%	10	Low Constraints
				3 - 5 %	20	Some Constraints
				5 - 10%	40	Highly Constrained
				10% +	999	Not Feasible

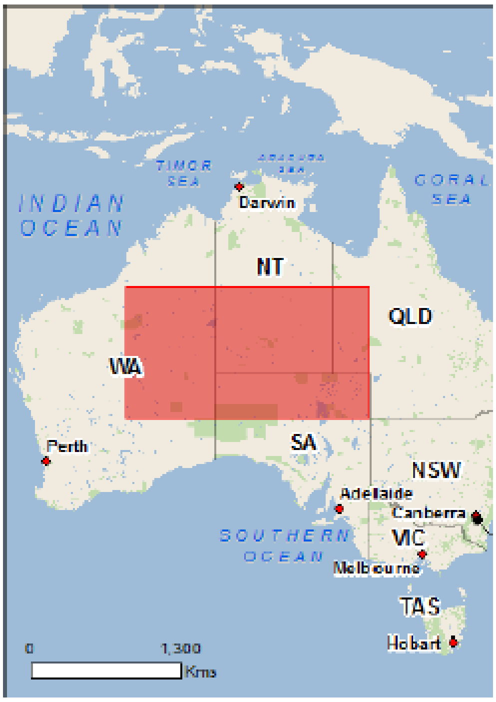
D

EPBC ACT PROTECTED MATTERS

A separate report has been generated summarising the matters of national environmental significance that may occur in, or may relate to, the area shown in **Figure D.1**.

This report was generated using the on-line EPBC Act Protected Matters Tool, available on the website of the Department of Environment and Energy.

FIGURE D.1 AREA COVERED BY EPBC ACT PROTECTED MATTERS REPORT



SOURCE: AUSTRALIAN GOVERNMENT, DEPARTMENT OF ENVIRONMENT AND ENERGY

E

NORTHERN TERRITORY ENVIRONMENTAL APPROVAL PROCESS

TABLE 10.1 NORTHERN TERRITORY ENVIRONMENTAL APPROVAL FOR PER LEVEL OF ASSESSMENT

Action	Timing
Proponent notifies the responsible Minister of the proposed action.	Open
Responsible Minister notifies the NT EPA of the proposed action.	Open
NT EPA may require further information from proponent to assist in determining the level of environmental significance of the proposed action.	Within 14 days
NT EPA determines the level of assessment and notifies the Minister and proponent that a PER is necessary.	Open
There may be a requirement for Australian Government input on type and level of assessment under the Environment Protection and Biodiversity Conservation Act 1999 (EPBC Act). If the proposed action is determined to be a controlled action, it is likely to be assessed under the bilateral agreement between the NT and Australian Governments.	
Draft Terms of Reference for the preparation of a PER are prepared by the NT EPA.	Open
Draft Terms of Reference available for public and advisory body comment.	Within 14 days* ** Timeline will be determined by the NT EPA and the Australian Government if the assessment is under the bilateral agreement.*
NT EPA finalises draft Terms of Reference, issues Terms of Reference to the proponent and directs the preparation of a PER.	Within 14 days
Proponent prepares PER and submits to the NT EPA (and Australian Government if PER bilateral).	Open
PER open for public and advisory body exhibition and comment.	Within 28 days* **Timeline will be determined by the NT EPA and the Australian Government if the assessment is under the bilateral agreement.*

Action	Timing
NT EPA can request further information during the exhibition period. If further information is requested, the assessment clock stops until the information is received.	
If PER is undertaken under an agreement between the NT and Australian Governments, the public and advisory body comments are forwarded to the proponent. The proponent prepares a Supplement to the PER and submits it to the NT EPA. *The NT EPA can request further information after Supplement submitted. Assessment clock stops until the information is received.*	
NT EPA prepares the assessment report and recommendation based on PER and further information, if requested. NT EPA provides assessment report to the Minister.	Within 14 days of expiration of the exhibition period or further information submission* **Within 28 days of Supplement delivery or further information submission if the assessment is under the bilateral agreement*
NT EPA provides the assessment report to the Australian Government for consideration under the EPBC Act, if the assessment is under the bilateral agreement.	

SOURCE: GHD

TABLE 10.2 NORTHERN TERRITORY ENVIRONMENTAL APPROVAL FOR EIS LEVEL OF ASSESSMENT

Action	Timing
Proponent notifies the responsible Minister of the proposed action.	Open
Responsible Minister notifies the NT EPA of the proposed action.	Open
NT EPA may require further information from proponent to assist in determining the level of environmental significance of the proposed action.	Within 14 days
NT EPA determines the level of assessment and notifies the Minister and proponent that an EIS is required.	Open
There may be a requirement for Australian Government input on type and level of assessment under the Environment Protection and Biodiversity Conservation Act 1999 (EPBC Act). If the proposed action is determined to be a controlled action, it is likely to be assessed under the bilateral agreement between the NT and Australian Governments.	
Draft Terms of Reference for the preparation of an EIS are prepared by the NT EPA.	Open
Draft Terms of Reference available for public comment and referred to advisory bodies.	Within 14 days*.
NT EPA finalises draft Terms of Reference, issues Terms of Reference to the proponent and directs the preparation of an EIS.	Within 14 days
Proponent prepares draft EIS and submits to the NT EPA.	Open (unless specified by NT EPA)
Draft EIS open for public and advisory body exhibition and comment.	Not less than 28 days
Public and advisory body comments forwarded to proponent.	ASAP

Action	Timing
Proponent prepares Supplement to draft EIS and submits Supplement to NT EPA (date can be determined by the NT EPA)..	Open
Supplement to draft EIS circulated to advisory bodies for comment.	Within 14 days
NT EPA can request further information. *If further information is requested, the assessment clock stops until the information is received.*	Within 21 days of Supplement received
NT EPA prepares the assessment report based on draft EIS, Supplement and comments received (NT EPA can extend period). NT EPA provides assessment report to the Minister.	Within 35 days of Supplement or further information receipt
NT EPA provides the assessment report to the Australian Government for consideration under the EPBC Act, if the NT EPA undertakes the assessment on behalf of the Australian Government.	Open

SOURCE: GHD

F

RISK EVALUATION CRITERIA

F.1 Risk evaluation criteria

TABLE F.1 RISK EVALUATION CRITERIA

Consequence Table				
		Severity		
Consequence	**Notes**	**S1 - Low**	**S2 - Moderate**	**S3 - High**
Safety	Impact on public safety	Minor injuries requiring medical attention and /or multiple first aid cases	1 - 5 serious injuries and/or multiple medical treatment cases (hospitalisation)	5+ serious injuries and / or 1+ irreversible injury / fatality
Financial	CAPEX	<5% Exceedance	5% - 30% Exceedance	>30% Exceedance
	OPEX	<5% Exceedance	5% - 30% Exceedance	>30% Exceedance
	REVENUE	<5% Exceedance	5% - 30% Exceedance	>30% Exceedance
Project Schedule	Impact on project delivery	<6 months delay	6 months - 12 months delay	> 12 months delay
Reputation / Political	Impact on principal organisation	Limited adverse local media	Negative state media coverage.	Negative national media coverage
Legal / Contractual	Impact on principal organisation	Minor legal issues, non-compliance breaches or regulation Minor contractual issue, resolved through negotiation	Minor legal issues, non-compliance and breaches of regulation with investigation, minor litigation Moderate contractual issue, requiring some litigation	Serious breach of regulation with prosecution / fines, moderate litigation Serious contractual issue, requiring extensive litigation
Engineering / Technical	Impact on project delivery	Minor reduction in performance or technical compliance. Only minor	Moderate reduction in performance or technical compliance. Some key	Significant degradation in performance / technical compliance.

		requirements not met. Waivers will likely be granted to resolve.	requirements not met. Some waivers may be granted. May require the project to be re-scoped	Key but non-critical requirements not met. Waivers unlikely to be granted in all cases, requiring project to be re-scoped.
Community / Stakeholder	Impact on principal organisation	Short term loss of trust with communities, repaired within days Stakeholder actions resulting in operational or commercial impacts equivalent in value to days to weeks of reduced benefit	Loss of trust with communities that cannot be resolved through routine procedures. Disruptive organised opposition Stakeholder actions resulting in operational or commercial impacts equivalent in value to days to weeks of lost benefit	Widespread, sustained opposition from communities Stakeholder actions resulting in operational or commercial impacts equivalent in value to weeks to months of lost benefit
Environment / Heritage	Impact on external environment	Short term effects (weeks) within area of limited environmental / heritage significance	Medium term effects (months) in an area of some environmental / heritage significance as identified by external government authorities	Long term (years) / permanent environmental impairment in an area of high environmental / heritage significance as identified by external government authorities

Likelihood Table

		Label	Frequency	Probability
Likelihood	F1	Unlikely	Occurs from time to time (1 in 20 years)	<5% chance of occurring during the project
	F2	Possible	Could occur once in next 5 years	5% - 50% chance of occurring during the project
	F3	Likely	Could occur >10 times in next 5 years , daily to monthly (>2 per year)	>50% chance of occurring during the project

Risk Matrix

		Severity		
		Low	**Moderate**	**High**
Frequency / Probability	**Likely**	**Moderate**	**High**	**High**
	Possible	**Low**	**Moderate**	**High**
	Unlikely	**Low**	**Low**	**Moderate**

F.2 Risk register

F.2.1 Initial risk rating

Risk Type	Risk / Opportunity [Brief name for risk/opp]	Risk / opp description [Outline of what could happen]	Key impact analysis [Provide brief basis for the magnitude of the consequence/opportunity]	Evaluation Rationale [Record why the risk has been evaluated at the level shown to the right]	Likelihood [Based on currently known data and no new mitigation]	Consequence [Based on currently known data and no new mitigation]	Initial Risk Rating (IRR)
Routing							
Threat	Options selection process	The options selection process identifies an unsuitable route for the pipeline	The unsuitable route selection results in major pipeline re-routing costs and project schedule delays, leading to exceedance of project CAPEX and delay in project delivery. Worst case is the market opportunity for sales gas is lost and the project becomes unviable.	Evaluated as a >30% CAPEX exceedance based on having to reroute the pipeline, potentially having to seek new approvals and loss of gas sales revenue	Possible	High	High
Threat	InDeGO Route selection software	The InDeGO route selection software has incorrect or incomplete parameter settings	A non-optimum pipeline route is selected, resulting in moderate re-routing costs and some delays in schedule. May require some re-negotiation of approvals with landowners and delays in approvals. Stakeholder concerns raised about the project which will incur costs and some impact on reputation.	Evaluated as a 5% - 30% CAPEX exceedance, and some negative state media coverage	Possible	Moderate	Moderate
Threat	Changed route selection criteria	The route selection criteria are changed or modified during the course of the project	Changes in route selection criteria that impose further restrictions on suitability of chosen route could lead to significant revisions to engineering and CAPEX.	Evaluated as a 5% - 30% CAPEX exceedance	Possible	Moderate	Moderate
Threat	Pipeline access is restricted	The pipeline route selected has inaccessible sections for construction and operation	The selected route may have sections that are not accessible for construction or operational maintenance. Revising route likely to result in additional CAPEX.	Evaluated as less than 5% CAPEX exceedance based on having to locally reroute the pipeline to continue construction.	Possible	Low	Low
Opportunity	Intermediate gas supplies / offtakes identified	Possible suppliers or offtakes of gas along route identified	Identification of additional input or offtake points along route for gas may lead to route revisions but could improve economics.	Evaluated as a <5% increase in revenue that would be achieved	Possible	Low	Low

Risk Type	Risk / Opportunity [Brief name for risk/opp]	Risk / opp description [Outline of what could happen]	Key impact analysis [Provide brief basis for the magnitude of the consequence/opportunity]	Evaluation Rationale [Record why the risk has been evaluated at the level shown to the right]	Likelihood [Based on currently known data and no new mitigation]	Consequence [Based on currently known data and no new mitigation]	Initial Risk Rating (IRR)
Design, Construction & Delivery							
Threat	Construction contract	A construction contract fails to be awarded	Tender negotiations with preferred contractor fail. Negotiation with next contractor could delay project and would result in increased costs.	Evaluated as a >30% CAPEX exceedance based on having to negotiate with additional contractor with potential project delays and loss of gas sales revenue, negative media coverage	Unlikely	High	Moderate
Threat	Construction contractor	The construction contractor fails to complete the construction contract (e.g. contractual dispute, insolvency)	Construction contractor tenders not acceptable due to critical conditions; conditions precedent can not be met; contractor cannot obtain finance; contractor becomes insolvent; contractual dispute; etc. causing project delays and possible resumption of the contract and appointment of different contractor to complete the works	Evaluated as a >30% CAPEX exceedance and potential liquidated damages based on having to negotiate with additional contractor with potential project delays (>12 months) and loss of gas sales revenue, negative media coverage	Possible	High	High
Threat	Pipeline design	A suitable pipeline design organisation cannot be appointed, or fails to deliver a design	Negotiations with preferred design firm fail. Negotiation with next preferred firm could delay project and would result in increased costs. Selected design firm under resourced and unable to provide design to support construction contractor schedule. Design firm produces incorrect pipeline specification	Evaluated as a 5%-30% CAPEX exceedance due to construction delays.	Possible	Moderate	Moderate
Threat	Pipeline materials	Sufficient quantities of suitable pipeline materials are unavailable, or can't be delivered during the project delivery timeframe.	Total quantity of pipe may exceed a mill's capacity resulting in delayed deliveries impacting on construction program and subsequent CAPEX exceedance.	Evaluated as a 5% - 30% CAPEX exceedance due to construction delays.	Possible	Moderate	Moderate
Threat	Pipeline route access for construction	Access for pipeline materials to construction site locations is restricted or unsuitable	Inability to get pipeline materials to site in a timely manner can cause overall construction delays resulting in increased costs.	Evaluated as less than 5% CAPEX exceedance based on having to locally reroute delivery of pipeline materials needed to continue construction.	Possible	Low	Low
	Construction conditions	Causes include weather, terrain, rock	Inability to construct due to conditions encountered can cause overall construction delays resulting in increased costs.	Evaluated as 5-30% CAPEX exceedance and 6 - 12 month delay	Likely	Moderate	High
	Industrial Relations		Inconsistent conditions across jurisdictions arising from different EBAs	Evaluated as a <5% CAPEX exceedance due to construction delays (6 -12 months).	Possible	Moderate	Moderate

Risk Type	Risk / Opportunity [Brief name for risk/opp]	Risk / opp description [Outline of what could happen]	Key impact analysis [Provide brief basis for the magnitude of the consequence/opportunity]	Evaluation Rationale [Record why the risk has been evaluated at the level shown to the right]	Likelihood [Based on currently known data and no new mitigation]	Consequence [Based on currently known data and no new mitigation]	Initial Risk Rating (IRR)
Approvals							
Threat	Jurisdictional development approvals	Multi-jurisdictional development approvals are required for the project to proceed, but can't all be obtained	There are numerous approvals required for this project with each state and territory having varying approaches to the approvals process. This makes the cross-jurisdictional approach challenging, particularly in addressing the federal approvals (EPBC Act and Native Title Act).	Evaluated as a project delay of >12 months	Possible	High	High
Threat	EPBC approvals	Multi-jurisdictional EPBC approvals are required for the project to proceed, but can't all be obtained	This project will almost certainly be assessed as a Controlled Action. While it is likely approval would be granted, agreement on the offset arrangements between the proponent and Commonwealth may not be agreed.	Evaluated as a project delay of 6-12 months	Possible	Moderate	Moderate
Threat	Landowner approvals	Land acquisition and access rights for construction can't be negotiated with landowners	Multiple land acquisition and access rights to be obtained, many of which may be challenging where the pipeline route is in the vicinity of mining leases, or other significant regional developments and infrastructure. Worst case is a significant delay to the project and additional CAPEX to provide alternative routes to avoid the restrictions on acquisition and access	Evaluated as a project delay of <6 months,	Possible	Low	Low
Threat	Native Title claims	New Native Title claims on pipeline route prohibit project proceeding	Native Title claims may jeopardise the approval (see matters arising from Jemena project re fracking gas). Clarity on the Sections of the Act that may apply to this project may require legal advice. This may incur significant time delays to the Project.	Evaluated as a project delay of >12 months	Possible	High	High
Threat	Cultural Heritage sites	Sites of significant cultural heritage are identified along the pipeline route, causing re-routing of the pipeline	There is a risk that unknown sites of cultural signficance may be identified during the Arch/ethno investigations. Re-routing has potential time and cost implications to the project. Public protest may arise if cultural sites are not deemed significant enough to warrant re-routing bringing reputational damage to the Project.	Evaluated as a project delay of 6 to 12 months, and a loss of trust with communities that cannot be resolved through routine procedures, potentially leading to disruptive organised opposition	Possible	Moderate	Moderate
Threat	Community / stakeholder opposition to the project	Communities and/or stakeholders withdraw support for the project, leading to public concern about the project progressing	Lack of transparency, regard to environmental approval processes, cultural and natural heritage sensitivities may lead to public lobbying against the project. Political pressure on proponent may result in withdrawal of proponent support for the Project.	Evaluated as a project delay of 6 to 12 months, and a loss of trust that leads to widespread, sustained opposition from communities. Political responses resulting in operational or commercial impacts equivalent in value to weeks to months of lost benefit	Unlikely	Moderate	Low
Threat	Investigations for environmental approval are not well defined	Studies undertaken do not adequately describe the impact	Assessment of the environmental studies may identify signficant gaps in information requiring re-work and re-investigations. This outcome has time and cost implications to the Project.	Evaluated as a project delay of 6 to 12 months	Possible	Moderate	Moderate
Threat	Timeframe for approvals exceeds two years	It is reasonable to assume that approvals will take at least 2 years. Potential investors may reject the opportunity if the timeframe and costs are not managed efficiently.	Insufficient pre-referral meetings with regulators may result in poor scoping of work and scopes of work for field investigations leading to excessive approval timeframes and reputational impact for proponent and possible for proponent to reject the Project.	Evaluated as a project delay of >12 months	Possible	High	High

Risk Type	Risk / Opportunity [Brief name for risk/opp]	Risk / opp description [Outline of what could happen]	Key impact analysis [Provide brief basis for the magnitude of the consequence/opportunity]	Evaluation Rationale [Record why the risk has been evaluated at the level shown to the right]	Likelihood [Based on currently known data and no new mitigation]	Consequence [Based on currently known data and no new mitigation]	Initial Risk Rating (IRR)
Economics							
Threat	Project costing	Lack of robustness in project costing	Poor scoping of the project leads to a significant underestimation of the costs, requiring additional CAPEX. Worst case is that the revised costing makes the project economically unvialbe and the project does not proceed. Reputational damage to the proponent	Evaluated as a>30% exceedance of CAPEX and proponent actions that inhibit any economic returns on the project	Unlikely	High	Moderate
Threat	Project cost overuns	Additional or changed scope of project, causing change in costing basis	Changed scope of the project leads to a significant underestimation of the costs, requiring additional CAPEX.	Evaluated as a >30% exceedance of CAPEX	Possible	High	High
Threat	Currency fluctuations	Sourcing of pipeline materials is subject to international currency exchange rates	The majority of the pipe, fittings, valves, instrumentation and compression equipment will need to be imported. Currency fluctuations can have significant impact on the overall CAPEX.	Evaluated as less than 5% CAPEX exceedance based on using currency hedging for international purchases.	Likely	Low	Moderate
Threat	Operational costs	Increased pipeline operational costs alter economic viability	Pipeline operational costs, including maintenance are underestimated	Evaluated as a <5% OPEX exceedance	Possible	Low	Low
Threat	Under-estimation of project costing	Lack of robustness in project costing could result in pipeline owner committing to tariffs that are too low to provide an adequate return.	If shipping contracts are already finalised there may be no opportunity to adjust tariffs, locking pipeline owner into sub-economic returns. If shipping contracts are under negotiation, higher tariffs may discourage/prevent shippers and gas buyers from signing up.	Cost estimates will be refined over time through feasibility studies and design processes that are well understood. While final costs may well prove to be significantly higher (or lower) than pre-feasibility estimates, proper sequencing of investment decisions and contracting activities should ensure that costings are well understood before irreversible decisions involving large costs are made.	Unlikely	Moderate	Low
Threat	Project cost overuns	Additional or changed scope of project, causing change in costing basis	As above, if shipping contracts are already finalised there may be no opportunity to adjust tariffs, locking pipeline owner into sub-economic returns. If shipping contracts are under negotiation, higher tariffs may discourage/prevent shippers and gas buyers from signing up.	As above. However, overruns may occur because of circumstances that were not anticipated at time of project commitment. This is an execution risk, rather than a planning/design risk, and therefore has a greater probability attaching to it.	Possible	Moderate	Moderate
Threat	Currency fluctuations	Sourcing of pipeline materials and compressors is subject to international currency exchange rates, whereas pipeline revenues will most likely be in Australian dollars.	Adverse currency movements could increase effective costs of construction (in Australian dollar terms). Consequences could be similar to under-estimation of project costs or cost over-runs during construction.	Prior to project commitment, currency fluctuations may adversely affect project economics causing project delays (for example, devaluation of A$ vs US$ could make the project uneconomic until such time as the curreny recovers). Currency risk during construction can be managed by prudent hedging strategies.	Possible	Low	Low

Risk Type	Risk / Opportunity [Brief name for risk/opp]	Risk / opp description [Outline of what could happen]	Key impact analysis [Provide brief basis for the magnitude of the consequence/opportunity]	Evaluation Rationale [Record why the risk has been evaluated at the level shown to the right]	Likelihood [Based on currently known data and no new mitigation]	Consequence [Based on currently known data and no new mitigation]	Initial Risk Rating (IRR)
Economics							
Threat	Operational costs	Increased pipeline operational costs alter economic viability	If operating costs are higher than anticipated, the tariffs charged for the pipeline will be too low to recover all of those costs and the returns to the pipeline owner will be sub-economic.	Technology is mature and well understood. Operating costs should be similarly well understood. For a project like WEP, opex is a small % of total costs.	Unlikely	Low	Low
Threat	Delivered cost of gas too high	Combination of commodity cost of gas (paid to gas producer) and pipeline tariff will determine delivered cost of gas. If too high, gas price will be uncompetitive and there will be insufficient customers.	Too high a delivered cost of gas could result in a lack of sufficient customers, making the pipeline non-viable.	The long transport distance and high capital cost of the WEP project means that the transport component of delivered gas costs are likely to be greater than for gas sourced nearer to EA markets. Achieving competitive delivered gas cost therefore requires that gas feed costs are lower than those of available alternatives. Delivered price will need to be sufficiently attractive to encourage long-term customer commitment.	Likely	High	High
Threat	New pipeline regulations discourage investors	Pipeline owners have expressed concern that recent changes to National Gas Rules will discourage shippers from entering into long-term firm capacity contracts.	Key concerns relate to risks of regulatory coverage, compulsory auctioning of contracted and un-nominated capacity, and information disclosure/arbitration. Directionally these increase risk for pipeliners and contracted shippers, and reduce risk for prospective shippers without existing contracts. If shippers are unwilling to enter into long-term firm contracts for pipe capacity and transport services, pipeline may be unfinancable.	Pipeline owners and their bankers/lenders will need to be satisfied that the commercial basis on which they decide to invest is secure, otherwise they will not invest. Similarly, shippers will not make long term commitments if they think competitors are likely to be able to opportunistically "free ride" on those commitments. The new rules appear to increase risks for investors in new pipelines and for long-term contract shippers.	Possible	High	High
Threat	"Pre-emptive" investment decision	Potential investors in the pipeline - particularly government/s driven by non-commercial objectives - push ahead with project incurring major costs which subsequently turn out to be premature or unjustified.	A pre-emptive decision to build the pipeline could see the investors and underwriters committing very large amounts of money ($ billions) into a project that proves to be underutilised or, in the extreme, entirely stranded. To the extent that Government/s have underwritten the project in oder to 'make it happen' there could be major on-going cost implications (for example, take-or-pay gas offtake & ship-or-pay pipeline capacity commitments that cannot be on-sold).	The risk of pre-emptive or premature investment is likely to increase if there are strong political pressures to demonstrate decisive action to address a perceived problem (in this case, a shortage of gas for domestic users in Eastern Australia). Such risk may be further exacerbated for large infrastructure projects that may be seen as having significant flow-on benefits e.g. for regional development.	Possible	High	High
Opportunity	East Coast energy security	The presence of a new large gas source with a substantial line pack can contribute to both annual and seasonal gas demand	Reduces the risk of gas supply shortages resulting in load curtailment during peak periods including industrial users and power generation	Improved energy supply security, evaluated as reduced economic losses from outages	Unlikely	High	Moderate

GHD

Risk Type	Risk / Opportunity [Brief name for risk/opp]	Risk / opp description [Outline of what could happen]	Key impact analysis [Provide brief basis for the magnitude of the consequence/opportunity]	Evaluation Rationale [Record why the risk has been evaluated at the level shown to the right]	Likelihood [Based on currently known data and no new mitigation]	Consequence [Based on currently known data and no new mitigation]	Initial Risk Rating (IRR)
Commercial & Market							
Threat	Insufficient market demand	In order to keep delivered cost of gas competitive, the pipeline will need to deliver large volumes of gas - potentially around one-third of total EA domestic demand. Insufficient market demand would undermine project economics by driving up the required pipeline tariff, potentially making delivered cost of gas uncompetitive	If market demand is insufficient the project would need to be down-sized, driving up the unit cost of delivered gas and potentially making the gas uncompetitive in the market. This could further erode market size - creating a potential "death spiral". Alternatively, the project will be "over built" resulting in a lot of redundent capital tied up, receiving an inadequate return on investment.	Target market of about 600 TJ/d, 175 PJ/a represents more than 25% of the EA domestic market. Securing that level of market penetration on a long term basis will be difficult, particularly given that existing contracts will need to expire before prospective customers can move to WEP sources. Evaluated as financial impact to the Proponent, insufficient revenue to justify the project	Likely	High	High
Threat	Alternative lower cost gas supplies	Alternative lower cost gas supplies become available in the East Coast market (e.g NSW and /or Victoria open up CSG industries; NT unconventional gas resources in Beetaloo Basin developed; LNG import terminal)	There are a number of potential new sources of gas supply that would be closer to the main EA demand centres and therefore have lower transport costs incurred in accessing those markets. These include new conventional gas fields both onshore and offshore (Bass Strait); CSG in NSW and Victoria; unconventional (tight gas, shale gas, basin-centred gas) in South Australia and NT), as well as possible LNG imports. All of these face different levels of technical, commercial and regulatory risk, but any of them could emerge to challenge WEP's market opportunity.	Several more proximate options that, while facing their own challenges, are potentially no more challenging than WEP	Possible	High	High
Threat	New north/south pipelines	New pipelines constructed running north/south to bring Qld CSG or NT gas into southern state markets. This issue is a subset of the alternative supply risk	If such pipelines were to be built, linking in alternative new sources of gas supply, they could potentially undercut/erode the market opportunity for WEP.	Natural monopoly characteristics of large transmission pipelines mean that this risk is binary. If WEP is built before a new competing pipeline, it will have tied up much of the market opportunity that the new pipeline would need to access in order to make it viable. However, if a new pipeline gets in ahead of WEP it would most likely take the market that WEP would need to be viable.	Possible	High	High

Risk Type	Risk / Opportunity [Brief name for risk/opp]	Risk / opp description [Outline of what could happen]	Key impact analysis [Provide brief basis for the magnitude of the consequence/opportunity]	Evaluation Rationale [Record why the risk has been evaluated at the level shown to the right]	Likelihood [Based on currently known data and no new mitigation]	Consequence [Based on currently known data and no new mitigation]	Initial Risk Rating (IRR)
Commercial & Market							
Threat	Insufficient gas shipper commitment	Insufficient gas transporters willing to take long term shipping contracts to underpin the project.	It is unlikely that WEP could be financed without gas shippers willing to enter as foundation customers into long term (15 - 20 year) ship or pay contracts for most, if not all, of the capacity in the pipeline. This is because the revenue risk for the pipeline owners and debt providers would be too great.	Gas retailers and large industrial consumers face uncertain circumstances in which they are unlikely to have confidence regarding their gas commodity and transport requirements ten years out. Recent regulatory changes also increase contracting risks. They would therefore find entering into 10-year+ ship-or-pay contracts very challenging. Queensland LNG Projects may be the most likely long-term shippers. Government/s could underwrite the capacity (cf SECWA and DBNGP) but this would be very risky.	Likely	High	High
Threat	Insufficient gas buyer commitment	Insufficient gas buyers willing to take long term gas purchase contracts to underpin the project	It is unlikely that WEP could get the necessary gas supply commitments from WA producers to underpin long term (15-20 year) operation of the pipeline unless there are enough gas buyers willing to enter into long-term Gas Sales Agreements covering that committed gas supply.	Unless there is an intermediary buyer willing to take on the market risk of on-selling the full quantity of gas to end users, the pipeline proponents will end up standing between the producer/s in WA and the gas buyers in EA, reliant on them being able to reach the necessary gas sale and purchase commitments in a co-ordinated manner. Unless those sales agreements come together, there is little prospect of WEP being able to sign up shipping customers and moving to a final investment decision. However, the sale and purchase commitments will rely fundamentally on the WEP proceeding. Bad 'chicken and egg' problem.	Likely	High	High
Threat	Inability to secure sufficient committed gas supply	Gas producers unwilling to commit sufficient gas reserves and production capacity, over sufficient time period, to underpin the project	As above, it is unlikely that WEP could get the necessary gas supply commitments from WA producers to underpin long term (15-20 year) operation of the pipeline unless there are enough gas buyers willing to enter into long-term Gas Sales Agreements covering that committed gas supply.	As above. There will be great challenges involved in creating commercial alignment between WA gas producers, WEP investors and EA gas shippers and buyers. Each party will be dependent on the others, and none will be willing to commit without knowing that the others are similarly committed.	Likely	High	High

Risk Type	Risk / Opportunity [Brief name for risk/opp]	Risk / opp description [Outline of what could happen]	Key impact analysis [Provide brief basis for the magnitude of the consequence/opportunity]	Evaluation Rationale [Record why the risk has been evaluated at the level shown to the right]	Likelihood [Based on currently known data and no new mitigation]	Consequence [Based on currently known data and no new mitigation]	Initial Risk Rating (IRR)
Commercial & Market							
Threat	WA Government withholds gas supply for WA use	WA Government decides that committing the required volumes of gas to the WEP would leave WA consumers at risk of short supply, high prices. It therefore refuses to issue necessary approvals to allow the project to proceed.	If the WA Government was to withhold necessary approvals because of concerns over the potential impact of WEP exports on supply and price of gas for WA consumers, the project could not proceed. No commercial decision to proceed with WEP could be made without assured access to sufficient quantities of gas, at agreed prices, quality etc, to enable EA gas consumers to take on the necessary GTA obligations.	The WA Government would not lightly take action that could reasonably be seen as restricting free and fair trade between the States. However, there are concerns reflected in the WA Government consultation responses and documented in the latest WA Gas Statement of Opportunities study about medium to long term adequacy of gas supply in WA. The WA Government is likely therefore to want to be satisfied about long-term adequacy of domestic gas supply before facilitating exports to the eastern States.	Possible	High	High
Threat	Changes in market demand on East Coast	Renewables and/or other fuel sources reduce market demand for natural gas	There is uncertainty about long term gas demand in Eastern Australia, driven by a) potential for a combinatin of renewable generation and utility-scale battery storage to replace gas-fired generation, and b) potential erosion of retail gas demand by a shift from gas t electric appliances (eg reverse cycle air conditioning; induction electic cooktops)	The key issue for WEP is not whether these market developments will occur, but whether the risk that they pose will prevent gas buyers and shippers making the long-term commitments to buy gas and transport services that will be needed to underpin investment in the WEP.	Possible	High	High
Threat	Switch to renewables for energy supply	Energy operators and/or governments pursue more aggressive renewables targets in their energy mix	As above. The continued uptake and declining cost curve for renewable generation, together with the prospects of large-scale battery storage that could provide a solution to the problem of renewable generation intermittency, creates significant uncertainty about long term demand for gas-fired power generation in EA.	As above, the key issue for WEP is whether this risk will discourage gas buyers and shippers from making the necessary long-term commitments for gas and transport services that will be needed to underpin investment in the WEP.	Possible	High	High
Threat	Failure to secure project financing	The various commercial, market and regulatory risks set out above, when taken together, result in an overall risk profile that equity investors and debt providers are unwilling to support.	If commercial parties are unwilling to take on the aggregate risks faced by the WEP, then the project cannot proceed unless there are other parties (most likely Government/s) willing to derisk the project.	ACIL Allen's modelling of the potential for the WEP to achieve 'critical mass' penetration of the EA market indicate that, under reasonable assumptions about gas price and sustainable pipeline tariffs, the level of market demand required to provide commercial justification for WEP is likely to be at least 10 years away. At this point in time we therefore think it unlikely that investors and debt providers would commit to the project without derisking through some form of Government underwriting.	Likely	High	High

F.2.2 Post-mitigation Risk Assessment

Risk Type	Risk / Opportunity [Brief name for risk/opp]	Known existing mitigation measures	Recommended additional mitigation measures or opportunity actions. [Include commentary and order of magnitude of cost to implement the mitigation measure.]	Key impact analysis [Provide brief basis for the magnitude of the consequence/opportunity with mitigation measures or opportunity actions in place]	Likelihood [Based on currently known data and proposed new mitigation]	Consequence [Based on currently known data and proposed new mitigation]	Residual Risk Rating (RRR)
Routing							
Threat	Options selection process	InDeGO MCA process should identify suitable route. Stakeholder negotiations to proceed prior to selecting final route to identify any constraints and to identify alternative routes that areless constrained.	Undertake field aerial survey to identify areas of concern w.r.t. pipeline construction and operation. Include alternative routes. Survey cost less than $1 million depending on method used - e.g. helicopter, fixed wing, drones, etc.	Mitigation measures should reduce consequence acceptable levels.	Unlikely	High	Moderate
Threat	InDeGO Route selection software	InDeGO criteria levels to be vetted with stakeholders during consultation process. Rerun of model after confirmation.	Undertake parallel negotiations for alternative routes based on InDeGO analysis using different parameters - e.g. mine tenements seen as only slightly constrained. Cost of additional analysis and stakeholder consultation likely to be less than $1 million.	Multiple model runs using varied inputs/ parameters and additional stakeholder negotiations should minimise need to change pipeline route.	Possible	Low	Low
Threat	Changed route selection criteria	InDeGO MCA process plus stakeholder consultation should identify critical criteria before a final route is selected.	Undertake parallel negotiations for alternative routes based on InDeGO analysis using different selection criteria. Cost of additional analysis and stakeholder consultation likely to be less than $1 million.	Multiple model runs using varied inputs/ parameters and additional stakeholder negotiations should minimise need to change pipeline route.	Possible	Moderate	Moderate
Threat	Pipeline access is restricted	Detailed site survey during engineering phase of project to identify inaccessible areas and possible alternatives	Undertake field aerial survey to identify areas of concern w.r.t. pipeline construction and operation. Include alternative routes. Survey cost less than $1 million depending on method used - e.g. helicopter, fixed wing, drones, etc.	Mitigation measures should reduce consequence to acceptable levels.	Possible	Low	Low
Opportunity	Intermediate gas supplies / offtakes identified	During feasibility study undertake further demand analysis to identfy the benefits of this opportunity		This may present an economic opportunity to the state, but would not be of much benfit to the pipeline			#N/A

Risk Type	**Risk / Opportunity** [Brief name for risk/opp]	**Known existing mitigation measures**	**Recommended additional mitigation measures or opportunity actions.** [Include commentary and order of magnitude of cost to implement the mitigation measure.]	**Key impact analysis** [Provide brief basis for the magnitude of the consequence/opportunity with mitigation measures or opportunity actions in place]	**Likelihood** [Based on currently known data and proposed new mitigation]	**Consequence** [Based on currently known data and proposed new mitigation]	**Residual Risk Rating (RRR)**
Design, Construction & Delivery							
Threat	Construction contract	Contract tender process and negotiation with more than 1 contractor			Unlikely	Moderate	Low
Threat	Construction contractor	Contract tender process to include an expression of interest / prequalification / shortlisting phase to ensure only qualified contractors are invited to bid.	Commercial protections under the contract	Evaluated as a 5 -30% CAPEX exceedance and potential liquidated damages based on having to negotiate with additional contractor with potential project delays (>12 months) and loss of gas sales revenue, negative media coverage	Unlikely	Moderate	Low
Threat	Pipeline design	Tender process to include an expression of interest / prequalification / shortlisting phase to ensure only qualified organisations are invited to bid.	Consider novating design contract to construction contractor so the contractor has control of the design schedule and can adapt construction schedule to suit. Third party validation of pipeline design		Possible	Low	Low
Threat	Pipeline materials	Early procurement of long lead items.	Use of multiple pipe mills to supply main line pipe to required specification. May result in cost savings due to different foreign exchange rates for the different mills. Should have minimal impact on project management costs.	Use of multiple mills should improve deliveries and hence avoid schedule delays.	Possible	Low	Low
Threat	Pipeline route access for construction	Early delivery of pipeline materials with 6 month lead times and stockpiling at suitable locations prior to installation.			Possible	Low	Low
	Construction conditions	Project scheduling, geotech studies aligned with route selection	Contractual management of the risk	<5% exceedance of CAPEX	Possible	Low	Low
	Industrial Relations	Early planning of IR strategy	Contractual management of the risk	<6 months delay	Possible	Low	Low

Risk Type	Risk / Opportunity [Brief name for risk/opp]	Known existing mitigation measures	Recommended additional mitigation measures or opportunity actions. [Include commentary and order of magnitude of cost to implement the mitigation measure.]	Key impact analysis [Provide brief basis for the magnitude of the consequence/opportunity with mitigation measures or opportunity actions in place]	Likelihood [Based on currently known data and proposed new mitigation]	Consequence [Based on currently known data and proposed new mitigation]	Residual Risk Rating (RRR)
Approvals							
Threat	Jurisdictional development approvals	Early and constant engagement with all parties (Commonwealth and State), consistency of approach between core project teams within the parties	Establish a steering committee across the jurisdictions to coordinat the Approvals process across the respective jurisdictions in the context that this is a major project	6-12 month delays	Possible	Moderate	Moderate
Threat	EPBC approvals	Early and constant engagement with the DOEE Provide clear scope of work to field teams Proponent is prepared to provide offset		<6 month delay	Possible	Low	Low
Threat	Landowner approvals	Early engagement with landowners and establishment of a negotiating team	Commonweaklth and State Governments can compulsorily acquire land	<6 month delay	Possible	Low	Low
Threat	Native Title claims	Assemble team to undertake and manage the native title process Early engagement with native title claimants		6-12 month delays	Possible	Moderate	Moderate
Threat	Cultural Heritage sites	Provide clear scope of work to experienced field teams Capability to realign pipeline through obtaining a wider corridor established initially		<6 months	Possible	Low	Low
Threat	Community / stakeholder opposition to the project	Early engagement with community and develop[ment of a communiy consultation process in the next phase	establishment of a major projects steering committee	<6 months	Unlikely	Low	Low
Threat	Investigations for environmental approval are not well defined	Early and constant engagement with the regulators Provide clear scope of work to field teams		6-12 month delays	Possible	Moderate	Moderate
Threat	Timeframe for approvals exceeds two years	Early and constant engagement with the regulators Provide clear scope of work to field teams		6-12 month delays	Possible	Moderate	Moderate

Risk Type	**Risk / Opportunity** [Brief name for risk/opp]	**Known existing mitigation measures**	**Recommended additional mitigation measures or opportunity actions.** [Include commentary and order of magnitude of cost to implement the mitigation measure.]	**Key impact analysis** [Provide brief basis for the magnitude of the consequence/opportunity with mitigation measures or opportunity actions in place]	**Likelihood** [Based on currently known data and proposed new mitigation]	**Consequence** [Based on currently known data and proposed new mitigation]	**Residual Risk Rating (RRR)**
Economics							
Threat	Project costing	Detailed feasibility study	Commercial protections under the contract	<5% CAPEX exceedance	Unlikely	Low	Low
Threat	Project cost overuns						#N/A
Threat	Currency fluctuations	Currency hedging		Currency fluction of +10% would result in about 3% budget increase. Hedging should be able to minimise the impact of fluctuations	Likely	Low	Moderate
Threat	Operational costs	Detailed feasibility study		Evaluated as a <5% OPEX exceedance	Possible	Low	Low
Threat	Under-estimation of project costing				Unlikely	Moderate	Low
Threat	Project cost overuns				Possible	Moderate	Moderate
Threat	Currency fluctuations				Possible	Low	Low

Risk Type	Risk / Opportunity [Brief name for risk/opp]	Known existing mitigation measures	Recommended additional mitigation measures or opportunity actions. [Include commentary and order of magnitude of cost to implement the mitigation measure.]	Key impact analysis [Provide brief basis for the magnitude of the consequence/opportunity with mitigation measures or opportunity actions in place]	Likelihood [Based on currently known data and proposed new mitigation]	Consequence [Based on currently known data and proposed new mitigation]	Residual Risk Rating (RRR)
Economics							
Threat	Operational costs				Unlikely	Low	Low
Threat	Delivered cost of gas too high	Secure sufficient gas buyer commitments prior to FID			Unlikely	Low	Low
Threat	New pipeline regulations discourage investors	Seek and gain appropriate relief from provisions of the the National Gas Rules that may otherwise prevent securing sufficient shipper commitments			Unlikely	Low	Low
Threat	"Pre-emptive" investment decision	Secure sufficient commercial commitments to derisk the project enabling FID			Unlikely	Low	Low
Opportunity	East Coast energy security	Subject to securing sufficient commercial commitments to derisk the project, construction could proceed resulting in significant security of supply benefits	Government to keep this option under surveillance, and review on a regular basis if this provides the best least-cost way of improving energy security for the East Coast		Unlikely	High	Moderate

Risk Type	Risk / Opportunity [Brief name for risk/opp]	Known existing mitigation measures	Recommended additional mitigation measures or opportunity actions. [Include commentary and order of magnitude of cost to implement the mitigation measure.]	Key impact analysis [Provide brief basis for the magnitude of the consequence/opportunity with mitigation measures or opportunity actions in place]	Likelihood [Based on currently known data and proposed new mitigation]	Consequence [Based on currently known data and proposed new mitigation]	Residual Risk Rating (RRR)
Commercial & Market							
Threat	Insufficient market demand	No commitment to project until market demand shows justification Selection of low cost activities to undertake to position for advancement of project on a just in time basis Identification of critical points where decisions must be taken to advance the project for gas to be available when market demand exists Establish gas supplier Proponents to put together a commercial case to put to the market	Government to keep this option under surveillance, and review on a regular basis the status of this option and other gas supply options		Likely	Low	Moderate
Threat	Alternative lower cost gas supplies	No commitment to project until market demand shows justification Selection of low cost activities to undertake to position for advancement of project on a just in time basis Identification of critical points where decisions must be taken to advance the project for gas to be available when market demand exists Establish gas supplier Proponents to put together a commercial case to put to the market	Government to keep this option under surveillance, and review on a regular basis the status of other gas supply options		Possible	Low	Low
Threat	New north/south pipelines	This issue is a subset of the alternative gas sources risk, and will be mitigated by: No commitment to project until market demand shows justification Selection of low cost activities to undertake to position for advancement of project on a just in time basis Identification of critical points where decisions must be taken to advance the project for gas to be available when market demand exists Establish gas supplier Proponents to put together a commercial case to put to the market	Government to keep alternative developments under surveillance, and review on a regular basis the status of other gas supply options		Possible	Low	Low
Threat	Insufficient gas shipper commitment	Secure sufficient shipper commitments prior to FID			Unlikely	Low	Low

Risk Type	Risk / Opportunity [Brief name for risk/opp]	Known existing mitigation measures	Recommended additional mitigation measures or opportunity actions. [Include commentary and order of magnitude of cost to implement the mitigation measure.]	Key impact analysis [Provide brief basis for the magnitude of the consequence/opportunity with mitigation measures or opportunity actions in place]	Likelihood [Based on currently known data and proposed new mitigation]	Consequence [Based on currently known data and proposed new mitigation]	Residual Risk Rating (RRR)
Commercial & Market							
Threat	Insufficient gas buyer commitment	Secure sufficient gas buyer commitments prior to FID			Unlikely	Low	Low
Threat	Inability to secure sufficient committed gas supply	Secure sufficient gas supply commitments prior to FID			Unlikely	Low	Low
Threat	WA Government withholds gas supply for WA use	Proponent engagement with all jurisdictions to gain public support for project and cooperation	Gain the in-principle support of all major jurisdictions prior to significant expenditure		Unlikely	Low	Low
Threat	Changes in market demand on East Coast	No commitment to project until market demand shows justification Selection of low cost activities to undertake to position for advancement of project on a just in time basis Identification of critical points where decisions must be taken to advance the project for gas to be available when market demand exists	Government to keep this option under surveillance, and review on a regular basis the status of this option and other gas supply options		Possible	Low	Low
Threat	Switch to renewables for energy supply	As above			Possible	Low	Low
Threat	Failure to secure project financing	Secure sufficient commercial commitments to derisk the project enabling FID			Unlikely	Low	Low

G

TASMAN GLOBAL ECONOMIC MODEL

Tasman Global is a dynamic, global computable general equilibrium (CGE) model that has been developed by ACIL Allen for the purpose of undertaking economic impact analysis at the regional, state, national and global level.

A CGE model captures the interlinkages between the markets of all commodities and factors, taking into account resource constraints, to find a simultaneous equilibrium in all markets. A global CGE model extends this interdependence of the markets across world regions and finds simultaneous equilibrium globally. A dynamic model adds onto this the interconnection of equilibrium economies across time periods. For example, investments made today are going to determine the capital stocks of tomorrow and hence future equilibrium outcomes depend on today's equilibrium outcome, and so on.

A dynamic global CGE model, such as *Tasman Global*, has the capability of addressing total, sectoral, spatial and temporal efficiency of resource allocation as it connects markets globally and over time. Being a recursively dynamic model, however, its ability to address temporal issues is limited. In particular, *Tasman Global* cannot typically address issues requiring partial or perfect foresight, however, as documented in Jakeman et al (2001), it is possible to introduce partial or perfect foresight in certain markets using algorithmic approaches. Notwithstanding this, the model does have the capability to project the economic impacts over time of given changes in policies, tastes and technologies in any region of the world economy on all sectors and agents of all regions of the world economy.

Tasman Global was developed out of the 2001 version of the Global Trade and Environment Model (GTEM) developed by ABARE (Pant 2001) and has been evolving ever since. In turn, GTEM was developed out of the MEGABARE model (ABARE 1996), which contained significant advancements over the GTAP model of that time (Hertel 1997).

G.1 A dynamic model

Tasman Global is a model that estimates relationships between variables at different points in time. This is in contrast to comparative static models, which compare two equilibriums (one before a policy change and one following). A dynamic model such as *Tasman Global* is beneficial when analysing issues where both the timing of and the adjustment path that economies follow are relevant in the analysis.

G.2 The database

A key advantage of *Tasman Global* is the level of detail in the database underpinning the model. The database is derived from the Global Trade Analysis Project (GTAP) database. This database is a fully documented, publicly available global data base which contains complete bilateral trade information, transport and protection linkages among regions for all GTAP commodities. It is the detailed database of its type in the world.

Tasman Global builds on the GTAP database by adding the following important features:

- a detailed population and labour market database
- detailed technology representation within key industries (such as electricity generation and iron and steel production)
- disaggregation of a range of major commodities including iron ore, bauxite, alumina, primary aluminium, brown coal, black coal and LNG
- the ability to repatriate labour and capital income
- explicit representation of the states and territories of Australia
- the capacity to represent multiple regions within states and territories of Australia explicitly.

Nominally, version 9.1 of the *Tasman Global* database divides the world economy into 150 regions (142 international regions – including Timor-Leste – plus the 8 states and territories of Australia) although in reality the regions are frequently disaggregated further. ACIL Allen regularly models Australian or international projects or policies at the regional level including at the provincial level for Papua New Guinea and Canada.

The *Tasman Global* database also contains a wealth of sectoral detail currently identifying up to 72 industries (**Table G.1**). The foundation of this information is the input-output tables that underpin the database. The input-output tables account for the distribution of industry production to satisfy industry and final demands. Industry demands, so-called intermediate usage, are the demands from each industry for inputs. For example, electricity is an input into the production of communications. In other words, the communications industry uses electricity as an intermediate input. Final demands are those made by households, governments, investors and foreigners (export demand). These final demands, as the name suggests, represent the demand for finished goods and services. To continue the example, electricity is used by households – their consumption of electricity is a final demand. Each sector in the economy is typically assumed to produce one commodity, although in *Tasman Global*, the electricity, transport and iron and steel sectors are modelled using a ‘technology bundle’ approach. With this approach, different known production methods are used to generate a homogeneous output for the ‘technology bundle’ industry. For example, electricity can be generated using brown coal, black coal, petroleum, base load gas, peak load gas, nuclear, hydro, geothermal, biomass, wind, solar or other renewable based technologies – each of which have their own cost structure.

TABLE G.1 STANDARD SECTORS IN THE TASMAN GLOBAL MODEL

no	Name	no	Name
1	Paddy rice	37	Wood products
2	Wheat	38	Paper products, publishing
3	Cereal grains nec	39	Diesel (incl. nonconventional diesel)
4	Vegetables, fruit, nuts	40	Other petroleum, coal products
5	Oil seeds	41	Chemical, rubber, plastic products
6	Sugar cane, sugar beef	42	Iron ore
7	Plant- based fibres	43	Bauxite
8	Crops nec	44	Mineral products nec
9	Bovine cattle, sheep, goats, horses	45	Ferrous metals
10	Pigs	46	Alumina
11	Animal products nec	47	Primary aluminium
12	Raw milk	48	Metals nec
13	Wool, silk worm cocoons	49	Metal products
14	Forestry	50	Motor vehicle and parts
15	Fishing	51	Transport equipment nec
16	Brown coal	52	Electronic equipment
17	Black coal	53	Machinery and equipment nec
18	Oil	54	Manufactures nec
19	Liquefied natural gas (LNG)	55	Electricity generation
20	Other natural gas	56	Electricity transmission and distribution
21	Minerals nec	57	Gas manufacture, distribution
22	Bovine meat products	58	Water
23	Pig meat products	59	Construction
24	Meat products nec	60	Trade
25	Vegetables oils and fats	61	Road transport
26	Dairy products	62	Rail and pipeline transport
27	Processed rice	63	Water transport
28	Sugar	64	Air transport
29	Food products nec	65	Transport nec
30	Wine	66	Communication
31	Beer	67	Financial services nec
32	Spirits and RTDs	68	Insurance
33	Other beverages and tobacco products	69	Business services nec
34	Textiles	70	Recreational and other services
35	Wearing apparel	71	Public Administration, Defence, Education, Health
36	Leather products	72	Dwellings

SOURCE: ACIL ALLEN CONSULTING

The other key feature of the database is that the cost structure of each industry is also represented in detail. Each industry purchases intermediate inputs (from domestic and imported sources) primary factors (labour, capital, land and natural resources) as well as paying taxes or receiving subsidies.

G.3 Model structure

Given its heritage, the structure of the *Tasman Global* model closely follows that of the GTAP and GTEM models and interested readers are encouraged to refer to the documentation of these models for more detail (namely Hertel 1997 and Pant 2001, respectively). In summary:

— The model divides the world into a variety of regions and international waters.

  - Each region is fully represented with its own 'bottom-up' social accounting matrix and could be a local community, an LGA, state, country or a group of countries. The number of regions in a

given simulation depends on the database aggregation. Each region consists of households, a government with a tax system, production sectors, investors, traders and finance brokers.
  - 'International waters' are a hypothetical region where global traders operate and use international shipping services to ship goods from one region to the other. It also houses an international finance 'clearing house' that pools global savings and allocates the fund to investors located in every region.
  - Each region has a 'regional household'23 that collects all factor payments, taxes, net foreign borrowings, net repatriation of factor incomes due to foreign ownership and any net income from trading of emission permits.
- The income of the regional household is allocated across private consumption, government consumption and savings according to a Cobb-Douglas utility function, which, in practice, means that the share of income going to each component is assumed to remain constant in nominal terms.
- Private consumption of each commodity is determined by maximising utility subject to a Constant Difference of Elasticities (CDE) function which includes both price and income elasticities.
- Government consumption of each commodity is determined by maximising utility subject to a Cobb-Douglas utility function.
- Each region has *n* production sectors, each producing single products using various production functions where they aim to maximise profits (or minimise costs) and take all prices as given. The nature of the production functions chosen in the model means that producers exhibit constant returns to scale.
  - In general, each producer supplies consumption goods by combining an aggregate energy-primary factor bundle with other intermediate inputs and according to a Leontief production function (which in practice means that the quantity shares remain in fixed proportions). Within the aggregate energy-primary factor bundle, the individual energy commodities and primary factors are combined using a nested-CES (Constant Elasticity of Substitution) production function, in which energy and primary factor aggregates substitute according to a CES function with the individual energy commodities and individual primary factors substituting with their respective aggregates according to further CES production functions.
  - Exceptions to the above include the electricity generation, iron and steel and road transport sectors. These sectors employ the 'technology bundle' approach developed by ABARE (1996) in which non-homogenous technologies are employed to produce a homogenous output with the choice of technology governed by minimising costs according to a modified-CRESH production function. For example, electricity may be generated from a variety of technologies (including brown coal, black coal, gas, nuclear, hydro, solar etc.), iron and steel may be produced from blast furnace or electric arc technologies while road transport services may be supplied using a range of different vehicle technologies. The 'modified-CRESH' function differs from the traditional CRESH function by also imposing the condition that the quantity units are homogenous.
- There are four primary factors (land, labour, mobile capital and fixed capital). While labour and mobile capital are used by all production sectors, land is only used by agricultural sectors while the fixed capital is typically employed in industries with natural resources (such as fishing, forestry and mining) or in selected industries built by ACIL Allen.
  - Land supply in each region is typically assumed to remain fixed through time with the allocation of land between sectors occurring to maximise returns subject to a Constant Elasticity of Transformation (CET) utility function.
  - Mobile capital accumulates as a result of net investment. It is implicitly assumed in *Tasman Global* that it takes one year for capital to be installed. Hence, supply of capital in the current period depends on the last year's capital stock and investments made during the previous year.
  - Labour supply in each year is determined by endogenous changes in population, given participation rates and a given unemployment rate. In policy scenarios, the supply of labour is positively influenced by movements in the real wage rate governed by the elasticity of supply.

[23] The term "regional household" was devised for the GTAP model. In essence it is an agent that aggregates all incomes attributable to the residents of a given region before distributing the funds to the various types of regional consumption (including savings).

For countries where sub-regions have been specified (such as Australia), migration between regions is induced by changes in relative real wages with the constraint that net interregional migration equals zero. For regions where the labour market has been disaggregated to include occupations, there is limited substitution allowed between occupations by individuals supplying labour (according to a CET utility function) and by firms demanding labour (according to a CES production function) based on movements in relative real wages.

- The supply of fixed capital is given for each sector in each region.

The model has the option for these assumptions to be changed at the time of model application if alternative factor supply behaviours are considered more relevant.

— It is assumed that labour (by occupation) and mobile capital are fully mobile across production sectors implying that, in equilibrium, wage rates (by occupation) and rental rates on capital are equalised across all sectors within each region. To a lesser extent, labour and capital are mobile between regions through international financial investment and migration, but this sort of mobility is sluggish and does not equalise rates of return across regions.

— For most international regions, each consumer (private, government, industries and the local investment sector), consumption goods can be sourced either from domestic or imported sources. In any country which has disaggregated regions (such as Australian), consumption goods can also be sourced from other intrastate or interstate regions. In all cases, the source of non-domestically produced consumption goods is determined by minimising costs subject to a Constant Ratios of Elasticities of Substitution, Homothetic (CRESH) utility function. Like most other CGE models, a CES demand function is used to model the relative demand for domestically-produced commodities versus non-domestically produced commodities. The elasticities chosen for the CES and CRESH demand functions mean that consumers in each region have a higher preference for domestically produced commodities than non-domestic and a higher preference for intrastate or interstate produced commodities versus foreign.

— The capital account in *Tasman Global* is open. Domestic savers in each region purchase 'bonds' in the global financial market through local 'brokers' while investors in each region sell bonds to the global financial market to raise investible funds. A flexible global interest rate clears the global financial market.

— It is assumed that regions may differ in their risk characteristics and policy configurations. As a result, rates of return on money invested in physical capital may differ between regions and therefore may be different from the global cost of funds. Any difference between the local rates of return on capital and the global cost of borrowing is treated as the result of the existence of a risk premium and policy imperfections in the international capital market. It is maintained that the equilibrium allocation of investment requires the equalisation of changes in (as opposed to the absolute levels of) rates of return over the base year rates of return.

— Any excess of investment over domestic savings in a given region causes an increase in the net debt of that region. It is assumed that debtors service the debt at the interest rate that clears the global financial market. Similarly, regions that are net savers gives rise to interest receipts from the global financial market at the same interest rate.

— Investment in each region is used by the regional investor to purchase a suite of intermediate goods according to a Leontief production function to construct capital stock with the regional investor cost minimising by choosing between domestic, interstate and imported sources of each intermediate good via the CRESH production function. The regional cost of creating new capital stock versus the local rates of return on mobile capital is what determines the regional rate of return on new investment.

— In equilibrium, exports of a good from one region to the rest of world are equal to the import demand for that good in the remaining regions. Together with the merchandise trade balance, the net payments on foreign debt add up to the current account balance. *Tasman Global* does not require that the current account be in balance every year. It allows the capital account to move in a compensatory direction to maintain the balance of payments. The exchange rate provides the flexibility to keep the balance of payments in balance.

— Emissions of six anthropogenic greenhouse gases (namely, carbon dioxide, methane, nitrous oxide, HFCs, PFCs and SF_6) associated with economic activity are tracked in the model. Almost all sources and sectors are represented; emissions from agricultural residues and land-use change and forestry activities are not explicitly modelled but can be accounted for externally. Prices can be applied to emissions which are converted to industry-specific production taxes or commodity-specific sales taxes that impact on demand. Abatement technologies similar to those adopted in Australian Government (2008) are available and emission quotas can be set globally or by region along with allocation schemes that enable emissions to be traded between regions.

More detail regarding specific elements of the model structure are discussed in the following sections.

G.4 Population growth and labour supply

Population growth is an important determinant of economic growth through the supply of labour and the demand for final goods and services. Population growth for each region represented in the *Tasman Global* database is projected using ACIL Allen's in-house demographic model. The demographic model projects how the population in each region grows and how age and gender composition changes over time and is an important tool for determining the changes in regional labour supply and total population over the projection period.

For each of region, the model projects the changes in age-specific birth, mortality and net migration rates by gender for 101 age cohorts (0-99 and 100+). The demographic model also projects changes in participation rates by gender by age for each region, and, when combined with the age and gender composition of the population, endogenously projects the future supply of labour in each region. Changes in life expectancy are a function of income per person as well as assumed technical progress on lowering mortality rates for a given income (for example, reducing malaria-related mortality through better medicines, education, governance etc.). Participation rates are a function of life expectancy as well as expected changes in higher education rates, fertility rates and changes in the work force as a share of the total population.

Labour supply is derived from the combination of the projected regional population by age by gender and the projected regional participation rates by age by gender. Over the projection period labour supply in most developed economies is projected to grow slower than total population as a result of ageing population effects.

For the Australian states and territories, the projected aggregate labour supply from ACIL Allen's demographics module is used as the base level potential workforce for the detailed Australian labour market module, which is described in the next section.

G.4.1 The Australian labour market

Tasman Global has a detailed representation of the Australian labour market which has been designed to capture:

— different occupations

— changes to participation rates (or average hours worked) due to changes in real wages

— changes to unemployment rates due to changes in labour demand

— limited substitution between occupations by the firms demanding labour and by the individuals supplying labour, and

— limited labour mobility between states and regions within each state.

Tasman Global recognises 97 different occupations within Australia – although the exact number of occupations depends on the aggregation. The firms who hire labour are provided with some limited scope to change between these 97 labour types as the relative real wage between them changes. Similarly, the individuals supplying labour have a limited ability to change occupations in response to the changing relative real wage between occupations. Finally, as the real wage for a given occupation rises in one state relative to other states, workers are given some ability to respond by shifting their location. The model produces results at the 97 3-digit ANZSCO (Australian New Zealand Standard Classification of Occupations) level which are presented in **Table G.2**.

The labour market structure of *Tasman Global* is thus designed to capture the reality of labour markets in Australia, where supply and demand at the occupational level do adjust, but within limits.

Labour supply in *Tasman Global* is presented as a three-stage process:

1. labour makes itself available to the workforce based on movements in the real wage and the unemployment rate;
2. labour chooses between occupations in a state based on relative real wages within the state; and
3. labour of a given occupation chooses in which state to locate based on movements in the relative real wage for that occupation between states.

By default, *Tasman Global*, like all CGE models, assumes that markets clear. Therefore, overall, supply and demand for different occupations will equate (as is the case in other markets in the model).

TABLE G.2 OCCUPATIONS IN THE *TASMAN GLOBAL* DATABASE, ANZSCO 3-DIGIT LEVEL (MINOR GROUPS)

ANZSCO code, Description

1. MANAGERS

111 Chief Executives, General Managers and Legislators
121 Farmers and Farm Managers
131 Advertising and Sales Managers
132 Business Administration Managers
133 Construction, Distribution and Production Managers
134 Education, Health and Welfare Services Managers
135 ICT Managers
139 Miscellaneous Specialist Managers
141 Accommodation and Hospitality Managers
142 Retail Managers
149 Miscellaneous Hospitality, Retail and Service Managers

2. PROFESSIONALS

211 Arts Professionals
212 Media Professionals
221 Accountants, Auditors and Company Secretaries
222 Financial Brokers and Dealers, and Investment Advisers
223 Human Resource and Training Professionals
224 Information and Organisation Professionals
225 Sales, Marketing and Public Relations Professionals
231 Air and Marine Transport Professionals
232 Architects, Designers, Planners and Surveyors
233 Engineering Professionals
234 Natural and Physical Science Professionals
241 School Teachers
242 Tertiary Education Teachers
249 Miscellaneous Education Professionals
251 Health Diagnostic and Promotion Professionals
252 Health Therapy Professionals
253 Medical Practitioners
254 Midwifery and Nursing Professionals
261 Business and Systems Analysts, and Programmers
262 Database and Systems Administrators, and ICT Security Specialists
263 ICT Network and Support Professionals
271 Legal Professionals
272 Social and Welfare Professionals

3. TECHNICIANS & TRADES WORKERS

311 Agricultural, Medical and Science Technicians
312 Building and Engineering Technicians
313 ICT and Telecommunications Technicians
321 Automotive Electricians and Mechanics
322 Fabrication Engineering Trades Workers
323 Mechanical Engineering Trades Workers
324 Panelbeaters, and Vehicle Body Builders, Trimmers and Painters
331 Bricklayers, and Carpenters and Joiners
332 Floor Finishers and Painting Trades Workers
333 Glaziers, Plasterers and Tilers
334 Plumbers
341 Electricians
342 Electronics and Telecommunications Trades Workers
351 Food Trades Workers
361 Animal Attendants and Trainers, and Shearers
362 Horticultural Trades Workers
391 Hairdressers
392 Printing Trades Workers
393 Textile, Clothing and Footwear Trades Workers
394 Wood Trades Workers
399 Miscellaneous Technicians and Trades Workers

4. COMMUNITY & PERSONAL SERVICE

411 Health and Welfare Support Workers
421 Child Carers
422 Education Aides
423 Personal Carers and Assistants
431 Hospitality Workers
441 Defence Force Members, Fire Fighters and Police
442 Prison and Security Officers
451 Personal Service and Travel Workers
452 Sports and Fitness Workers

5. CLERICAL & ADMINISTRATIVE

511 Contract, Program and Project Administrators
512 Office and Practice Managers
521 Personal Assistants and Secretaries
531 General Clerks
532 Keyboard Operators
541 Call or Contact Centre Information Clerks
542 Receptionists
551 Accounting Clerks and Bookkeepers
552 Financial and Insurance Clerks
561 Clerical and Office Support Workers
591 Logistics Clerks
599 Miscellaneous Clerical and Administrative Workers

6. SALES WORKERS

611 Insurance Agents and Sales Representatives
612 Real Estate Sales Agents
621 Sales Assistants and Salespersons
631 Checkout Operators and Office Cashiers
639 Miscellaneous Sales Support Workers

7. MACHINERY OPERATORS & DRIVERS

711 Machine Operators
712 Stationary Plant Operators
721 Mobile Plant Operators
731 Automobile, Bus and Rail Drivers
732 Delivery Drivers
733 Truck Drivers
741 Storepersons

8. LABOURERS

811 Cleaners and Laundry Workers
821 Construction and Mining Labourers
831 Food Process Workers
832 Packers and Product Assemblers
839 Miscellaneous Factory Process Workers
841 Farm, Forestry and Garden Workers
851 Food Preparation Assistants
891 Freight Handlers and Shelf Fillers
899 Miscellaneous Labourers

SOURCE: ABS (2009), ANZSCO – AUSTRALIAN AND NEW ZEALAND STANDARD CLASSIFICATIONS OF OCCUPATIONS, FIRST EDITION, REVISION 1, ABS CATALOGUE NO. 1220.0.

Labour market database

The *Tasman Global* database includes a detailed representation of the Australian labour market which has been designed to capture the supply and demand for different skills and occupations by industry. To achieve this, the Australian workforce is characterised by detailed supply and demand matrices.

On the supply side, the Australian population is characterised by a five-dimensional matrix consisting of:

- 7 post-school qualification levels
- 12 main qualification fields of highest educational attainment
- 97 occupations
- 101 age groups (namely 0 to 99 and 100+)
- 2 genders.

The data for this matrix is measured in persons and was sourced from the ABS 2011 Census. As the skills elements of the database and model structure have not been used for this project, it will be ignored in this discussion.

The 97 occupations are those specified at the 3-digit level (or Minor Groups) under the Australian New Zealand Standard Classification of Occupations (ANZSCO) (see **Table G.2**).

On the demand side, each industry demands a particular mix of occupations. This matrix is specified in units of full-time equivalent (FTE) jobs where an FTE employee works an average of 37.5 hours per week. Consistent with the labour supply matrix, the data for FTE jobs by occupation by industry was also sourced from the ABS 2011 Census and updated using the latest labour force statistics.

Matching the demand and supply side matrices means that there is the implicit assumption that the average hours per worker are constant, but it is noted that mathematically changes in participation rates have the same effect as changes in average hours worked.

G.4.2 Labour market model structure

In the model, the underlying growth of each industry in the Australian economy results in a growth in demand for a particular set of skills and occupations. In contrast, the supply of each set of skills and occupations in a given year is primarily driven by the underlying demographics of the resident population. This creates a market for each skill by occupation that (unless specified otherwise) needs to clear at the start and end of each time period.[24] The labour markets clear by a combination of different prices (i.e. wages) for each labour type and by allowing a range of demand and supply substitution possibilities, including:

- changes in firms demand for labour driven by changes in the underlying production technology:
  - for technology bundle industries (electricity, iron and steel and road transportation) this occurs due to changes between explicitly identified alternative technologies
  - for non-technology bundle industries this includes substitution between factors (such as labour for capital) or energy for factors
- changes to participation rates (or average hours worked) due to changes in real wages
- changes in the occupations of a person due to changes in relative real wages
- substitution between occupations by the firms demanding labour due to changes in the relative costs
- changes to unemployment rates due to changes in labour demand, and
- limited labour mobility between states due to changes in relative real wages.

All of the labour supply substitution functions are modified-CET functions in which people supply their skills, occupation and rates of participation as a positive function of relative wages. However, unlike a

[24] For example, at the start and end of each week for this analysis. *Tasman Global* can be run with different steps in time, such as quarterly or bi-annually in which case the markets would clear at the start and end of these time points.

standard CET (or CES) function, the functions are 'modified' to enforce an additional constraint that the number of people is maintained before and after substitution.[25]

Although technically solved simultaneously, the labour market in *Tasman Global* can be thought of as a five-stage process:

1. labour makes itself available to the workforce based on movements in the real wage (that is, it actively participates with a certain number of average hours worked per week)
2. the age, gender and occupations of the underlying population combined with the participation rate by gender by age implies a given supply of labour (the potentially available workforce)
3. a portion of the potentially available workforce is unemployed implying a given available labour force
4. labour chooses to move between occupations based on relative real wages
5. industries alter their demands for labour as a whole and for specific occupations based on the relative cost of labour to other inputs and the relative cost of each occupation.

By default, *Tasman Global*, like all CGE models, assumes that markets clear at the start and end of each period. Therefore, overall, supply and demand for different occupations will equate (as is the case in other markets in the model). In principle, (subject to zero starting values) people of any age and gender can move between any of the 97 occupations while industries can produce their output with any mix of occupations. However, in practice the combination of the initial database, the functional forms, low elasticities and moderate changes in relative prices for skills, occupations etc. means that there is only low to moderate change induced by these functions. The changes are sufficient to clear the markets, but not enough to radically change the structure of the workforce in the timeframe of this analysis.

Factor-factor substitution elasticities in non-technology bundle industries are industry specific and are the same as those specified in the GTAP database[26], while the fuel-factor and technology bundle elasticities are the same as those specified in GTEM.[27] The detailed labour market elasticities are ACIL Allen assumptions, previously calibrated in the context of the model framework to replicate the historical change in the observed Australian labour market over a five year period[28]. The unemployment rate function in the policy scenarios is a non-linear function of the change in the labour demand relative to the reference case with the elasticity being a function of the unemployment rate (that is, the lower the unemployment rate the lower the elasticity and the higher the unemployment rate the higher the elasticity).

G.5 References

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[25] As discussed in Dixon et al (1997), a standard CES/CET function is defined in terms of *effective units*. Quantitatively this means that, when substituting between, say, X_1 and X_2 to form a total quantity X using a CET function a simple summation generally does not actually equal X. Use of these functions is common practice in CGE models when substituting between substantially different units (such as labour versus capital or imported versus domestic services) but was not deemed appropriate when tracking the physical number of people. Such 'modified' functions have long been employed in the technology bundles of *Tasman Global* and GTEM. The Productivity Commission have proposed alternatives to the standard CES to overcome similar and other weaknesses when applied to internationally traded commodities.

[26] Narayanan et al. (2012).

[27] Pant (2007).

[28] This method is a common way of calibrating the economic relationships assumed in CGE models to those observed in the economy. See for example Dixon and Rimmer (2002).

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LIFTING OF NT FRACKING MORATORIUM

On 17 April 2018 the Northern Territory Government announced the lifting of a moratorium on shale gas exploration requiring the use of hydraulic fracturing for reservoir stimulation. As a result, exploration for shale gas in the Beetaloo Sub-basin of the McArthur Basin is expected to resume, subject to strict operational and environmental controls.

Based on the anticipated resumption of shale gas exploration in the Northern Territory, pipeline company Jemena announced that it will consider a major expansion and extension of its Northern Gas Pipeline, currently under construction between Tennant Creek and Mount Isa. According to Jemena, the cost of the expansion project could be around $3 to $4 billion with a deliverability capability of up to 700 TJ/day, making it larger in terms of transport capacity than the West–East Pipeline development concept tested in the pre-feasibility study.

These Northern Territory developments, should they proceed, would have significant negative consequences for the viability of a West–East Pipeline between Western Australia and the eastern states.

Discussion

A recommencement of exploration in the Beetaloo Sub-basin is now anticipated following the NT Government's decision to lift the moratorium. However, before exploration can resume, legislation will be required to give effect to the 135 recommendations of the independent scientific inquiry which have been accepted, as a package, by the NT Government. The Government is aiming to complete the legislative program by the end of 2018 and, subject to the passage of that legislation and the necessary administrative arrangements, exploration companies have indicated that they hope to resume operations in the Beetaloo Sub-basin in the next dry season, starting mid-2019.

Exploration, well-testing and pilot production activities are likely to take at least four to five years. Therefore, under the most optimistic scenario, first commercial production of Northern Territory shale gas might commence around 2023–24. Depending on the results achieved during exploration and testing, the lead time to commercial production may be longer, and is there no guarantee of ultimate commercial success. Nevertheless, the companies involved in shale gas exploration in the Northern Territory have expressed confidence in the potential of the Beetaloo play, and large contingent gas resources have already been booked. Whatever the eventual outcome, the resumption of exploration activity is an important step that would significantly enhance the prospects of the Northern Territory becoming a major supplier of gas to the eastern Australian market.

Implications for the West–East Pipeline

During the consultation process undertaken as part of the West–East Pipeline Pre-feasibility Study, several stakeholders pointed to the risk to the pipeline posed by potential new sources of supply in the

Northern Territory and the eastern States. The Beetaloo Sub-basin was seen as having strong prospects and potentially offering more competitive gas supply that could undercut the economics of a West–East Pipeline. Some stakeholders suggested that, if the moratorium on hydraulic fracturing of shale gas in the Northern Territory was lifted, gas supply from the Beetaloo Sub-basin could make a West-East Pipeline non-viable.

The preliminary risk evaluation undertaken as part of the pre-feasibility study identified the potential emergence of other, lower cost sources of supply closer to the eastern Australian market (including Beetaloo shale gas) as a key risk to the viability of the West–East Pipeline, but noted that the risk could be mitigated by deferring any financial commitment until such time as it becomes apparent that the alternative supply sources are unlikely to emerge. To that end, the report recommends that the Government should keep alternative developments under surveillance and should review, on a regular basis, the status of other gas supply options.

Consistent with this finding, the report recommends a ‘phased, gated’ decision process for progressing the West–East Pipeline option, the first phase of which would involve a process of monitoring and periodic review of the West–East Pipeline’s prospects as a commercially feasible and desirable option for bolstering east coast gas supply, including assessments of progress on other east coast gas supply options.

The lifting of the Northern Territory moratorium highlights the importance of monitoring progress on other east coast gas supply options before making any decision to push ahead with an East–West Pipeline.

If following a resumption of exploration in the Beetaloo Sub-basin it is demonstrated that NT shale gas can be delivered, competitively and in large volumes, into the eastern Australian market, then any commercial case for construction of a West–East Pipeline will be weakened considerably and potentially extinguished.

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